PDHonline Course C746 (8 PDH)

Hydraulic Fracturing - A Comprehensive & Balanced Review

Instructor: H. Wayne Harper, PE

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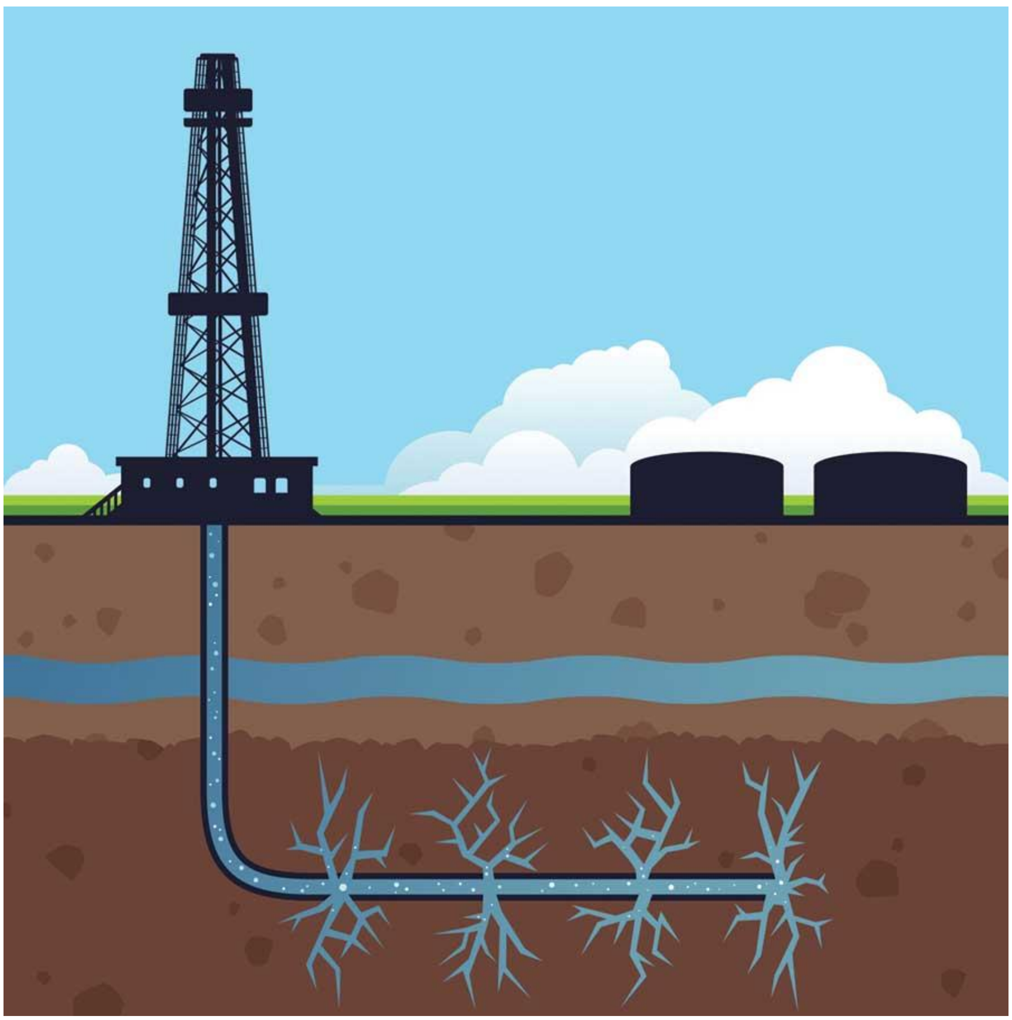
HYDRAULIC FRACTURING:

A COMPREHENSIVE AND BALANCED REVIEW



BY:

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SEPTEMBER 2014

HYDRAULIC FRACTURING: A COMPREHENSIVE AND BALANCED REVIEW

TABLE OF CONTENTS

CURRENT HYDRAULIC FRACTURING PRACTICES – FAVORABLE DOCUMENTATION

SHALE GAS – APPLYING TECHNOLOGY TO SOLVE AMERICA'S ENERGY CHALLENGE

BY: UNITED STATED DEPARTMENT OF ENERGY / NATIONAL ENERGY TECHNOLOGY LABORATORY

HYDRAULIC FRACTURING: HOW IT WORKS

BY: FRAC FOCUS

MODERN SHALE GAS DEVELOPMENT IN THE UNITED STATES: A PRIMER

BY: UNITED STATES DEPARTMENT OF ENERGY

"TRUTHLAND" – AN ENERGY INDUSTRY DOCUMENTARY RESPONSE TO THE "GASLAND" MOVIE

BY: ENERGY-IN-DEPTH AND THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

COLORADO OIL AND GAS CONSERVATION COMMISSION RESPONSE TO THE "GASLAND" MOVIE

BY: COLORADO OIL AND GAS CONSERVATION COMMISSION;

CURRENT HYDRAULIC FRACTURING PRACTICES – NEUTRAL DOCUMENTATION

HYDRAULIC FRACTURING

BY: WIKIPEDIA, THE FREE ENCYCLOPEDIA

STUDY OF THE POTENTIAL IMPACTS OF HYDRAULIC FRACTURING ON DRINKING WATER RESOURCES

BY: UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

CURRENT HYDRAULIC FRACTURING PRACTICES – NON-FAVORABLE DOCUMENTATION

ENVIRONMENTAL IMPACTS OF HYDRAULIC FRACTURING

BY: EARTHWORKS

THE OIL AND GAS INDUSTRY'S EXCLUSIONS AND EXEMPTIONS TO MAJOR ENVIRONMENTAL STATUTES

BY: EARTHWORKS / OIL & GAS ACCOUNTABILITY PROJECT

GASLAND 1 & 2

BY: JOSH FOX

ProPublica – Journalism in the Public Interest

Series: Fracking – Gas Drilling's Environmental Threat

FUTURE HYDRAULIC FRACTURING PRACTICES – WATERLESS

"A New Way of Fracking"

Science and Technology magazine*, May 12, 2014*

EXECUTIVE SUMMARY

1.0 Introduction to the Author / Course Complier

Mr. Harper is a professionally licensed Environmental Engineer with approximately 25-years experience protecting sensitive environmental resources. Much of these work efforts have focused on Federal Energy Regulatory Commission (F.E.R.C.) regulated natural gas systems in every phase of their project lifecycle, including:

- Transmission pipelines
  - Design and permitting
  - Construction management and regulatory compliance
  - Project clean-up / restoration
  - Facility operations
- Liquefied natural gas (LNG) facilities
  - Renovation
  - Operations

It is my professional goal to help facilitate the development of energy projects while concurrently promoting the responsible, good stewardship of God's creation. Contrary to some beliefs, this approach is both possible and effective. Success is achieved through a high quality, thoughtful plan which is well implemented.

2.0 Course Overview

During the preparatory research for this course, it quickly became apparent that oil and natural gas extraction utilizing hydraulic fracturing is an extremely controversial topic. Both proponents and antagonists have propagated their respective data and viewpoints, at times passionately, to the general public. These pro- and con- positions can typically be characterized as vastly divergent. It seems the middle ground on this issue is populated by individuals who do not yet know enough details to form an opinion and choose sides.

It is in this context that a non-judgmental and balanced approach for this course was developed. Specifically, the comprehensive data and research on hydraulic fracturing contained herein has been grouped and presented in the following categories:

Current Hydraulic Fracturing Practices

- Favorable documentation
- Neutral documentation
- Non-favorable documentation

Future Hydraulic Fracturing Practices

- “Water-Free” Fracking

The “favorable documentation” group was selected to be presented first, not because of any bias or endorsement for this position, but because it contains portions that do an excellent job in describing the hydraulic fracturing process. This understanding is a necessary foundation to appropriately evaluate the remainder of the course material. In consolation to supporters of the “non-favorable documentation” group, this viewpoint will at least have the last word.

As the author / course compiler, my goal is to fairly present comprehensive information on hydraulic fracturing, from various viewpoints, with no conclusions or final analysis. I will leave the ultimate evaluation up to the reader.

The following sections describe the individual components documented in each of the three categories.

3.0 Current Hydraulic Fracturing Practices – Overview of the “Favorable Documentation”

3.1 Shale Gas – Applying Technology to Solve America’s Energy Challenge

By: United Stated Department of Energy / National Energy Technology Laboratory

http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

3.1.1 About the United States Department of Energy (USDOE)

The United States Department of Energy (DOE) is a Cabinet-level department of the United States government concerned with the United States' policies regarding energy and safety in handling nuclear material. Its responsibilities include the nation's nuclear weapons program, nuclear reactor production for the United States Navy, energy conservation, energy related research, radioactive waste disposal, and domestic energy production. It also directs research in genomics; the Human Genome Project originated in a DOE initiative.[2] DOE sponsors more research in the physical sciences than any other US federal agency;[3] the majority of this research is conducted through its system of United States Department of Energy National Laboratories.

http://en.wikipedia.org/wiki/USDOE

3.1.2 About the National Energy Technology Laboratory (NETL)

The United States Department of Energy National Laboratories and Technology Centers are a system of facilities and laboratories overseen by the United States Department of Energy (DOE) for the purpose of advancing science and technology to fulfill the DOE mission. Sixteen of the 17 DOE national laboratories are federally funded research and development centers administered, managed, operated and staffed by private sector organizations under a Management and Operating (M&O) contract to DOE.

http://en.wikipedia.org/wiki/United_States_Department_of_Energy_National_Laboratories

3.1.3 Document Description

This 8-page document is a graphics rich brochure providing a broad overview of shale gas and its production as an energy source. Included information covers the following:

- Description of shale gas resources;
- Brief history of oil and gas development;
- Overview of the hydraulic fracturing process; and,
- Research and development efforts of the NETL.

3.2 Hydraulic Fracturing: How It Works

By: FracFocus, Interstate Oil & Gas Commission, and Interstate Oil and Gas Compact Commission

http://fracfocus.org/

3.2.1 About FracFocus

FracFocus is a webpage which provides the national hydraulic fracturing chemical registry and other industry related information.

FracFocus is managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, two organizations whose missions both revolve around conservation and environmental protection.

http://fracfocus.org/

3.2.2 About the Ground Water Protection Council

The Ground Water Protection Council (GWPC) is a nonprofit 501(c)6 organization whose members consist of state ground water regulatory agencies which come together within the GWPC organization to mutually work toward the protection of the nation's ground water supplies. The purpose of the GWPC is to promote and ensure the use of best management practices and fair but effective laws regarding comprehensive ground water protection.

Our mission is to promote the protection and conservation of ground water resources for all beneficial uses, recognizing ground water as a critical component of the ecosystem. We provide an important forum for stakeholder communication and research in order to improve governments' role in the protection and conservation of groundwater.

http://www.gwpc.org/about-us

3.2.3 About the Interstate Oil and Gas Commission

The Interstate Oil and Gas Compact Commission is a multi-state government agency that is passionate about advancing the quality of life for all Americans. However, without energy, the quality of life we enjoy today would not exist. That's why the Commission works to ensure our nation's oil and natural gas resources are conserved and maximized while protecting health, safety and the environment.

It's no secret that American energy is the most valuable to our nation. The responsible development of our own resources not only strengthens our economy by creating and maintaining jobs, but also lessens our dependence on foreign resources, making oil and natural gas more affordable for consumers.

The IOGCC advocates for environmentally-sound ways to increase the supply of American energy. We accomplish this by providing governors of member states with a clear and unified voice to Congress, while also serving as the authority on issues surrounding these vital resources.

The Commission also assists states in balancing a multitude of interests through sound regulatory practices. Our unique structure offers a highly effective forum for states, industry, Congress and the environmental community to share information and viewpoints to advance our nation's energy future. We stand dedicated to securing resources needed to ensure our nation's energy, economic and national security.

http://iogcc.org/about-us

3.2.4 Document Description

The “Frac Focus” document contained within the course material is a compilation of various portions of the Frac Focus webpage. While significant re-formatting of the material was implemented by Mr. Harper to facilitate this transition, the content is consistent with the original source. Although the primary purpose of the web page is to provide a national hydraulic fracturing chemical registry, extensive additional information, which is contained herein, also documents the following:

- Historical perspective;
- The hydraulic fracturing process;
- Chemical use in hydraulic fracturing; and,
- Frequently asked question.

3.3 Modern Shale Gas Development in the United States: A Primer

By: United States Department of Energy

http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf

3.3.1 About the USDOE

Please see Executive Summary, Section 3.1.1.

3.3.2 About the NETL

Please see Executive Summary, Section 3.1.2.

3.3.3 Document Description

This Primer on Modern Shale Gas Development in the United States intends to provide sound technical information on and additional insight into the relationship between today's fastest growing, and sometimes controversial, natural gas resource development activity, and environmental protection, especially water resource management. While conveying an accurate depiction of current factors, the document does not represent the view of any individual state and acknowledges that shale gas development will continue to evolve.

Specific topics documented within this document include the following:

- The importance of shale gas;
- Shale gas development in the United States;
- Regulatory Framework; and,
- Environmental considerations.

3.4 "Truthland" - An Energy Industry Documentary Response to the "Gasland" Movie

By: Independent Petroleum Association of America and Energy-in-Depth

http://www.truthlandmovie.com/

3.4.1 About the Independent Petroleum Association of America

The Independent Petroleum Association of America ("IPAA") is a national trade association headquartered in Washington, D.C. It serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the U.S. Congress, the Administration and federal agencies. IPAA provides economic and statistical information about the domestic exploration and production industry. IPAA also develops investment symposia and other opportunities for its members.

http://www.ipaa.org/

3.4.2 About Energy-in-Depth

Launched by the IPAA in 2009, Energy In Depth (EID) is a research, education and public outreach campaign focused on getting the facts out about the promise and potential of responsibly developing America's onshore energy resource base – especially abundant sources of oil and natural gas from shale and other "tight" reservoirs across the country. It's an effort that benefits directly from the support, guidance and technical insight of a broad segment of America's oil and natural gas industry, led in Washington by IPAA, but directed on the ground by our many affiliates — and IPAA's more than 6,000 members — in the states.

http://www.energyindepth.org/whats-eid/

3.4.3 Document Description

The "Truthland" document contained within the course material is a compilation of various portions of the Truthland webpage. While significant re-formatting of the material was implemented by Mr. Harper to facilitate this transition, the content is consistent with the original source.

In the HBO movie "Gasland", New York City filmmaker Josh Fox tried to scare people into thinking that natural gas development and hydraulic fracturing are new, unregulated, and dangerous. In response to Gasland, the Independent Petroleum Association of America and Energy-in-Depth developed their own film documentary called "Truthland". This film follows a Pennsylvanian mom, teacher, and farmer named Shelly, who after watching Gasland becomes concerned about the movie's claims.

3.5 Colorado Oil and Gas Conversation Commission Response to the "Gasland Movie"

By: Colorado Oil and Gas Conservation Commission

http://cogcc.state.co.us/Announcements/Hot_Topics/Hydraulic_Fracturing/GASLAND%20DOC.pdf

3.5.1 About the Colorado Oil and Gas Conservation Commission

The Colorado Oil and Gas Conservation Commission ("COGCC") is an Oklahoma state agency whose goal is to foster the responsible development of Colorado's oil and gas natural resources. Responsible development results in:

- The efficient exploration and production of oil and gas resources in a manner consistent with the protection of public health, safety and welfare;
- The prevention of waste;
- The protection of mineral owners' correlative rights; and,
- The prevention and mitigation of adverse environmental impacts.

The COGCC seeks to serve, solicit participation from, and maintain working relationships with all those having an interest in Colorado's oil and gas natural resources.

http://cogcc.state.co.us/

3.5.2 Document Description

A October 29, 2010 memorandum by the COGCC, which corrects errors in the Gasland movie's portrayal of several Colorado incidents. Additionally, the following COGCC link provides access to additional hydraulic fracturing information.

http://cogcc.state.co.us/Announcements/Hot_Topics/Hydraulic_Fracturing/Hydra_Frac_topics.html

4.0 Current Hydraulic Fracturing Practices – Overview of the "Neutral Documentation"

4.1 Hydraulic Fracturing

By: Wikipedia, the free encyclopedia

http://en.wikipedia.org/wiki/Hydraulic_fracturing

4.1.1 About Wikipedia

Wikipedia is a collaboratively edited, multilingual, free Internet encyclopedia that is supported by the non-profit Wikimedia Foundation. Volunteers worldwide collaboratively write Wikipedia's 30 million articles in 287 languages, including over 4.4 million in the English Wikipedia. Anyone who can access the site can edit almost any of its articles, which on the Internet comprise the largest and most popular general reference work, ranking sixth globally among all websites on Alexa with an estimated 365 million readers.

http://en.wikipedia.org/wiki/Wikipedia

4.1.2 Document Description

The "Wikipedia" document contained within the course material is a summation of the Wikipedia webpage on hydraulic fracturing. While significant re-formatting of the material was implemented by Mr. Harper to facilitate this transition, the content is consistent with the original source.

This Wikipedia article provides a comprehensive description of the hydraulic fracturing process and its potential impacts. Primary topics discussed include the following:

- Geology
- Hydraulic Fracturing Process
- Environmental Impacts
- Public Debates
- History
- Economic Impacts
- Health Impacts

4.2 Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources By: United States Environmental Protection Agency

http://www2.epa.gov/hfstudy

4.2.1 About the United States Environmental Protection Agency

The United States Environmental Protection Agency is an agency of the U.S. federal government which was created for the purpose of protecting human health and the environment by writing and enforcing regulations based on laws passed by Congress. The EPA has its headquarters in Washington, D.C., regional offices for each of the agency's ten regions, and 27 laboratories. The agency conducts environmental assessment, research, and education. It has the responsibility of maintaining and enforcing national standards under a variety of environmental laws, in consultation with state, tribal, and local governments. It delegates some permitting, monitoring, and enforcement responsibility to U.S. states and the federal recognized tribes. EPA enforcement powers include fines, sanctions, and other measures. The agency also works with industries and all levels of government in a wide variety of voluntary pollution prevention programs and energy conservation efforts.

http://en.wikipedia.org/wiki/Epa

4.2.2 Document Description

At the request of Congress, EPA is conducting a study to better understand any potential impacts of hydraulic fracturing_on drinking water resources. The scope of the research includes the full lifespan of water in hydraulic fracturing. The progress report was released in December 2012 and a draft report is expected to be released for public comment and peer review in 2014.

What is the hydraulic fracturing water cycle?

5.0 Overview of the "Non-Favorable Documentation"

5.1 Environmental Impacts of Hydraulic Fracturing

By: Earthworks

http://www.earthworksaction.org/issues/detail/hydraulic_fracturing_101#.UvK_vPldXNs

5.1.1 About Earthworks

- Earthworks is a nonprofit organization dedicated to protecting communities and the environment from the impacts of irresponsible mineral and energy development while seeking sustainable solutions.
- Earthworks stands for clean water, healthy communities and corporate accountability. We're working for solutions that protect both the Earth's resources as well as our communities.
- Earthworks fulfills it's mission by working with communities and grassroots groups to reform government policies, improve corporate practices, influence investment decisions and encourage responsible materials sourcing and consumption.
- Earthworks exposes the health, environmental, economic, social and cultural impacts of mining and energy extraction through work informed by sound science.

http://www.earthworksaction.org/about

5.1.2 Document Description

The "Environmental Impacts of Hydraulic Fracturing" document contained within the course material is a compilation of various portions of the Earthworks webpage. While significant re-formatting of the material was implemented by Mr. Harper to facilitate this transition, the content is consistent with the original source.

This Earthworks article provides a comprehensive description of the hydraulic fracturing process and its potential impacts. Primary topics discussed include the following:

- Overview
- Water Use
- Sand and Proppants
- Toxic Chemicals
- Health Concerns
- Surface Water and Soil Contamination
- Groundwater Contamination
- Air Quality
- Waste Disposal
- Chemical Disclosure
- "Halliburton Loophole"
- Myths & Facts

5.2 The Oil and Gas Industry's Exclusions and Exemptions to Major Environmental Statutes

By: Earthworks / Oil & Gas Accountability Project

http://www.earthworksaction.org/library/detail/the_oil_and_gas_industrys_exclusions_and_exemptions_to_major_environmental_#.UvmiWPldXNs

5.2.1 About Earthworks

Please see Executive Summary, Section 5.1.1.

5.2.2 About Oil & Gas Accountability Project

Earthworks' Oil & Gas Accountability Project serves drilling impacted communities around the country by working to reform government policies at the federal, state and local levels.

- Proposed Federal Reforms: Closing gaps in federal environmental oversight, like the Halliburton loophole in Clean Water Act, or the drilling exemption in the Resources Conservation and Recovery Act.
- Proposed State Reforms:
  - Improving landowner protections – as done in Colorado and New Mexico
  - Strengthening environmental protections – as done with the "pitless" rule in New Mexico
  - Strengthening public health oversight – as done in Dish & Wilma Subra, TX by prodding the Texac Commission on Environmental Quality into quicker reactions to drilling air pollution complaints.

http://www.earthworksaction.org/reform_governments/oil_gas_accountability_project

5.2.3 Document Description

"The Oil and Gas Industry's Exclusions and Exemptions to Major Environmental Statutes" documents the oil and gas industry's sweeping exemptions from provisions in the major federal environmental statutes intended to protect human health and the environment. These statutes include the:

- Comprehensive Environmental Response, Compensation, and Liability Act
- Resource Conservation and Recovery Act
- Safe Drinking Water Act

- Clean Water Act
- Clean Air Act
- National Environmental Policy Act
- Toxic Release Inventory under the Emergency Planning and Community Right-to-Know Act

5.3 "Gasland" I & II – The Movies

By: Gasland

http://one.gaslandthemovie.com/

5.3.1 About "Gasland"

The largest domestic natural gas drilling boom in history has swept across the United States. The Halliburton-developed drilling technology of "fracking" or hydraulic fracturing has unlocked a "Saudia Arabia of natural gas" just beneath us. But is fracking safe? The Gasland movie series and webpage investigate this important question.

5.3.2 Document Description

The "Gasland" I & II document contained within the course material is a compilation of various portions of the Gasland webpage. While significant re-formatting of the material was implemented by Mr. Harper to facilitate this transition, the content is consistent with the original source.

Gasland I: In May 2008, Josh Fox received a letter from a natural gas company offering to lease his family's land in Milanville, Pennsylvania for $100,000 to drill for gas. Fox then set out to see how communities are being affected in the west where a natural gas drilling boom has been underway for the last decade. He spent time with citizens in their homes and on their land as they relayed their stories of natural gas drilling in Colorado, Wyoming, Utah and Texas, among others. He spoke with residents who have experienced a variety of chronic health problems directly traceable to contamination of their air, of their water wells or of surface water. In some instances, the residents are reporting that they obtained a court injunction or settlement monies from gas companies to replace the affected water supplies with potable water or water purification kits.

Throughout the documentary, Fox reached out to scientists, politicians and gas industry executives and ultimately found himself in the halls of Congress as a subcommittee was discussing the Fracturing Responsibility and Awareness of Chemicals Act, "a bill to amend the Safe Drinking Water Act to repeal a -certain exemption for hydraulic fracturing." Hydraulic fracturing was exempted from the Safe Drinking Water Act in the Energy Policy Act of 2005.

Gasland Part II: This movie premiered at the 2013 Tribeca Film Festival, shows how the stakes have been raised on all sides in one of the most important environmental issues facing our nation today. The film argues that the gas industry's portrayal of natural gas as a clean and safe alternative to oil is a myth and that fracked wells inevitably leak over time, contaminating water and air, hurting families, and endangering the earth's climate with the potent greenhouse gas, methane. In addition the film looks at how the powerful oil and gas industries are in Fox's words "contaminating our democracy".

5.4 Fracking – Gas Drilling's Environmental Threat

By: ProPublica

http://www.propublica.org/

5.4.1 About "ProPublica"

ProPublica is an independent, non-profit newsroom that produces investigative journalism in the public interest. Their work focuses exclusively on truly important stories, stories with "moral force." They do this by producing journalism that shines a light on exploitation of the weak by the strong and on the failures of those with power to vindicate the trust placed in them.

Investigative journalism is at risk. Many news organizations have increasingly come to see it as a luxury. Today's investigative reporters lack resources: Time and budget constraints are curbing the ability of journalists not specifically designated "investigative" to do this kind of reporting in addition to their regular beats. New models are, therefore, necessary to carry forward some of the great work of journalism in the public interest that is such an integral part of self-government, and thus an important bulwark of our democracy.

The Mission: To expose abuses of power and betrayals of the public trust by government, business, and other institutions, using the moral force of investigative journalism to spur reform through the sustained spotlighting of wrongdoing.

5.4.2 Document Description

The "Fracking – Gas Drilling's Environmental Threat" document contained within the course material is a compilation of various portions of the ProPublica webpage. While significant re-formatting of the material was implemented by Mr. Harper to facilitate this transition, the content is consistent with the original source.

This ProPublica document provides a compilation of numerous investigative journalism articles which document hydraulic fracturing processes and their potential impacts.

6.0 Future Hydraulic Fracturing Practices – Waterless

The "future" of fracking involves "waterless" fracking. In short, most of the environmental adverse effects are eliminated while the gas recovery process is still effective. Currently, it just costs a bit more…

While there are numerous articles that document the "waterless" fracking process, the one provided herein is current and a quality representation of the overall group.

Reference*: "A New Way of Fracking", Science and Technology magazine, May 12, 2014.*

Shale Gas: *Applying Technology to Solve America's Energy Challenges*

The United States enjoys a rich complement of natural resources, including substantial quantities of fossil fuels—crude oil, coal, and natural gas. These energy sources have helped to fuel our Nation's growth and development for the past two hundred years.

The presence of natural gas—primarily methane—in the shale layers of sedimentary rock formations that were deposited in ancient seas has been recognized for many years. The difficulty in extracting the gas from these rocks has meant that oil and gas companies have historically chosen to tap the more permeable sandstone or limestone layers which give up their gas more easily.

Shale gas well on a Pennsylvania farm. (Photos courtesy of Range Resources)

But American ingenuity and steady research have led to new ways to extract gas from shales, making hundreds of trillions of cubic feet of gas technically recoverable where they once were not.

New technologies are also being applied to make certain that the process of drilling for this valuable resource minimizes environmental impacts.

U.S. DEPARTMENT OF ENERGY | NETL

Barnett shale well at urban location (Courtesy of Chesapeake Energy)

Fayetteville shale well (Courtesy of Southwestern Energy)

This resource's availability to the American people could not have come at a better time. The calls for reducing our reliance on foreign energy supplies, for reducing our contribution of carbon dioxide to the atmosphere, and for increasing economic growth and wealth creation, can all be met, at least in part, by the development of shale gas. The U.S. Department of Energy (DOE), through the National Energy Technology Laboratory (NETL), has played a historic role in helping to advance the technology that is making shale gas production possible.

This map, available from the U.S. Energy Information Administration (EIA) at http://www.eia.doe.gov, shows the location and extent of the major shale plays (e.g., Marcellus shale) and the sedimentary basins (regions with thick layers of sedimentary rock containing fossil fuels) where these shale plays are found.

The Resource

Where shale gas comes from

About 360–415 million years ago, during the Devonian Period of Earth's history, the thick shales from which we are now producing natural gas were being deposited as fine silt and clay particles at the bottom of relatively enclosed bodies of water. At roughly the same time, primitive plants were forming forests on land and the first amphibians were making an appearance. Some of the methane that formed from the organic matter buried with the sediments escaped into sandy rock layers adjacent to the shales, forming conventional accumulations of natural gas which were relatively easy to extract. But some of it remained locked in the tight, low permeability shale layers.

This map of what geologists believe the land looked like 385 million years ago (during the Middle Devonian period) shows the outlines of today's states, and the bodies of water that created the Michigan, Appalachian, and Illinois basins can be seen. (Courtesy Prof. Ron Blakey, Northern Arizona University)

History of development

The shale gas timeline includes a number of important milestones:

Photo credit Drake Well Museum

1821 – First U.S. commercial natural gas well in Fredonia, New York, produces gas from shale.

1859 – Edwin Drake demonstrates that oil can be produced in large volumes, launching the U.S. oil industry.

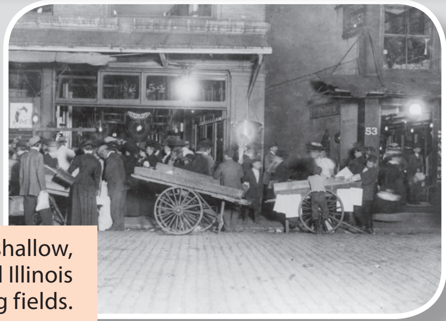


Photo credit Library of Congress

1860s to 1920s – Natural gas, including gas produced from shallow, low pressure, fractured shales in the Appalachian and Illinois basins, is limited to use in cities close to producing fields.

1930s – Technology developed to lay large diameter pipelines makes transmission of large volumes of gas from midcontinent and southeastern oil fields to northeastern cities possible; the natural gas industry grows exponentially.

Photo credit Ohio Historical Society

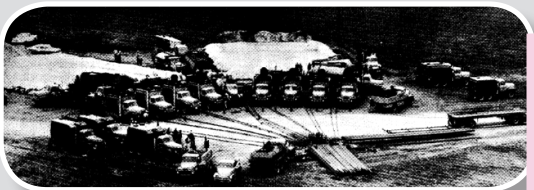


Photo credit Pennwell

Late 1940s – Hydraulic fracturing first used to stimulate oil and gas wells. The first hydraulic fracturing treatment (not shown here) was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in Grant County, Kansas.

Early 1970s – Development of downhole motors, a key component of directional drilling technology, accelerates. Directional drilling capabilities continue to advance for the next three decades.

Late 1970s and early 1980s – Fear that U.S. natural gas resources are dwindling prompts federally sponsored research to develop methods to estimate the volume of gas in "unconventional natural gas reservoirs" such as gas shales, tight sandstones and coal seams, and to improve ways to extract the gas from such rocks. Deeper buried shales, such as the Barnett in Texas and Marcellus in Pennsylvania, are known but believed to have essentially zero permeability and thus are not considered economic.

1980s to early 1990s – Mitchell Energy combines larger fracture designs, rigorous reservoir characterization, horizontal drilling, and lower cost approaches to hydraulic fracturing to make the Barnett Shale economic.

2003 to 2004 – Gas production from the Barnett Shale play overtakes the level of shallow shale gas production from historic shale plays like the Appalachian Ohio Shale and Michigan Basin Antrim plays. About 2 billion cubic feet (Bcf) of gas per day are produced from U.S. shales.

Photo credit Pennwell

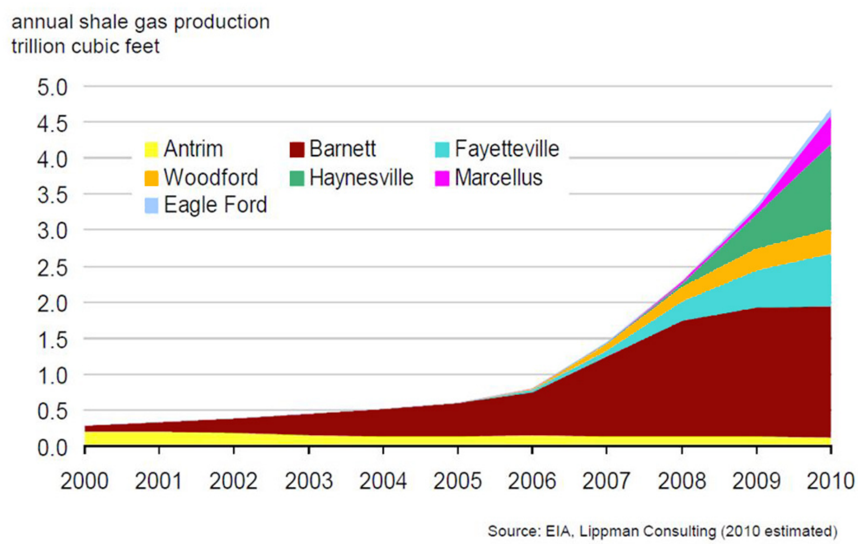
2005 to 2010 – Gas production from Barnett Shale grows to about 5 Bcf per day. Development of other major shale plays begins in other major basins.

2010 – The Marcellus shale underlies a significant portion of the mid-Atlantic/NE region—close to East Coast metropolitan natural gas demand centers—and is thought to contain nearly half of the technically recoverable shale gas resource.

Production trend

Shale gas production continues to increase. In 2009 it amounted to more than 8 Bcf per day, or about 14 % of the total volume of dry natural gas produced in the United States and about 12% of the natural gas consumed in the United States. Production from the Barnett Shale has leveled off, but volumes of gas from the Marcellus, Haynesville, Fayetteville and Woodford shales are growing as more wells are drilled in these plays and as other emerging plays are developed. The EIA projects that the shale gas share of U.S. natural gas production will continue to grow, reaching 45% of the total volume of gas produced in the United States by 2035.

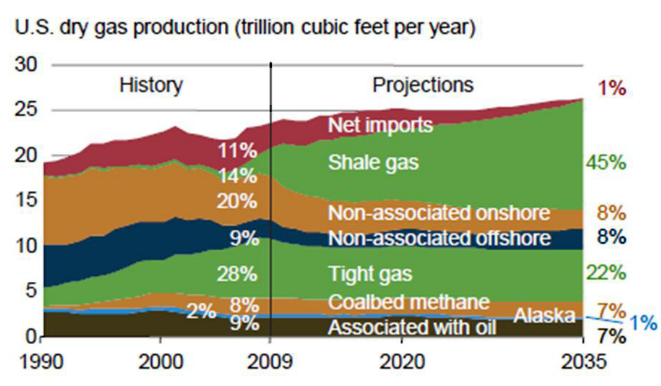
Core from organic Devonian shale formation



What it means for us

The EIA projects that there are 827 trillion cubic feet (Tcf) of natural gas that are recoverable from U.S. shales using currently available technology. The United States currently consumes about 23 Tcf per year, of which we produce about 20 Tcf and import the rest, so the shale gas resource alone represents about 36 years of current consumption. One Tcf of natural gas is enough to heat 15 million homes for 1 year, generate 100 billion kilowatt-hours of electricity, or fuel 12 million natural-gas-fired vehicles for 1 year.

Developing domestic natural gas resources means additional jobs (economic growth) when wells are drilled, pipelines are constructed, and production facilities are built and operated. In addition, higher volumes of available domestic natural gas mean lower fuel or feedstock prices for industries that use natural gas to process or manufacture products. This means fewer jobs lost to lower-cost overseas competitors, as well as lower prices for consumers.



The EIA's Annual Energy Outlook for 2011 shows the contribution of shale gas to U.S. natural gas production reaching 45% by 2035.

Shale gas production also means increased tax and royalty receipts for state and federal government, and increased economic activity in producing areas from royalty and bonus payments to landowners. This influx of revenue can be used to enhance public services.

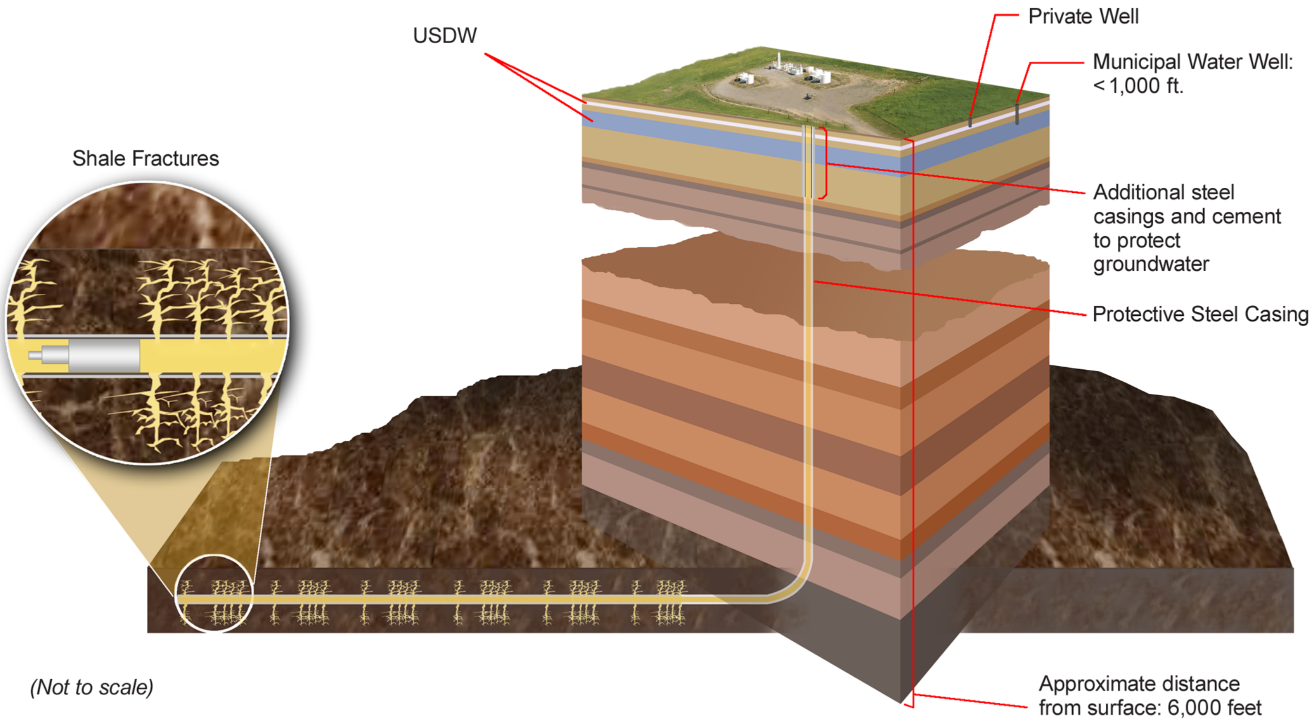
The Technology

How it works

Wells are drilled vertically to intersect the shale formations at depths that typically range from 6,000 to more than 14,000 feet. Above the target depth the well is deviated to achieve a horizontal wellbore within the shale formation, which can be hundreds of feet thick. Wells may be oriented in a direction that is designed to maximize the number of natural fractures present in the shale intersected. These natural fractures can provide pathways for the gas that is present in the rock matrix to flow into the wellbore. Horizontal wellbore sections of 5,000 feet or more may be drilled and lined with metal casing before the well is ready to be hydraulically fractured.

Hydraulic fracturing

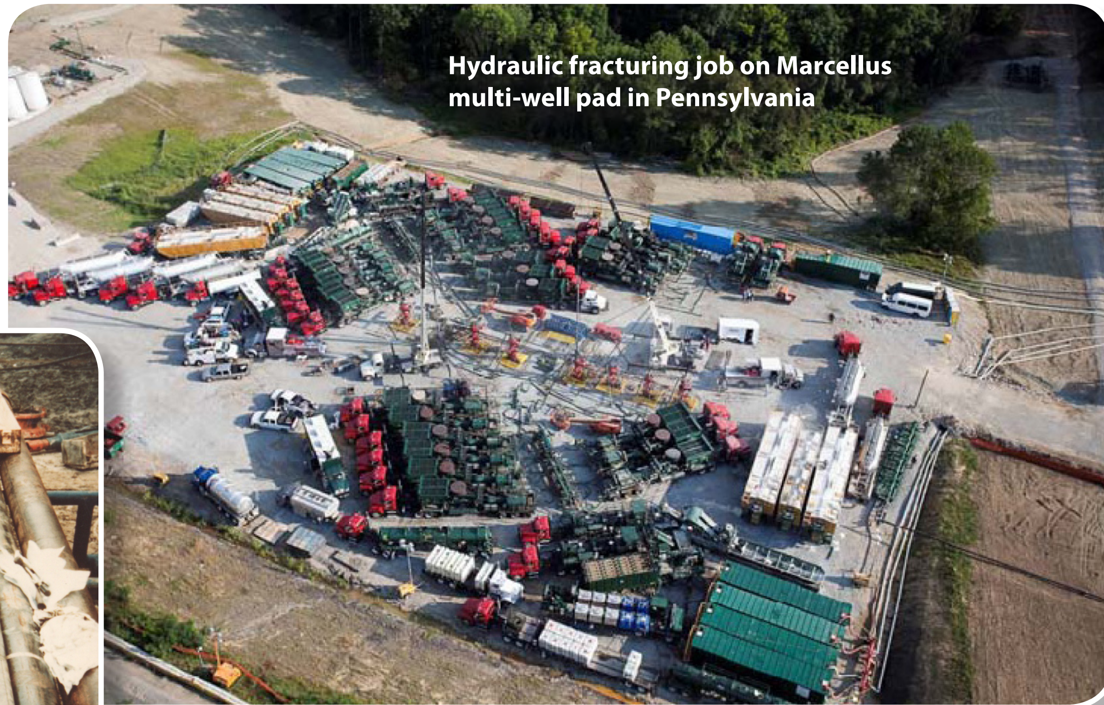
Beginning at the toe of the long horizontal section of the well, segments of the wellbore are isolated, the casing is perforated, and water is pumped under high pressure (thousands of pounds per square inch) through the perforations, cracking the shale and creating one or more fractures that extend out into the surrounding rock. These fractures continue to propagate, for hundreds of feet or more, until the pumping ceases. Sand carried along in the water props open the fracture after pumping stops and the pressure is relieved. The propped fracture is only a fraction of an inch wide, held open by these sand grains. Each of these fracturing stages can involve as much as 10,000 barrels (420,000 gallons) of water with a pound per gallon of sand. Shale wells have as many as 25 fracture stages, meaning that more than 10 million gallons of water may be pumped into a single well during the completion process. A portion of this water is flowed back immediately when the fracturing process is completed, and is reused. Additional volumes return over time as the well is produced.



Steel casing lines the well and is cemented in place to prevent any communication up the wellbore as the fracturing job is pumped or the well is produced. Shallow formations holding fresh water that may be useful for farming or public consumption are separated from the fractured shale by thousands of feet of rock.

NETL's early contributions

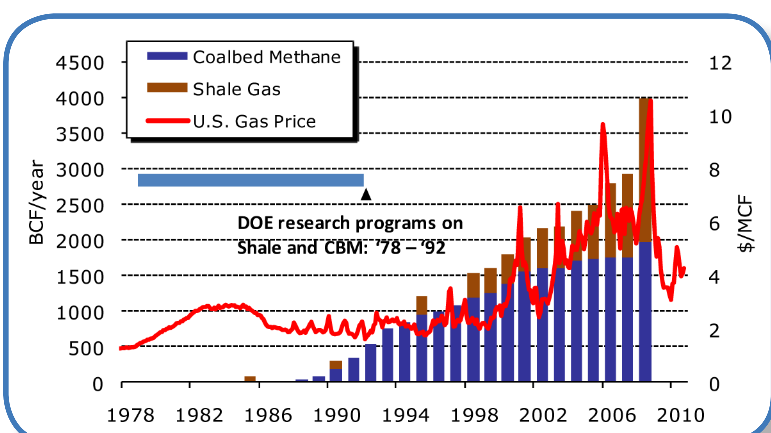
In the 1970s, fears of dwindling domestic natural gas supplies spurred DOE researchers to examine alternative sources of natural gas in unconventional reservoirs such as shales, coal seams, and tight sandstones. NETL helped to advance foam fracturing technology, oriented coring and fractographic analysis, and large-volume hydraulic fracturing. In 1975, a DOE-industry joint venture drilled the first Appalachian Basin directional wells to tap shale gas, and shortly thereafter completed the first horizontal shale well to employ seven individual hydraulically fractured intervals. DOE integrated basic core and geologic data from 35 research wells to prepare the first, publicly available estimates of technically recoverable gas for gas shales in West Virginia, Ohio, and Kentucky.



DOE researchers gathering data from one of a series of cored shale wells in the Appalachian Basin in the early 1980s.

DOE's important contributions to shale gas development have been recognized by many. According to Penn State University's Dr. Terry Engelder, a recognized expert on the Marcellus Shale, DOE's Eastern Gas Shales Research Program "helped expand the limits of gas shale production and increased understanding of production mechanisms. It is one of the great examples of value-added work led by the DOE." In his recent paper summarizing thirty years of gas shale fracturing, George E. King, Global Technology Consultant for Apache Corporation, states that "Technology developments in the North American Devonian shale during the late 1970s and proceeding into the 90s, chiefly from a loose alliance of the U.S. Department of Energy, the Gas Research Institute and numerous operators, combined to collectively produce several breakthroughs … horizontal wells, multi-stage fracturing and slick water fracturing." Fred Julander of Julander Energy, a 36-year independent producer and a member of the National Petroleum Council, has stated that "The Department of Energy was there with research funding when no one else was interested and today we are all reaping the benefits. Early DOE R&D in tight gas sands, gas shales, and coalbed methane helped to catalyze the development of technologies that we are applying today."

For example, EQT, an independent producer in Pittsburgh, PA, has been developing the Huron Shale in Eastern KY using air drilling technology that relies on electromagnetic telemetry (EMT) to directionally drill horizontal wellbores. EQT reports that it is currently producing more than 100 million cubic feet per day (MMcfd) from its Huron wells and believes the resource potential could be as much as 10 Tcf of gas equivalent. The EMT technology now offered by Sperry Drilling (a Halliburton service line) has its roots in DOE research from the 1980s and 90s. "In the early 1980s, the industry as a whole did not have a clear vision for producing gas from shales and benefited from DOE involvement and funding of EMT technology… there is a clear line of sight between the initial research project and the commercial EMT service available today," states Dan Gleitman, Sr. Director – Intellectual Asset Management, Halliburton.



DOE research during the 1980s played a role in the growth of unconventional gas production that is now helping to reduce the price of natural gas to consumers

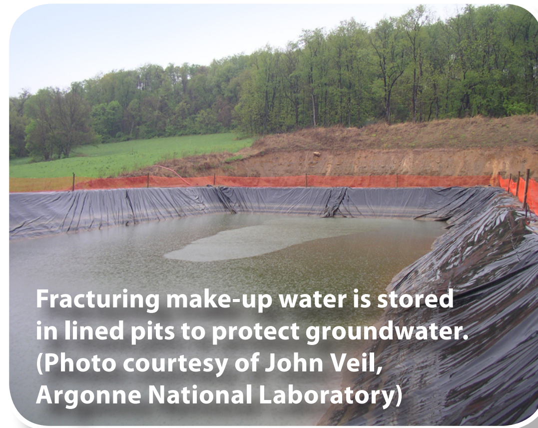
While decades of technological enhancements stand behind the suite of tools and methodologies that make shale gas production possible, publicly funded R&D has played an important role. NETL continues to manage a suite of research projects focused on increasing the supply of domestic natural gas to the consumer, in an environmentally sustainable and increasingly safe manner.

What's Next

What DOE is doing now

Currently, NETL is actively involved in advancing technologies that can help producers develop shale gas resources in the most environmentally responsible manner. Research is under way to find improved ways to treat fracture flowback water so that it can be reused or easily disposed of and to reduce the "footprint" of shale gas operations so that there is less disruption of the surface during drilling and completion operations.

DOE is refocusing the work done under Section 999 (Subtitle J) of the Energy Policy Act of 2005 on safety, environmental sustainability, and quantifying the risks of exploration and production activity.



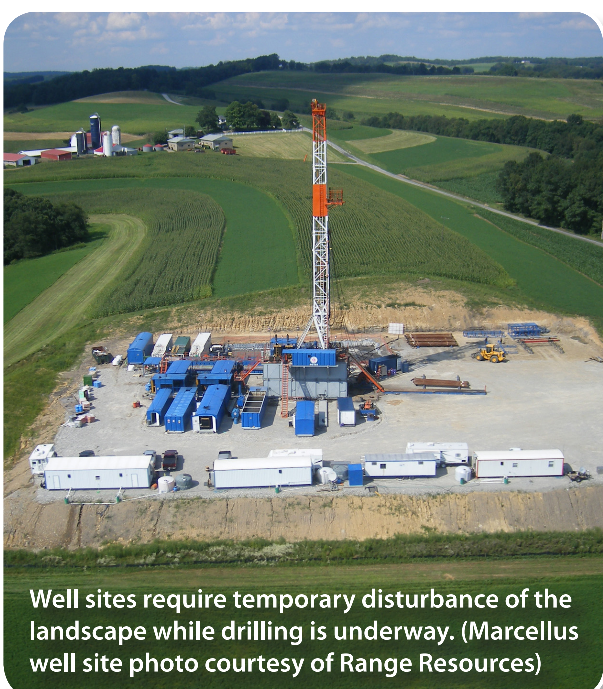
Fracturing make-up water is stored in lined pits to protect groundwater. (Photo courtesy of John Veil, Argonne National Laboratory)

Fracturing trucks on location at a Pennsylvania Marcellus location. (Photo courtesy of John Veil, Argonne National Laboratory)

DOE is working closely with the U.S. Environmental Protection Agency (EPA) as it carries out an exhaustive study to quantify the potential risk of hydraulic fracturing to underground sources of drinking water. NETL is also collaborating with the Department of Interior to enhance understanding of these risks.

Recent years have witnessed a number of initiatives to address the challenges of producing shale gas, sponsored by states, environmental groups, industry advocacy groups, and research organizations. DOE is exploring creation of a Shale Gas Initiative, in cooperation with public, private and non-governmental stakeholders, to build on these efforts and identify "best practices" that could be used by both operators and regulatory agencies to raise the bar on safety and environmental sustainability during shale gas development.

The U.S. Department of State has launched a U.S.-China Shale Gas Resource Initiative to help reduce greenhouse gas emissions, promote energy security and create commercial opportunities for U.S. companies. To date, the effort has engaged hundreds of Chinese technologists, facilitated a Chinese delegation's visit to a U.S. shale gas development operation, and created interest in American unconventional gas technologies through forums and workshops.



Well sites require temporary disturbance of the landscape while drilling is underway. (Marcellus well site photo courtesy of Range Resources)

DOE has worked with states through the Ground Water Protection Council (GWPC) to develop and maintain the Risk-Based Data Management System (RBDMS). Nationwide, 20 states and one Indian Nation now use the RBDMS to help operators comply with regulations. DOE has recently enhanced the RBDMS to track and record data related to hydraulic fracturing treatments. DOE has also funded in part, a Hydraulic Fracturing Chemical Registry to be hosted by the GWPC and Interstate Oil and Gas Compact Commission (IOGCC). This website will be a means for the industry to voluntarily supply hydraulic fracturing chemical data in a consistent and centralized location.

In 2009, DOE teamed with IOGCC to form a Shale Gas Directors Task Force to serve as a forum for states to share insights on issues and innovations related to shale gas development at the local, state and federal levels. More information is available at www.iogcc.org and http://groundwork.iogcc.org.

While it will be impossible to extract shale gas without some temporary disruption to the rural landscape, new and existing technologies can be employed to limit this disruption, to mitigate any surface impacts, and to minimize impacts to other natural resources in the process.

Where to find out more

You can find out more about shale gas from these resources:

- **NETL website –** The National Energy Technology Laboratory has a complete list of research projects, with details about objectives, accomplishments, expected benefits and results, at http://www.netl.doe.gov/.

- **DOE website –** The Department of Energy has information available on Department objectives and accomplishments related to natural gas at http://energy.gov/energysources/naturalgas.htm.

- **Marcellus Shale Coalition website –** This website has general information provided by an organization "committed to the responsible development of natural gas from the Marcellus Shale geological formation and the enhancement of the region's economy that can be realized by this clean-burning energy source" at http://marcelluscoalition.org/home/.

- **Groundwork –** The IOGCC website focuses on shale gas regulatory information at http://groundwork.iogcc.org.

- **Publications –** A number of publications have been produced by NETL and others that help to explain shale gas and the technologies involved. These include:
  - "Modern Shale Gas Development in the United States – A Primer," available for download at http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf
  - NETL's "E & P Focus Newsletter" provides updates on various shale gas research projects, available for download at http://www.netl.doe.gov/technologies/oil-gas/ReferenceShelf/epfocus.html
  - "An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play," available for download at http://www.alleghenyconference.org/PDFs/PELMisc/PSUStudyMarcellusShale072409.pdf
  - "The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update," available for download at http://marcelluscoalition.org/wp-content/uploads/2010/05/PA-Marcellus-Updated-Economic-Impacts-5.24.10.3.pdf
  - "Developing the Marcellus Shale," available for download at http://www.pecpa.org/sites/pecpa.org/files/downloads/Developing_the_Marcellus_Shale_0.pdf
  - "Water Resources and Natural Gas Production from the Marcellus Shale," available for download at http://pubs.usgs.gov/fs/2009/3032/
  - "Homegrown Energy: The Facts About Natural Gas Exploration of the Marcellus Shale," available for download at http://www.marcellusfacts.com/pdf/homegrownenergy.pdf
  - "The Future of Natural Gas: An Interdisciplinary MIT Study," available for download at http://web.mit.edu/mitei/research/studies/naturalgas.html

- **Contacts –** Questions about DOE's shale gas research? Contact the following individuals for answers:
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    george.guthrie@netl.doe.gov

Hydraulic Fracturing:

How It Works

BY:

FracFocus
Chemical Disclosure Registry

GROUNDWATER PROTECTION COUNCIL

INTERSTATE OIL & GAS COMPACT COMMISSION

HYDRAULIC FRACTURING: HOW IT WORKS
BY FRAC FOCUS

TABLE OF CONTENTS

SECTION **DESCRIPTION** **PAGE**

LISTING OF FIGURES

LISTING OF TABLES

NOTES

- This document is a compilation of various portions of the Frac Focus webpage. While significant re-formatting of the material has occurred to facilitate this transition, the content is consistent with the original source.
- Hyperlinks are imbedded within the document and indicated by blue font color.
- Hyperlinks followed by the ‡ symbol lead to webpages outside of FracFocus.

HYDRAULIC FRACTURING: HOW IT WORKS
BY FRAC FOCUS

1.0 ABOUT FRAC FOCUS

FracFocus is the national hydraulic fracturing chemical registry and is managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, two organizations whose missions both revolve around conservation and environmental protection.

The site was created to provide the public access to reported chemicals used for hydraulic fracturing within their area. To help users put this information into perspective, the site also provides objective information on hydraulic fracturing, the chemicals used, the purposes they serve and the means by which groundwater is protected.

The primary purpose of this site is to provide factual information concerning hydraulic fracturing and groundwater protection. It is not intended to argue either for or against the use of hydraulic fracturing as a technology. It is also not intended to provide a scientific analysis of risk associated with hydraulic fracturing. While FracFocus is not intended to replace or supplant any state governmental information systems it is being used by a number of states as a means of official state chemical disclosure. Currently, ten states: Colorado, Oklahoma, Louisiana, Texas, North Dakota, Montana, Mississippi, Utah, Ohio and Pennsylvania use Fracfocus in this manner. Finally, this site does not deal with issues unrelated to chemical use in hydraulic fracturing such as Naturally Occurring Radioactive Material (NORM). This topic is beyond the current scope of this site.

FracFocus is a dynamic website that will evolve and expand over time. We welcome your comments and suggestions regarding the site. You can submit a comment or suggestion regarding this website from the Ask a Question page. The chemical data presented on this site has been submitted on a voluntary or regulatory basis by the participating oil and gas companies listed on the Links page who have agreed to disclose the information in the public interest. We hope you will find this site useful and informative.

Important Notes:

1. Participating companies have agreed to post records of wells fractured after the later of the date they registered to participate or January 1, 2011. Over the first full year of operation from April 11, 2011 to April 11, 2012 the FracFocus system recorded over 15,000 disclosures from a total of 231 participating companies. During the same period the FracFocus website had been visited more than 210,000 by over 145,000 individuals.
2. Questions about the fracturing of a specific well should be directed to the company whose name appears in the header of the fracturing record.
3. The listing of a chemical as proprietary on the fracturing record is based on the "Trade Secret ‡" provisions related to Material Safety Data Sheets (MSDS) found on the above link at 1910.1200(i)(1).

2.0 A HISTORIC PERSPECTIVE

Hydraulic fracturing is not new. The first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil or gas likely occurred in either the Hugoton field of Kansas in 1946 or near Duncan Oklahoma in 1949. In the ensuing sixty plus years, the use of hydraulic fracturing has developed into a routine technology that is frequently used in the completion of gas wells, particularly those involved in what's called "unconventional production," such as production from so-called "tight shale" reservoirs. The process has been used on over 1 million producing wells. As the technology continues to develop and improve, operators now fracture as many as 35,000 wells of all types (vertical and horizontal, oil and natural gas) each year.

Hydraulic Fracturing Job Circa 1950

Figure 1:

Hydraulic fracturing has had an enormous impact on America's energy history, particularly in recent times. The ability to produce more oil and natural gas from older wells and to develop new production once thought impossible has made the process valuable for US domestic energy production. Without hydraulic fracturing, as much as 80 percent of unconventional production from such formations as gas shales would be, on a practical basis, impossible.

3.0 HYDRAULIC FRACTURING: THE PROCESS

3.1 What Is Hydraulic Fracturing?

Contrary to many media reports, hydraulic fracturing is not a "drilling process." Hydraulic fracturing is used after the drilled hole is completed. Put simply, hydraulic fracturing is the use of fluid and material to create or restore small fractures in a formation in order to stimulate production from new and existing oil and gas wells. This creates paths that increase the rate at which fluids can be produced from the reservoir formations, in some cases by many hundreds of percent.

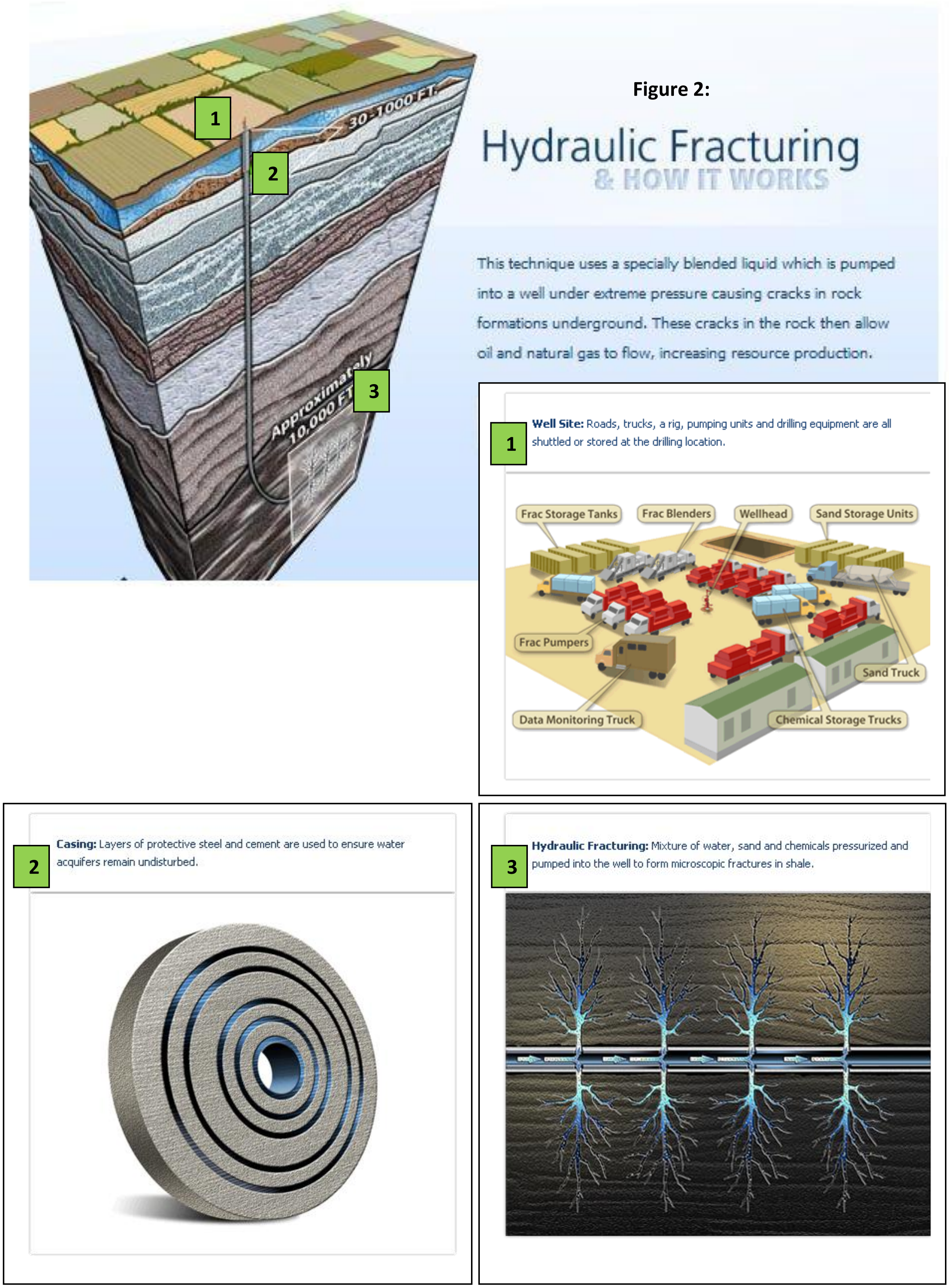
The process includes steps to protect water supplies. To ensure that neither the fluid that will eventually be pumped through the well, nor the oil or gas that will eventually be collected, enters the water supply, steel surface or intermediate casings are inserted into the well to depths of between 1,000 and 4,000 feet. The space between these casing "strings" and the drilled hole (wellbore), called the annulus, is filled with cement. Once the cement has set, then the drilling continues from the bottom of the surface or intermediate cemented steel casing to the next depth. This process is repeated, using smaller steel casing each time, until the oil and gas-bearing reservoir is reached (generally 6,000 to 10,000 ft). A more detailed look at casing and its role in groundwater protection is available HERE.

With these and other precautions taken, high volumes of fracturing fluids are pumped deep into the well at pressures sufficient to create or restore the small fractures in the reservoir rock needed to make production possible. Figure 2 depicts an overview of the hydraulic fracturing process.

3.2 What's in Hydraulic Fracturing Fluid?

Water and sand make up 98 to 99.5 percent of the fluid used in hydraulic fracturing. In addition, chemical additives are used. The exact formulation varies depending on the well. To view a chart of the chemicals most commonly used in hydraulic fracturing and for a more detailed discussion of this question, click HERE.

Figure 2:



Hydraulic Fracturing
& HOW IT WORKS
This technique uses a specially blended liquid which is pumped into a well under extreme pressure causing cracks in rock formations underground. These cracks in the rock then allow oil and natural gas to flow, increasing resource production.
30-1000 FT.
Approximately 10,000 FT
1
2
3
1
Well Site: Roads, trucks, a rig, pumping units and drilling equipment are all shuttled or stored at the drilling location.
Frac Storage Tanks
Frac Blenders
Wellhead
Sand Storage Units
Frac Pumpers
Sand Truck
Data Monitoring Truck
Chemical Storage Trucks
2
Casing: Layers of protective steel and cement are used to ensure water acquifers remain undisturbed.
3
Hydraulic Fracturing: Mixture of water, sand and chemicals pressurized and pumped into the well to form microscopic fractures in shale.

3.3 Why is Hydraulic Fracturing Used?

Experts believe 60 to 80 percent of all wells drilled in the United States in the next ten years will require hydraulic fracturing to remain operating. Fracturing allows for extended production in older oil and natural gas fields. It also allows for the recovery of oil and natural gas from formations that geologists once believed were impossible to produce, such as tight shale formations in the areas shown on the map below. Hydraulic fracturing is also used to extend the life of older wells in mature oil and gas fields.

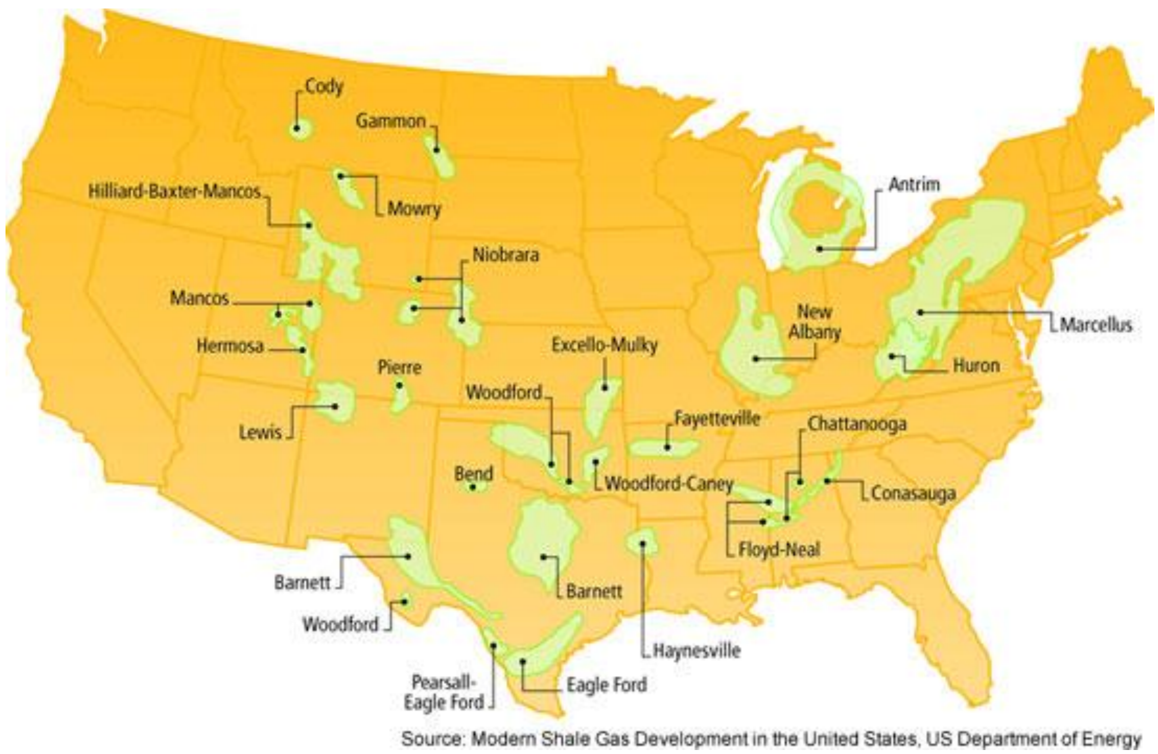


Figure 3: United States Shale Gas Formations

3.4 How is Hydraulic Fracturing Done?

The placement of hydraulic fracturing treatments underground is sequenced to meet the particular needs of the formation. The sequence noted below from a Marcellus Shale in Pennsylvania is just one example. Each oil and gas zone is different and requires a hydraulic fracturing design tailored to the particular conditions of the formation. Therefore, while the process remains essentially the same, the sequence may change depending upon unique local conditions. It is important to note that not all of the additives are used in every hydraulically fractured well; the exact "blend" and proportions of additives will vary based on the site-specific depth, thickness and other characteristics of the target formation.

1. An acid stage, consisting of several thousand gallons of water mixed with a dilute acid such as hydrochloric or muriatic acid, serves to clear cement debris in the wellbore and provide an open conduit for other frac fluids by dissolving carbonate minerals and opening fractures near the wellbore.
2. A pad stage, consisting of approximately 100,000 gallons of slickwater without proppant material, fills the wellbore with the slickwater solution (described below), opens the formation and helps to facilitate the flow and placement of proppant material.
3. A prop sequence stage, which may consist of several substages of water combined with proppant material (consisting of a fine mesh sand or ceramic material, intended to keep open, or "prop" the fractures created and/or enhanced during the fracturing operation after the pressure is reduced), may collectively use several hundred thousand gallons of water. Proppant material may vary from a finer particle size to a coarser particle size throughout this sequence.
4. A flushing stage, consisting of a volume of fresh water sufficient to flush the excess proppant from the wellbore.

Other additives commonly used in the fracturing solution employed in Marcellus wells include:

- A dilute acid solution, as described in the first stage, is used during the initial fracturing sequence. This cleans out cement and debris around the perforations to facilitate the subsequent slickwater solutions employed in fracturing the formation.
- A biocide or disinfectant is used to prevent the growth of bacteria in the well that may interfere with the fracturingoperation. Biocides typically consist of bromine-based solutions or glutaraldehyde.
- A scale inhibitor, such as ethylene glycol, is used to control the precipitation of certain carbonate and sulfate minerals.
- Iron control/stabilizing agents such as citric acid or hydrochloric acid, are used to inhibit precipitation of iron compounds by keeping them in a soluble form.
- Friction reducing agents, also described above, such as potassium chloride or polyacrylamide-based compounds, are used to reduce tubular friction and subsequently reduce the pressure needed to pump fluid into the wellbore. The additives may reduce tubular friction by 50 to 60%. These friction-reducing compounds represent the "slickwater" component of the fracing solution.
- Corrosion inhibitors, such as N,n-dimethyl formamide, and oxygen scavengers, such as ammonium bisulfite, are used to prevent degradation of the steel well casing.

- Gelling agents, such as guar gum, may be used in small amounts to thicken the water-based solution to help transport the proppant material.
- Occasionally, a cross-linking agent will be used to enhance the characteristics and ability of the gelling agent to transport the proppant material. These compounds may contain boric acid or ethylene glycol. When cross-linking additives are added, a breaker solution is commonly added later in the frac stage to cause the enhanced gelling agent to break down into a simpler fluid so it can be readily removed from the wellbore without carrying back the sand/ proppant material.

3.4.1 Fractures: Their orientation and length

Certain predictable characteristics or physical properties regarding the path of least resistance have been recognized since hydraulic fracturing was first conducted in the oilfield in 1947. These properties are discussed below:

3.4.2 Fracture orientation

Hydraulic fractures are formed in the direction perpendicular to the least stress. Based on experience, horizontal fractures will occur at depths less than approximately 2000 ft. because the Earth's overburden at these depths provides the least principal stress. If pressure is applied to the center of a formation under these relatively shallow conditions, the fracture is most likely to occur in the horizontal plane, because it will be easier to part the rock in this direction than in any other. In general, therefore, these fractures are parallel to the bedding plane of the formation.

As depth increases beyond approximately 2000 ft., overburden stress increases by approximately 1 psi/ft., making the overburden stress the dominant stress. This means the horizontal confining stress is now the least principal stress. Since hydraulically induced fractures are formed in the direction perpendicular to the least stress, the resulting fracture at depths greater than approximately 2000 ft. will be oriented in the vertical direction.

In the case where a fracture might cross over a boundary where the principal stress direction changes, the fracture would attempt to reorient itself perpendicular to the direction of least stress. Therefore, if a fracture propagated from deeper to shallower formations it would reorient itself from a vertical to a horizontal pathway and spread sideways along the bedding planes of the rock strata.

3.4.3 Fracture length / height

The extent that a created fracture will propagate is controlled by the upper confining zone or formation, and the volume, rate, and pressure of the fluid that is pumped. The confining zone will limit the vertical growth of a fracture because it either possesses sufficient strength or elasticity to contain the pressure of the injected fluids or an insufficient volume of fluid has been pumped. This is important because the greater the distance between the fractured formation and the USDW, the more likely it will be that multiple formations possessing the qualities necessary to impede the fracture will occur. However, while it should be noted that the length of a fracture can also be influenced by natural fractures or faults as shown in a study that included microseismic analysis‡ of fracture jobs conducted on three wells in Texas, natural attenuation of the fracture will occur over relatively short distances due to the limited volume of fluid being pumped and dispersion of the pumping pressure regardless of intersecting migratory pathways.

The following text and graphs are excerpts from an article written by Kevin Fisher of Pinnacle, a Halliburton Company for the July 2010 edition of the American Oil and Gas Reporter.

"The concerns around groundwater contamination raised by Congress are primarily centered on one fundamental question: Are the created fractures contained within the target formation so that they do not contact underground sources of drinking water? In response to that key concern, this article presents the first look at actual field data based on direct measurements acquired while fracture mapping more than 15,000 frac jobs during the past decade.

Extensive mapping of hydraulic fracture geometry has been performed in unconventional North American shale reservoirs since 2001. The microseismic and tiltmeter technologies used to monitor the treatments are well established, and are also widely used for nonoil field (*sic*) applications such as earthquake monitoring, volcano monitoring, civil engineering applications, carbon capture and waste disposal. Figures 1 and 2 are plots of data collected on thousands of hydraulic fracturing treatments in the Barnett Shale in the Fort Worth Basin in Texas and in the Marcellus Shale in the Appalachian Basin.

More fracs have been mapped in the Barnett than any other reservoir. The graph illustrates the fracture top and bottom for all mapped treatments performed in the Barnett since 2001. The depths are in true vertical depth. Perforation depths are illustrated by the red-colored band for each stage, with the mapped fracture tops and bottoms illustrated by colored curves corresponding to the counties where they took place.

The deepest water wells in each of the counties where Barnett Shale fracs have been mapped, according to United States Geological Survey (http://nwis.waterdata.usgs.gov/nwis‡), are illustrated by the dark blue shaded bars at the top of Figure 4. As can be seen, the largest directly measured upward growth of all of these mapped fractures still places the fracture tops several thousands of feet below the deepest known aquifer level in each county.

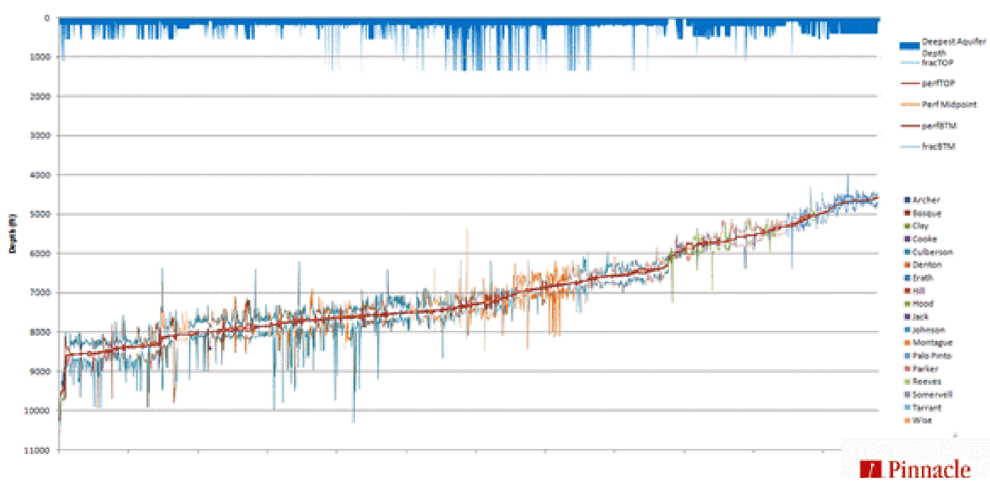


Figure 4: Barnett Mapped Frac Treatments / TVD

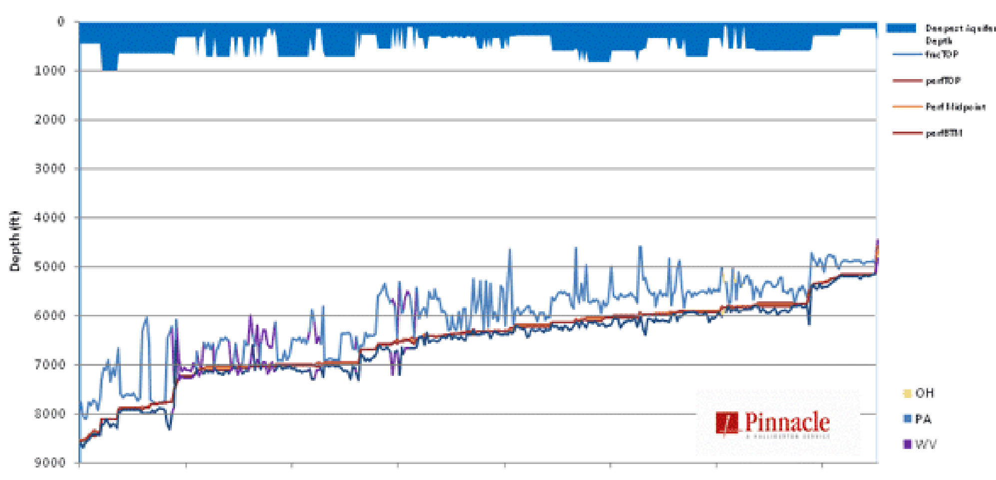


Figure 5: Marcellus Mapped Frac Treatments / TVD

The Marcellus data show a similarly large distance between the top of the tallest frac and the location of the deepest drinking water aquifers as reported in USGS data (dark blue shaded bars at the top of Figure 5). Because it is a newer play with fewer mapped frac stages at this point and encompasses several states, the data set is not as comprehensive as that from the Barnett. However, it is no less compelling in providing evidence of a very good physical separation between hydraulic fracture tops and water aquifers.

Almost 400 separate frac stages are shown, color coded by state. As can be seen, the fractures do grow upward quite a bit taller than in the Barnett, but the shallowest fracture tops are still ±4,500 feet, almost one mile below the surface and thousands of feet below the aquifers in those counties.

The results from our extensive fracture mapping database show that hydraulic fractures are better confined vertically (and are also longer and narrower) than conventional wisdom or models predict. Even in areas with the largest measured vertical fracture growth, such as the Marcellus, the tops of the hydraulic fractures are still thousands of feet below the deepest aquifers suitable for drinking water. The data from these two shale reservoirs clearly show the huge distances separating the fracs from the nearest aquifers at their closest points of approach, conclusively demonstrating that hydraulic fractures are not growing into groundwater supplies, and therefore, cannot contaminate them."

* Pennsylvania Department of Environmental Protection "Hydraulic Fracturing Overview." 07/20/2010. http://www.dep.state.pa.us/dep/deputate/minres/oilgas/new_forms/marcellus/Reports/DEP%20Fracing%20overview.pdf‡(4/11/2011).

3.4.4 Site Setup

Consistent with the Energy Policy Act of 2005, the U.S. Environmental Protection Agency (EPA) published a final rule in 2006 that exempts stormwater discharges of sediment from construction activities at oil and gas exploration and production operations from the requirement to obtain a National Pollutant Discharge Elimination System (NPDES)‡ stormwater permit as long as stormwater runoff to waters under the jurisdiction of the CWA are not contaminated with oil, grease, or hazardous substances. With this exemption, EPA specifically encouraged the oil and natural gas industry to develop and implement Best Management Practices (BMPs) to minimize the discharges of pollutants, including sediment, in stormwater both during and after construction activities. In an effort to meet the expectations of EPA under this rulemaking -- to incorporate successful voluntary stormwater management practices into day-to-day operations – the American Petroleum Institute (API) and the Independent Petroleum Association of America (IPAA), industry associations, and company representatives (referred to as the Stormwater Technical Workgroup (SWTW)), built upon the 2004 guidance document entitled Reasonable and Prudent Practices for Stabilization (RAPPS) of Oil and Natural Gas Construction Sites. Through field validation of the RAPPS, gap identification, and concerted program improvements, the SWTW developed a voluntary guidance document that, if implemented correctly, will serve as a readily applicable tool for operators to use in order to efficiently and effectively maximize control of stormwater discharges at oil and natural gas exploration and production activities throughout the contiguous U.S.

The construction of an oil and gas site is generally conducted using Best Management Practices similar to those listed in the RAPPS document and the EPA Construction Site Stormwater Runoff Contol website‡. This includes the construction of roads for the transport of heavy equipment such as the drill rig, leveling of the site, structures for erosion control, the excavation of pits to hold drilling fluids and drill cuttings, and the placement of racks to hold the drill pipe and casing strings. During the development of the site and hydraulic fracturing job, you can expect to see an increase in heavy traffic on the roads surrounding the site as equipment such as the drill rig, bulldozers, graders, water trucks and other heavy equipment is transported to and from the site. This traffic increase usually lasts a few weeks, and once well drilling, completion and fracturing are finished, should decrease substantially.

Figure 6: Typical Oil & Gas Hydraulic Fracturing Site Layout

Depending upon the specific conditions of the site and the nature of the drilling fluid, drill pits may or may not be used and may be lined with special liners to prevent fluid infiltration into the subsurface.

Once the well has been drilled and constructed and the drill rig removed, the site is prepared for well stimulation. The photo above shows the typical layout of a site that has been prepared for hydraulic fracturing. The surface facilities and layout typically involve a number of pieces of mobile equipment including fracture fluid storage tanks, sand storage units, chemical trucks, blending equipment and pumping equipment. All facets of the hydraulic fracturing job from the blending and pumping of the fracture fluids and proppants - solid material, usually sand, that is pumped into fractures to hold them open - to the way the rock formation responds to the fracturing, are managed from a single truck often referred to as the Data Monitoring Van.

3.5 Fracturing Fluid Management

3.5.1 Fluid Storage – "Pits"

From the time the first oil and gas wells were drilled, "pits" have been used to hold drilling fluids and wastes. Pits can be excavated holes in the ground, or they can be above ground containment systems such as steel tanks. Pits are used for storage of produced water, for emergency overflow, temporary storage of oil, burn off of waste oil, and for temporary storage of the fluids used to complete and treat the well.

The containment of fluids within a pit is the most critical element in the prevention of contamination of shallow ground water. The failure of a tank, pit liner, or the line carrying fluid ("flowline") can result in a release of contaminated materials directly into surface water and shallow ground water. Environmental clean-up of these accidentally released materials can be a costly and time consuming process. Therefore, prevention of releases is vitally important.

For pits constructed from ground excavation, pit lining may be necessary to prevent infiltration of fluids into the subsurface of the ground, depending upon the fluids being placed in the pit, the duration of the storage and the soil conditions. Typically, pit liners are constructed of compacted clay or synthetic materials like polyethylene or treated fabric that can be joined using special equipment.

Depending on the state, there are a number of other rules regarding pits and the protection of surface and ground water. In addition to liners, some states also require pits used for long term storage of fluids to be placed a minimum distance from surface water to minimize the chances of surface water contamination should there be an accidental discharge from the pits. In California, for example, pits may not be placed in areas considered "natural drainage channels". Some states also explicitly either prohibit or restrict the use of pits that intersect the water table.

New systems have been developed that avoid the use of pits. One technology that is becoming more common is closed loop fluid handling systems. These systems avoid the use of pits by keeping fluids within a series of pipes and tanks throughout the entire fluid storage process. Since fluid is never placed into contact with the ground, the likelihood of groundwater contamination is minimized.

3.5.2 Fluid Handling and Disposition

Following hydraulic fracturing, fluids returned to the surface within a specified length of time are referred to as flowback. Flowback can be comprised of as little as 3% and as much as 80% or more of the total amount of water and other material used to fracture the well. Besides the original fluid used for fracturing, flowback can also contain fluids and minerals that were in the fractured formation. Obviously, flowback water should be managed in a responsible manner.

The responsibility for regulating wastes such as flowback fluid lies with one or more state regulatory agencies, depending on the state. In at least 9 states, the jurisdiction over waste management for oil and gas exploration and production activity involves more than one agency.

Proper disposal of flowback fluids is critically important to the protection of both surface and ground water. The vast majority of flowback fluids are disposed of in underground injection wells. Injection of flowback fluids is conducted in a Class II injection well‡. Underground injection of flowback is regulated by either the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) program or by a state granted primary UIC enforcement authority by the EPA. At present there are 39 states, 2 tribes and 3 territories that have delegated authority from the EPA for the Class II (oil and gas related) injection well program. The remaining Class II UIC programs are managed by EPA regional offices.

While proper disposal of flowback fluids into permitted and monitored injection wells is currently the most effective means of safely isolating these fluids from the near-surface environment, the required specific geological conditions that are required for such wells do not exist in all areas. Depending upon where these areas are located, there may be other methods of handling flowback fluids such as treatment and discharge. Treatment of flowback can be conducted on-site or in centralized treatment facilities. If discharge is allowed under state or federal law, it must be done under strict controls which would typically require the issuance of a National Pollutant Discharge Elimination System (NPDES)‡ permit from a state or the federal environmental protection agency.

3.5.3 Fluid Recycling

Advances in flowback fluid treatment technology offer the promise of using flowback fluid for other purposes, rather than simply disposing of it. The use of filtration, reverse osmosis, decomposition in constructed wetlands, ion exchange and other technologies may eventually result in the widespread practice of using flowback fluids for such things as managed irrigation and land application. One practice in use today is the recycling of flowback fluids for their reuse in other hydraulic fracturing jobs, which saves water. This technology is being used by companies like Devon Energy in the Barnett shale area around Ft. Worth, Texas. Several companies also use this technology in the Marcellus shale play in Pennsylvania.

The following chart below shows the typical flowback water handling options used in various shale gas regions throughout the U.S.

Table 1: Current Produced Water Management By Shale Gas Basin			
Shale Gas Basin	**Water Management Technology**	**Availability**	**Comments**
Barnett Shale	Class II Injection Wells	Commercial and non-commercial	Disposal into the Barnett and underling Ellenberger Group
	Recycling	On-site treatment and recycling	For re-use in subsequent fracturing jobs
Fayetteville Shale	Class II Injection Wells	Non-commercial	Water is transported to two injection wells owned and operated by a single producing company
	Recycling	On-site recycling	For re-use in subsequent fracturing jobs
Haynsville Shale	Class II Injection Wells	Commercial and non-commercial	
Marcellus Shale	Class II Injection Wells	Commercial and non-commercial	Limited use of Class II injection wells
	Treatment and discharge	Municipal waste water treatment facilities, commercial facilities reportedly contemplated	Primarily in Pennsylvania
	Recycling	On-site recycling	For re-use in subsequent fracturing jobs
Woodford Shale	Class II Injection Wells	Commercial and non-commercial	Disposal into multiple confining formations
	Land Application		Permit required through the Oklahoma Corporation Commissio9n
	Recycling	Non-commercial	Water recycling and storage facilities at a central locations
Antrim Shale	Class II Injection Wells	Commercial and non-commercial	
New Albany Shale	Class II Injection Wells	Commercial and non-commercial	

From Modern Shale Gas Development in the United States: A Primer

3.6 Groundwater Protection

3.6.1 Hydraulic Fracturing Water Usage

Water and sand can make up more than 99.5 percent of the fluid used to hydraulically fracture a well. Water acts as the primary carrier fluid in hydraulic fracturing. Because the multi-stage fracturing of a single horizontal shale gas well can use several million gallons of water, it is critical that large quantities of relatively fresh water be reasonably available. The quality of the water is very important because impurities can reduce the efficiency of the additives used in the process.

Most water used in hydraulic fracturing comes from surface water sources such as lakes, rivers and municipal supplies. However, groundwater can be used to augment surface water supplies where it is available in sufficient quantities. In some states, the water used for fracturing is controlled by a river basin commission or water resources board such as the Susquahanna River Basin Commission‡ or the Delaware River Basin Commission‡. In other places, water is owned by private individuals who can allocate it at their discretion.

The amount of water used in hydraulic fracturing, particularly in shale gas formations, may appear substantial, but it is small when compared to other water uses such as agriculture, manufacturing and municipal water supply. For example, electric generation uses nearly 150 million gallons a day in the Susquehanna River Basin, while the projected total demand for peak Marcellus Shale activity in the same area is 8.4 million gallons per day.

The following chart shows estimated water usage in the United States for 2005 by category. Oil and gas operations are only part of the Mining category which in total comprised about 1% of the total water used in the United States in 2005.

The use of horizontal well high volume fracturing has accelerated significantly since 2005. The current total amount of water used for hydraulic fracturing as a percentage of water use by sectors is not yet available. As soon as the USGS publishes its report for 2010, this section of the website will be updated accordingly. However, according to a report developed for the Department of Energy by ALL Consulting, "Estimates of peak drilling activity in New York, Pennsylvania, and West Virginia indicate that maximum water use in the Marcellus, at the peak of production for each state, assuming 5 million gallons of water per well, would be about 650 million barrels per year. This represents less than 0.8 percent of the 85 billion barrels per year used in the area overlying the Marcellus Shale in New York, Pennsylvania, and West Virginia."

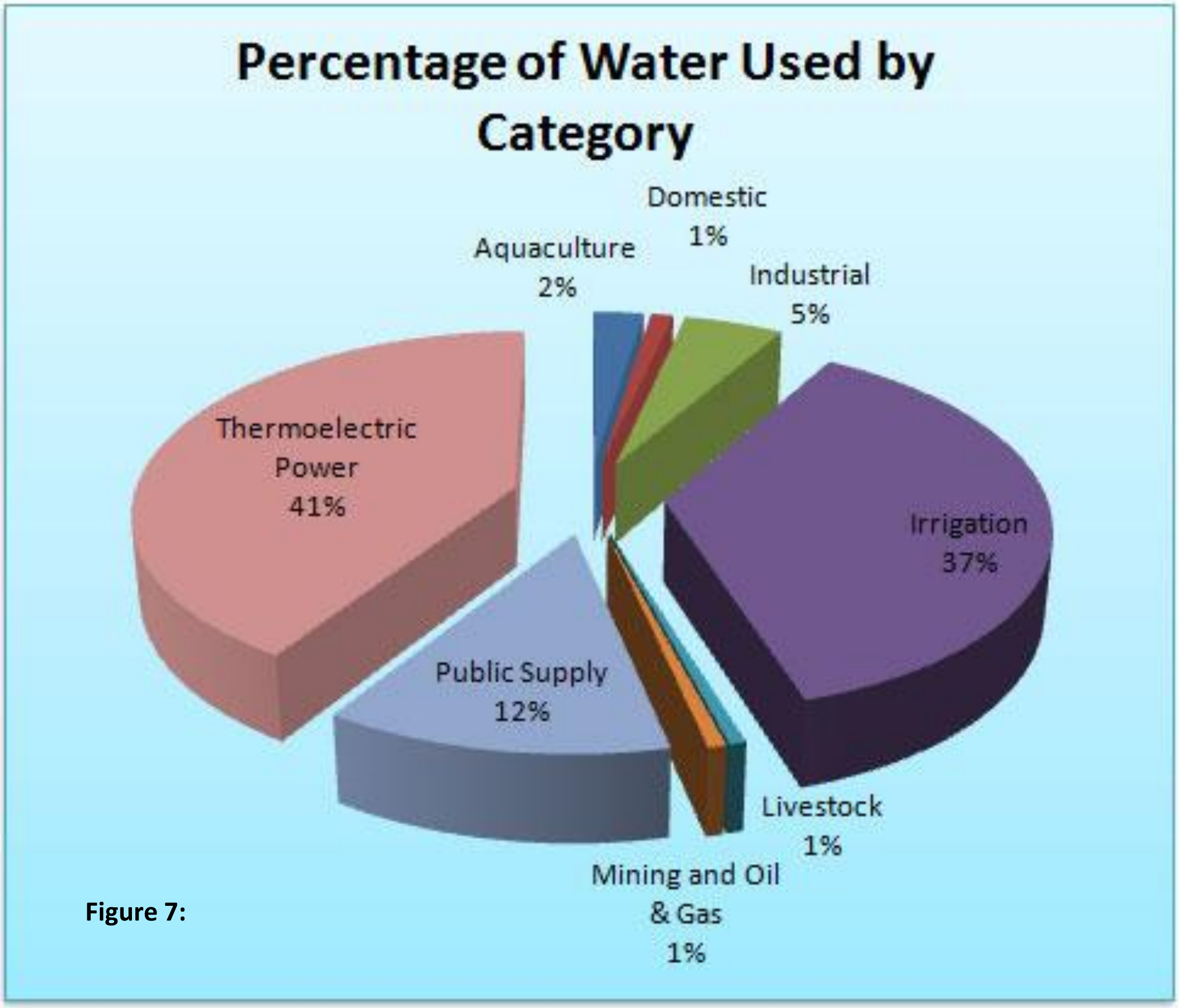


Figure 7:

Source: Estimated Use of Water in the United States 2005, USGS 2005

3.6.2 Water Use Management

One alternative that states and oil and gas operators are pursuing is to make use of seasonal changes in river flow to capture water when surface water flows are greatest. Utilizing seasonal flow differences allows planning of withdrawals to avoid potential impacts to municipal drinking water supplies or to aquatic or riparian communities. In the Fayetteville Shale play of Arkansas, one operator is constructing a 500-acre-ft impoundment to store water withdrawals from the Little Red River obtained during periods of high flow (storm events or hydroelectric power generation releases from Greer's Ferry Dam upstream of the intake) when excess water is available. The project is limited to 1,550 acre-ft of water annually (one acre-foot is equivalent to the volume of water required to cover one acre with one foot of water). The company has constructed extra pipelines and hydrants to provide portions of this rural area with water for fire protection. Also included is monitoring of stream water quality as well as game and nongame fish species in the reach of river surrounding the intake. Source: [Estimated Use of Water in the United States 2005, USGS 2005](http://fracfocus.org/).

In addition, new treatment technologies have made it possible to recycle the water recovered from hydraulic fracturing. The reuse of treated flowback fluids from hydraulic fracturing is being conducted by some operators in the Marcellus Shale region and at least one operator (Devon Energy) in the Barnett Shale in Texas.

3.6.3 Groundwater & Aquifers

Nearly half of the U.S. population relies on groundwater as their primary source of drinking water. In rural areas, this figure approaches 95%. It is easy to see from these figures that groundwater is an importance source of water that should be protected. But what exactly is groundwater?

Groundwater is the water that is held within the interconnected openings of saturated rock beneath the land surface in much the same way as water would be held in a bowl full of marbles. Although the marbles would fill the bowl, there would be spaces between the marbles. These spaces can hold fluid. As shown in the diagram above, this is how water exists in the subsurface.

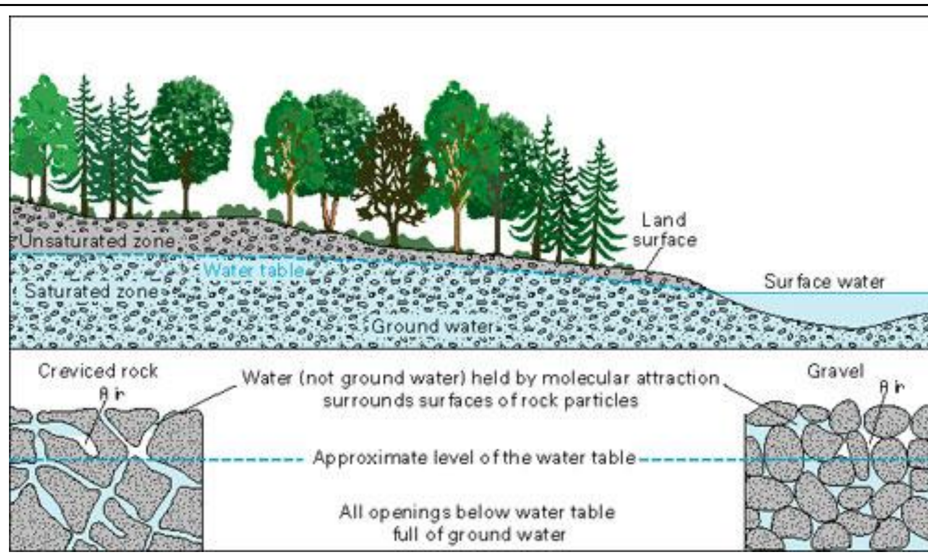


Figure 8: Groundwater

On the following figure, the hydrologic cycle‡shows that when rain falls to the ground, some water flows along the land surface to streams or lakes (e) and (g), some water evaporates into the atmosphere, some is taken up by plants, and some seeps into the ground.

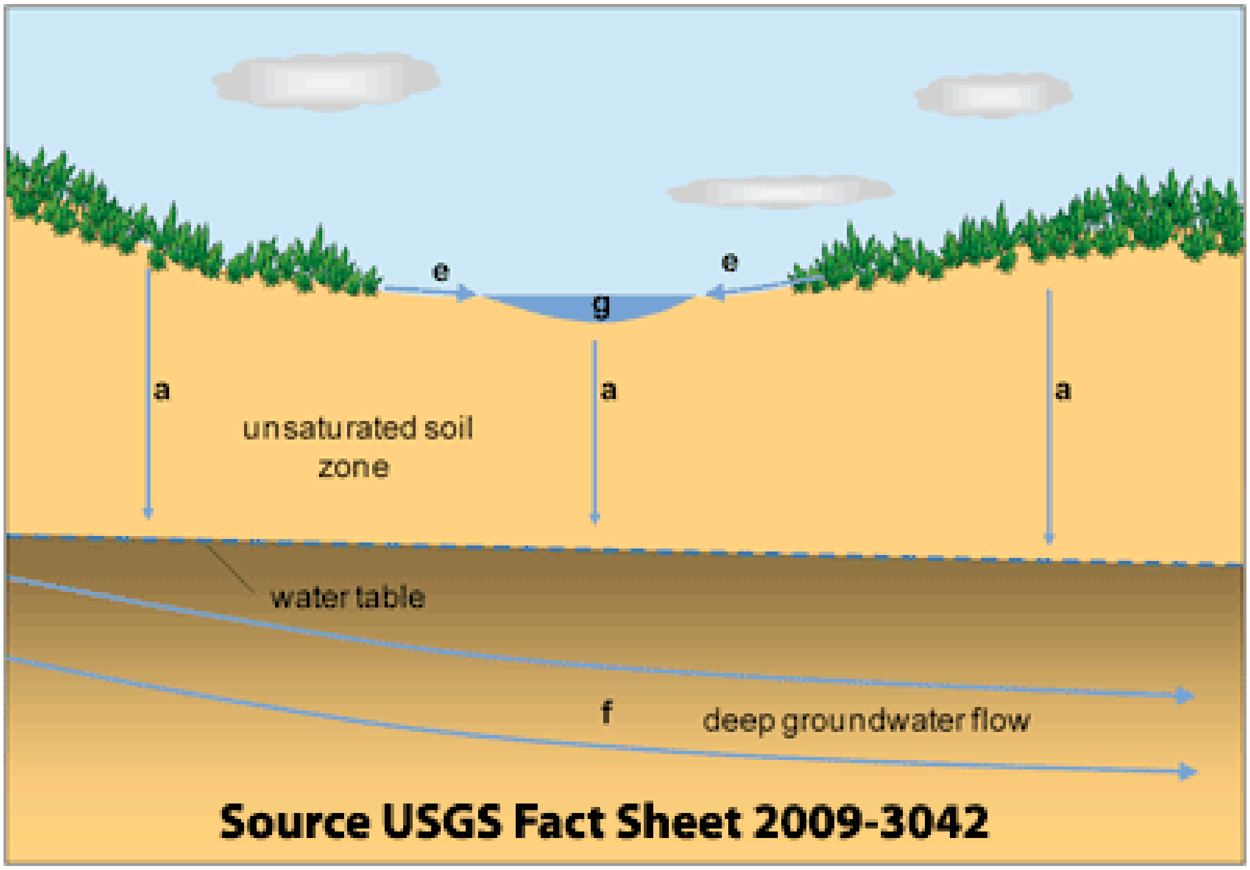


Figure 9: Hydrologic Cycle

As water begins to seep into the ground, it enters a zone (a) that contains both water and air, referred to as the unsaturated zone or vadose zone‡. The upper part of this zone, known as the root zone or soil zone, supports plant growth and is crisscrossed by living roots, holes left by decayed roots, and animal and worm burrows.

Below the root zone lies a capillary fringe‡ which results from the attraction between water and rocks. As a result of this attraction, water clings as a film on the surface of rock particl Water moves through the unsaturated zone into the saturated zone‡ (f), where all the interconnected openings between rock particles are filled with water. It is within this saturated zone that the term "groundwater" is correctly applied. Groundwater is held in aquifers which are discussed in the following sections.

3.6.4 Groundwater Myths:

- Groundwater moves rapidly.
- Groundwater migrates thousands of miles.
- There is no relationship between groundwater and surface water.
- Groundwater removed from the earth is never returned.
- Groundwater is mysterious and occult.
- Groundwater is not a significant source of water supply.

The figure below shows how groundwater is held in the spaces between rock particles.

Figure 10: Groundwater Storage

The Miriam Webster dictionary defines an aquifer as a "water-bearing stratum of permeable rock, sand, or gravel." Aquifers may contain fresh, brackish or salty water in volumes ranging from minor to large enough to serve a public water system. Aquifers that provide sustainable fresh groundwater to urban areas and for agriculture are usually located at depths of less than a few hundred feet below the ground surface.

Gravity is the dominant driving force in groundwater movement in aquifers that are not bounded above and below by impermeable rock. This is called an unconfined aquifer. Under natural conditions, groundwater moves "downhill" until it reaches the land surface at a spring such as the one shown below or through a seep in the side or bottom of a river bed, lake, wetland, or other surface water body.

Groundwater can also leave the aquifer via the pumping of a well. The process of groundwater outflowing into a surface water body or leaving the aquifer through pumping is called discharge.

Many rivers, lakes, and wetlands rely heavily on groundwater discharge as a source of water. During times of low precipitation, these bodies of water would not contain any water at all if it were not for groundwater discharge. It is important to note that because of discharge, contaminants in groundwater can flow into surface water bodies. This process can make the removal of contamination very complex.

Confined aquifers are bounded above and below by impermeable rock. The driving force of groundwater movement in confined aquifers is pressure, rather than gravity.

When the intersection between the aquifer and the land's surface is natural, the pathway is called a spring. A typical spring is shown at left. If discharge occurs through a well, that well is a flowing or artesian well. To read more about the movement of groundwater go to the National Ground Water Association website. There you will find an excellent discussion about groundwater hydrology‡. You can also get more information about aquifers on the U.S. Geological Survey website.‡

Figure 11: Natural Spring

3.6.5 Groundwater Quality & Testing

The quality of groundwater can affect not only our health, but also society and the economy. Groundwater contamination can adversely affect property values, the image of a community, economic development, and the overall quality of life we all share. Clean water at reasonable cost is essential and in many parts of the country, groundwater is the only economical water source available. Once groundwater has been contaminated, it is us -ually very difficult and costly to clean. Even small contamination sites often cost many thousands of dollars to cleanup. The quality of water from private water supplies, such as those from wells at individual homes, is not regulated. It is the responsibility of the well owner to ensure a safe drinking water supply. Although there are a few requirements for water quality testing and monitoring of private wells (i.e., in some areas, testing is required at the time of property transfer), it is recommended that all well owners have their water tested periodically. While "complete" drinking water analyses can be expensive and are generally unnecessary for the private well owner, it is recommended that private water supplies be tested routinely for common contaminants including total coliform bacteria, nitrates, and lead. These contaminants can occur in well water due to agricultural activity, septic system use, household chemical use/ disposal, age of the plumbing or industrial activity. The frequency of water testing and the contaminants to test for depend on factors such as the potential sources of pollution and the type of well. Another consideration is ensuring that the private well complies with proper well construction standards.

Figure 12:

A water's taste, smell, or color is not necessarily an indicator of water quality. Many of the most hazardous contaminants are undetectable to the senses. The only way to detect most pollutants is by testing.

Before hydraulic fracturing operations begin in a new area, American Petroleum Institute guidance (API - HF1) recommends that a baseline assessment program which includes the sampling of nearby water wells be conducted prior to hydraulic fracturing operations. Fresh water wells should also be sampled following hydraulic fracturing operations. At least one state (Colorado) requires the sampling of certain water wells in various areas of the state as part of their regulatory program. Another state (Pennsylvania) has regulations that presumptively place the burden of proof on any oil and gas company to demonstrate that they have not caused deterioration of the quality of groundwater used for drinking water purposes in the vicinity of oil and gas wells in the event of a contamination complaint.

In order to obtain valid results from sampling it is important to follow proper sampling and analysis protocols. Contact a state or EPA certified laboratory for sampling containers and instructions. Proper protocols may include:

- Using appropriate containers and seals;
- Purging of the well prior to sample capture;
- Collection at points before water treatment equipment;
- Following sample container filling procedures;
- Following storage and holding time requirements;
- Utilizing appropriate analysis methods; and,
- Following appropriate quality control/ quality assurance protocols.

Sampling should be conducted by someone familiar with sampling procedures. Analyses should be conducted by an accredited laboratory using appropriate analysis methods. You may be able to obtain a list of qualified laboratories by contacting your local Health Department, State Water Quality Agency shown on the Regulations By State page or County Extension Agent.

It is important for the landowner to have a oil and gas operational sampling and analysis of their groundwater conducted by a professional for constituents that may provide a reasonable baseline for post fracturing analysis. The National Ground Water Association maintains a list of groundwater professionals‡ you can review to help you find someone in your area to assist you. The following is a good basic list of constituents that should be considered for analysis prior to oil & gas operations.

- Major cations and anions
- Total Dissolved Solids
- Calcium
- Magnesium
- Sodium
- pH
- Arsenic
- Chromium
- Selenium
- Chloride
- Specific Conductance
- Barium
- Iron
- Boron
- Potassium

- Bicarbonate
- Dissolved Methane
- Benzene, Toluene, Ethyl benzene, Xylene (BTEX)
- Diesel Range Organics (DRO)
- Gasoline Range Organics (GRO)
- Total Petroleum Hydrocarbons or Oil & Grease (HEM)

Once hydraulic fracturing has taken place and a record of the actual chemicals used is available, it would be advisable to consider having a sampling and analysis conducted on the groundwater for the chemicals shown on the record that match those listed above. However, to minimize costs for the landowner, an alternative analysis should be conducted for at least TDS and Dissolved Methane. An increase in the concentration of either of these constituents could indicate that further, more complete sampling and analysis should be conducted.

You can learn more about the toxicity characteristics of chemicals by searching for the chemical using the name or CAS number on the USEPA National Center for Computational Toxicology‡ website. USEPA also maintains a Drinking Water Hotline that is available Monday-Friday from 8:30 AM-4:30 PM Eastern time at 1-800-426-4791.

Important: Only a trained professional such as a Toxicologist or a Physician can tell you if your water is safe to consume. You should not use the information obtained from this website, the USEPA Toxicology website or any other website to make decisions regarding the safety or drinkability of your water.

3.7 Well Construction & Groundwater Protection

3.7.1 What are casing and cementing?

Casing is typically hollow steel pipe used to line the inside of the drilled hole (wellbore) and is essential for protection of groundwater and aquifers in a drilling operation.

The existing industry standard for oil and gas casing was established by the American Petroleum Institute (API)‡ in Specification 5CT. It specifies the length, thickness, tensile strength and composition of casing for a given situation and is the most commonly used standard for the selection of oil and gas casing.

Each full length of casing is often referred to as a casing string. Wells are typically constructed of multiple casing strings including a surface string and production string. These strings are set in the well and cemented in place under specific state requirements. The API has also established standards for cement types. These standards are covered by Specification 10A, which lists a variety of oil and gas cements.

Cementing is the process of placing a cement sheath around casing strings. Although Class A (Portland) cement‡ is the most common cement used in the oil and gas industry, the actual type of cement can be tailored to the individual well, depending on what the state's rules allow. For example, some wells penetrate formations that are difficult to cement because of their porous nature or due to a substantial water flow within the formation. In such cases, additives like cellophane flake and calcium chloride are sometimes added to the cement to seal off such zones, quicken the cement hardening process, and prevent washout of the cement.

3.7.2 The casing and cemening process

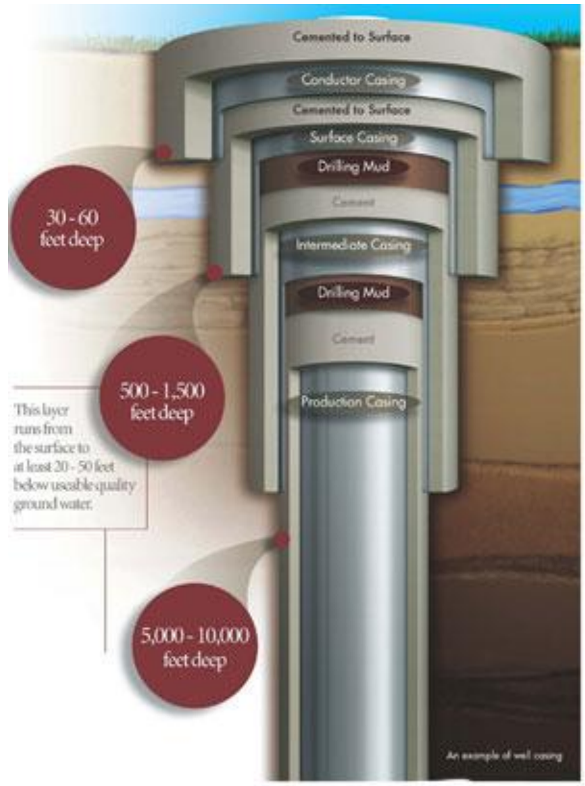
In general, the casing of oil and gas wells, whether vertical or horizontal, is accomplished in multiple phases from the largest diameter casing to the smallest.

- The first phase often involves the setting of conductor casing. The purpose of this casing is to prevent the sides of the hole from caving into the wellbore. It is not always necessary.
- After the conductor casing string is set in place, drilling continues inside the conductor casing string to below the lowest ground water zone depending upon regulatory requirements. Surface casing is then run from the surface to just above the bottom of the hole. Cement is pumped down the inside of the casing, forcing it up from the bottom of the surface casing into the space between the outside of the surface casing and the wellbore. This space is called the annulus.
- Once a sufficient volume of cement to fill the annulus is pumped into the casing, it is usually followed by pumping a volume of fresh water into the casing until the cement begins to return to the surface in the annular space. The cementing of casing from bottom to top using this method is called circulation. The circulation of cement behind surface casing insures that the entire annular space fills with cement from below the deepest ground water zone to the surface.
- While nearly all states require the circulation of cement on surface casing, it is not a universal requirement. In some states, cement is required only across the deepest ground water zone. Regardless, such variations from the circulation of cement on surface casing are still designed to ensure that ground water zones are isolated and protected from oil and gas production zones.

- Once the surface casing is set and the cement has had time to cure, the wellbore is drilled down to the next zone where casing will be set. In some states this results in the placement of intermediate casing.
- Intermediate casing is usually only required for specific reasons, such as when additional control of fluid flow and pressure is needed, or to protect other underground resources such as minable coals or gas storage zones.
- After the surface (and if needed, intermediate casing) strings are set, the well is drilled to the target formation. Upon reaching this zone, production casing is typically set at either the top of, or into, the producing formation. The placement of production casing depends on whether the well will be produced directly from the formation ("open-hole") or through perforations in the production casing.
- The production casing is typically set into place with cement using the same method as the one used for surface and intermediate casing. In drill holes that deviate from vertical, casing centralizers like the one shown above are placed on the outside of the casing to center it in the hole. This ensures that cement will completely surround the casing.
- Tubing is also used under certain circumstances in some states. Typically, tubing is set into an internal seal called a packer at the bottom of the well rather than cemented in like casing.

3.7.3 Why casing and cementing are an important part of groundwater protection.

Casing strings are an important element of well completion with respect to the protection of groundwater resources because they provide for the isolation of fresh water zones and groundwater from the inside of the well. Casing is also used to transmit flowback fluids from well treatment. In this regard, surface casing is the first line of defense and production casing provides a second layer of protection for groundwater. As important as casing is, it is the cementation of the casing that adds the most value to the process of groundwater protection. Proper sealing of annular spaces with cement creates a hydraulic barrier to both vertical and horizontal fluid migration. Consequently, the quality of the initial cement job is a critical factor in the prevention of fluid movement from deeper zones into groundwater resources. In some states it is common for state personnel to witness the running and cementing of casing strings, while in other states the submission of a completion report which details the amounts and types of casing and cement used in the completion of the well is considered sufficient evidence of proper well construction. In a few states such as Alaska, Michigan and Ohio, an additional verification method using geophysical logs such as Cement Bond Logs (CBL) and Variable Density Logs (VDL) may be required. By measuring the travel time of sound waves through the casing and cement to the formation, the CBL shows the quality of bonding between the casing and the cement. The VDL performs a similar function to measure the bond between the cement and the borehole. By measuring the quality of the cement to casing and cement to formation bond, the sealing quality of the cement in the space between the casing and the borehole (called the annulus)can be evaluated.



Graphic Courtesy of Texas Oil and Gas Association

Figure 13: Well Casings

3.7.4 State Regulation of Well Construction

In a review of the regulations of twenty-seven state oil and gas agency regulations conducted in 2009 by the GWPC, the following percentage of states had the listed requirement for casing and cementing:

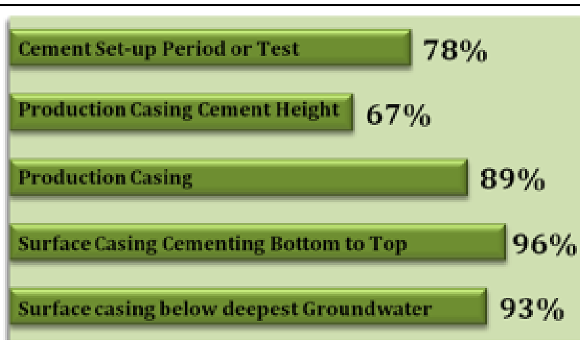


Figure 14: State for Requirement for Casing and Cementing

Although some states require complete circulation of cement from the bottom to the top of the production casing, most states require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation. For example, in Arkansas, production casing must be cemented to two-hundred-fifty feet above all producing intervals.

There are a number of reasons why cement circulation from bottom to top on production casing is not always required including the fact that in very deep wells, the circulation of cement may be unnecessary due to the differences in depth between the production zone and fresh groundwater zones. Also, under certain circumstances, cementing must be handled in multiple stages which can result in a poor cement job or damage to the casing if not done properly. Finally, the circulation of cement on production casing prevents the monitoring of the space between the casing strings for changes in pressure which could indicate leakage through the casing or cement sheath.

For more information about the regulatory requirements of each oil and gas producing state, go to the Regulations By State page or the report *State Oil and Natural Gas Regulations Designed to Protect Water Resources*.

3.7.5 Fluid Flow in the Subsurface (Darcy's Law)

The principle that governs how fluid moves in the subsurface is called Darcy's law. Darcy's law is an equation that defines the ability of a fluid to flow through a porous media such as rock. It relies on the fact that the amount of flow between two points is directly related to the difference in pressure between the points, the distance between the points, and the interconnectivity of flow pathways in the rock between the points. The measurement of interconnectivity is called permeability.

Figure 15: Shale Sample

In the subsurface, rock is deposited in layers. Fluid flow within and between the rock layers is governed by the permeability of the rocks. However, to account for permeability, it must be measured in both the vertical and horizontal directions. For example, shale typically has permeabilities that are much lower vertically than horizontally (assuming flat lying shale beds). This means that it is difficult for fluid to flow up and down through a shale bed but much easier for it to flow from side to side. A good example of this characteristic is shown in the picture at left; which clearly indicates that it would be much easier for water to flow along the horizontal bedding planes in the shale where there are natural flow pathways instead of vertically where there are few flow pathways.

Ultimately, if the pressure difference between a hydraulically fractured zone and a fresh water aquifer is not great, the distance between the zones is relatively large, and there are rocks with low vertical permeabilities in between the deeper and the shallower zones, flow between the zones is unlikely to occur. The exception to this is where there is a separate flow pathway such as an open borehole or a series of faults or joints that intersect both the fractured zone and the fresh water aquifer. Under either of these circumstances, the pressure difference and distance will be the determining factors as to whether fluid can migrate from the lower to the upper zone.

For those with a greater interest in the mathematic principles behind fluid flow in the subsurface, the following is a description of Darcy's Law:

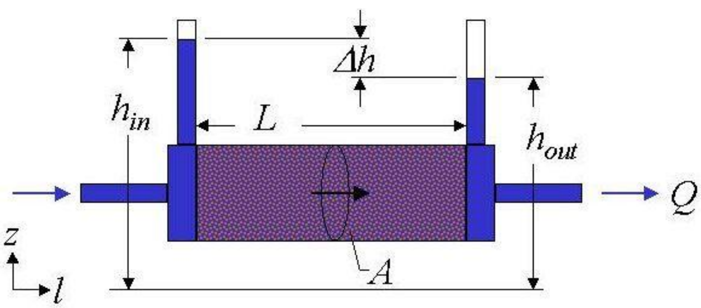
Darcy’s law is the equation that defines the ability of a fluid to flow through a porous media such as rock. It relies on the principle that the amount of flow between two points is directly proportional to the difference in pressure between the points and the ability of the media through which it is flowing to impede the flow. Here pressure refers to the excess of local pressure over the normal hydrostatic fluid pressure which, due to gravity, increases with depth like in a standing column of water. This factor of flow impedance is referred to as permeability. Put another way, Darcy's law is a simple proportional relationship between the instantaneous discharge rate through a porous medium and the pressure drop over a given distance.

In modern format, using a particular sign convention, Darcy's law is usually written as: **Q = -KA dh/dl**

where:

- Q = rate of water flow (volume per time)
- K = hydraulic conductivity
- A = column cross sectional area
- dh/dl = hydraulic gradient, that is, the change in head over the length of interest.

Figure 16 below is a diagrammatic expression of Darcy's Law:



When calculating the possibility of fluid flow from a hydraulically fractured zone to a fresh water zone the application of Darcy's law is critical because it sets out the specific conditions under which fluid could flow from one zone to another and will ultimately determine whether or not hydraulic fracturing fluids can reach a fresh water zone.

The darcy is referenced to a mixture of unit systems. A medium with a permeability of 1 darcy permits a flow of 1 cm^3/s of a fluid with viscosity 1 cP (1 mPa·s) under a pressure gradient of 1 atm/cm acting across an area of 1 cm^2. A millidarcy (mD) is equal to 0.001 darcy.

4.0 CHEMICAL USE IN HYDRAULIC FRACTURING

4.1 Introduction to Chemical Use

Chemicals serve many functions in hydraulic fracturing. From limiting the growth of bacteria to preventing corrosion of the well casing, chemicals are needed to insure that the fracturing job is effective and efficient.

The number of chemical additives used in a typical fracture treatment depends on the conditions of the specific well being fractured. A typical fracture treatment will use very low concentrations of between 3 and 12 additive chemicals, depending on the characteristics of the water and the shale formation being fractured. Each component serves a specific, engineered purpose. For example, the predominant fluids currently being used for fracture treatments in the gas shale plays are water-based fracturing fluids mixed with friction-reducing additives (called slickwater). The addition of friction reducers allows fracturing fluids and sand, or other solid materials called proppants, to be pumped to the target zone at a higher rate and reduced pressure than if water alone were used. In addition to friction reducers, other additives include: biocides to prevent microorganism growth and to reduce biofouling of the fractures; oxygen scavengers and other stabilizers to prevent corrosion of metal pipes; and acids that are used to remove drilling mud damage within the near-wellbore area.

Fluids are used to create the fractures in the formation and to carry a propping agent (typically silica sand) which is deposited in the induced fractures to keep them from closing up. The chart below taken from Modern Shale Gas Development in the United States: A Primer demonstrates the volumetric percentages of additives that were used for a nine-stage hydraulic fracturing treatment of a Fayetteville Shale horizontal well.

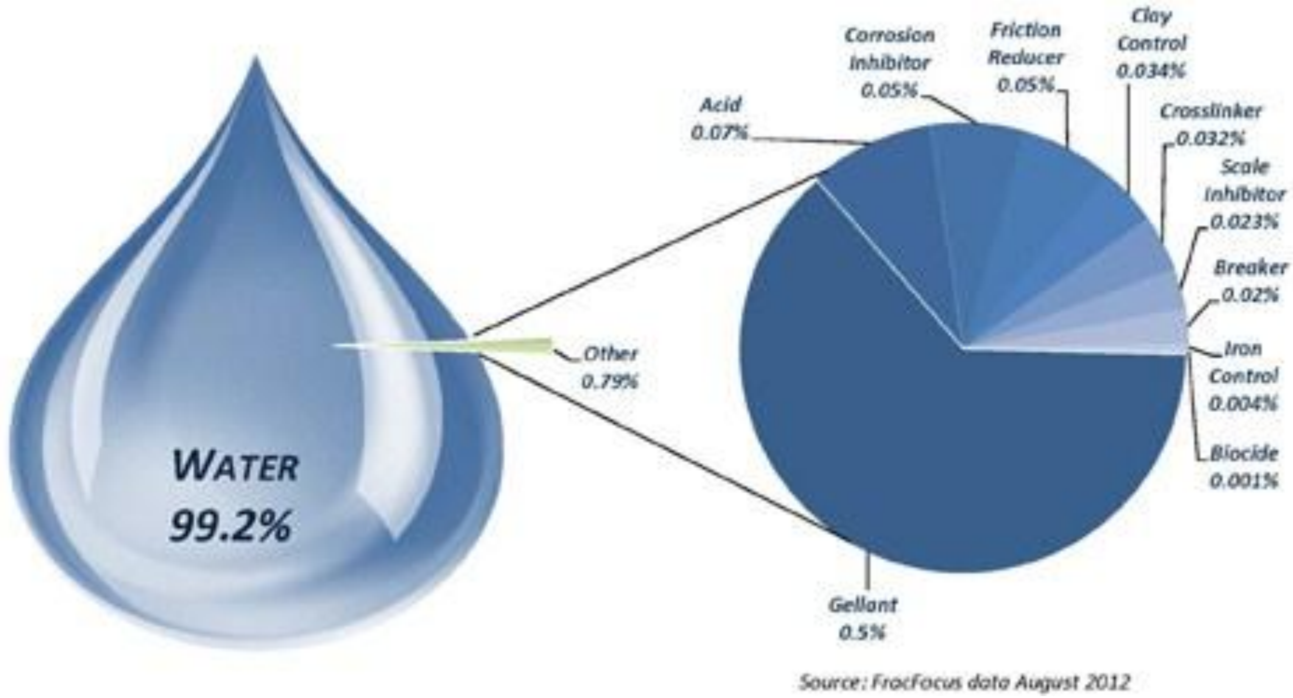


Figure 17: Average Hydraulic Fracturing Fluid Composition for U.S. Shale Plays

The make-up of fracturing fluid varies from one geologic basin or formation to another. Evaluating the relative volumes of the components of a fracturing fluid reveals the relatively small volume of additives that are present. The additives depicted on the right side of the pie chart represent less than 0.5% of the total fluid volume. Overall the concentration of additives in most slickwater fracturing fluids is a relatively consistent 0.5% to 2% with water making up 98% to 99.5%.

Because the make-up of each fracturing fluid varies to meet the specific needs of each area, there is no one-size-fits-all formula for the volumes for each additive. In classifying fracturing fluids and their additives it is important to realize that service companies that provide these additives have developed a number of compounds with similar functional properties to be used for the same purpose in different well environments. The difference between additive formulations may be as small as a change in concentration of a specific compound.

Although the hydraulic fracturing industry may have a number of compounds that can be used in a hydraulic fracturing fluid, any single fracturing job would only use a few of the available additives. For example, the chart shown above, represents 12 additives used, covering the range of possible functions that could be built into a fracturing fluid.

4.2 Why Chemicals Are Used

Given today's technology, chemicals must be used in hydraulic fracturing to ensure the producing formation is effectively treated. The chart shown below depicts generic hydraulic fracturing chemical usage including the types of chemicals, their uses in the process and the consequences of not using them.

Chemicals Commonly Used in Shale Fracturing and consequences of not using the chemical

Chemical	Use	Consequences of not using chemical
Acid	Removes near well damage	Higher treating pressure, slightly more engine emissions.
Biocides	Controls bacterial growth	Increased risk of souring the formation (H_2S gas from sulfate reducing bacteria growth) and increasing corrosion.
Corrosion Inhibitor	Used in the acid to prevent corrosion of pipe	Sharply increased risk of pipe corrosion from acid. Well integrity compromised.
Friction Reducers	Decreases pumping friction	Significantly increases surface pressure and frac pump engine emissions .
Gelling Agents	Improves proppant placement	Increased water use. Natural gas recovery may decrease in some cases by 30 to 50% where frac fluids must be gelled (conventional fracs).
Oxygen scavenger	Prevents corrosion of well tubulars by oxygen	Corrosion sharply increased and well integrity (containment) compromised.

Table 2:

4.2 What Chemicals Are Used

As previously noted, chemicals perform many functions in a hydraulic fracturing job. Although there are dozens to hundreds of chemicals which could be used as additives, there are a limited number which are routinely used in hydraulic fracturing. The following is a list of the chemicals used most often. This chart is sorted alphabetically by the Product Function to make it easier for you to compare to the fracturing records.

Table 3: Chemicals Utilized in Hydraulic Fracturing			
Chemical Name	**CAS**	**Chemical Purpose**	**Product Function**
Hydrochloric Acid	007647-01-0	Helps dissolve minerals and initiate cracks in the rock	Acid
Glutaraldehyde	000111-30-8	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Quaternary Ammonium Chloride	012125-02-9	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Quaternary Ammonium Chloride	061789-71-1	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Tetrakis Hydroxymethyl-Phosphonium Sulfate	055566-30-8	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Ammonium Persulfate	007727-54-0	Allows a delayed break down of the gel	Breaker
Sodium Chloride	007647-14-5	Product Stabilizer	Breaker
Magnesium Peroxide	014452-57-4	Allows a delayed break down the gel	Breaker
Magnesium Oxide	001309-48-4	Allows a delayed break down the gel	Breaker
Calcium Chloride	010043-52-4	Product Stabilizer	Breaker
Choline Chloride	000067-48-1	Prevents clays from swelling or shifting	Clay Stabilizer
Tetramethyl ammonium chloride	000075-57-0	Prevents clays from swelling or shifting	Clay Stabilizer
Sodium Chloride	007647-14-5	Prevents clays from swelling or shifting	Clay Stabilizer
Isopropanol	000067-63-0	Product stabilizer and / or winterizing agent	Corrosion Inhibitor
Methanol	000067-56-1	Product stabilizer and / or winterizing agent	Corrosion Inhibitor
Formic Acid	000064-18-6	Prevents the corrosion of the pipe	Corrosion Inhibitor
Acetaldehyde	000075-07-0	Prevents the corrosion of the pipe	Corrosion Inhibitor
Petroleum Distillate	064741-85-1	Carrier fluid for borate or zirconate crosslinker	Crosslinker
Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for borate or zirconate crosslinker	Crosslinker
Potassium Metaborate	013709-94-9	Maintains fluid viscosity as temperature increases	Crosslinker
Triethanolamine Zirconate	101033-44-7	Maintains fluid viscosity as temperature increases	Crosslinker
Sodium Tetraborate	001303-96-4	Maintains fluid viscosity as temperature increases	Crosslinker
Boric Acid	001333-73-9	Maintains fluid viscosity as temperature increases	Crosslinker

Table 3: Chemicals Utilized in Hydraulic Fracturing			
Chemical Name	**CAS**	**Chemical Purpose**	**Product Function**
Zirconium Complex	113184-20-6	Maintains fluid viscosity as temperature increases	Crosslinker
Borate Salts	N/A	Maintains fluid viscosity as temperature increases	Crosslinker
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Crosslinker
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Crosslinker
Polyacrylamide	009003-05-8	“Slicks” the water to minimize friction	Friction Reducer
Petroleum Distillate	064741-85-1	Carrier fluid for polyacrylamide friction reducer	Friction Reducer
Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for polyacrylamide friction reducer	Friction Reducer
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Friction Reducer
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Friction Reducer
Guar Gum	009000-30-0	Thickens the water in order to suspend the sand	Gelling Agent
Petroleum Distillate	064741-85-1	Carrier fluid for guar gum in liquid gels	Gelling Agent
Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for guar gum in liquid gels	Gelling Agent
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Gelling Agent
Polysaccharide Blend	068130-15-4	Thickens the water in order to suspend the sand	Gelling Agent
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Gelling Agent
Citric Acid	000077-92-9	Prevents precipitation of metal oxides	Iron Control
Acetic Acid	000064-19-7	Prevents precipitation of metal oxides	Iron Control
Thioglycolic Acid	000068-11-1	Prevents precipitation of metal oxides	Iron Control
Sodium Erythorbate	006381-77-7	Prevents precipitation of metal oxides	Iron Control
Lauryl Sulfate	000151-21-3	Used to prevent the formation of emulsions in the fracture fluid	Non-Emulsifier
Isopropanol	000067-63-0	Product stabilizer and / or winterizing agent.	Non-Emulsifier
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Non-Emulsifier
Sodium Hydroxide	001310-73-2	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent

Table 3: Chemicals Utilized in Hydraulic Fracturing			
Chemical Name	**CAS**	**Chemical Purpose**	**Product Function**
Potassium Hydroxide	001310-58-3	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Acetic Acid	000064-19-7	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Sodium Carbonate	000497-19-8	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Potassium Carbonate	000584-08-7	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Copolymer of Acrylamide and Sodium Acrylate	025987-30-8	Prevents scale deposits in the pipe	Scale Inhibitor
Sodium Polycarboxylate	N/A	Prevents scale deposits in the pipe	Scale Inhibitor
Phosphonic Acid Salt	N/A	Prevents scale deposits in the pipe	Scale Inhibitor
Lauryl Sulfate	000151-21-3	Used to increase the viscosity of the fracture fluid	Surfactant
Ethanol	000064-17-5	Product stabilizer and / or winterizing agent.	Surfactant
Naphthalene	000091-20-3	Carrier fluid for the active surfactant ingredients	Surfactant
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Surfactant
Isopropyl Alcohol	000067-63-0	Product stabilizer and / or winterizing agent.	Surfactant
2-Butoxyethanol	000111-76-2	Product stabilizer	Surfactant

One of the problems associated with identifying chemicals is that some chemicals have multiple names. For example Ethylene Glycol (Antifreeze) is also known by the names Ethylene alcohol; Glycol; Glycol alcohol; Lutrol 9; Macrogol 400 BPC; Monoethylene glycol; Ramp; Tescol; 1,2-Dihydroxyethane; 2-Hydroxyethanol; HOCH2CH2OH; Dihydroxyethane; Ethanediol; Ethylene gycol; Glygen; Athylenglykol; Ethane-1,2-diol; Fridex; M.e.g.; 1,2-Ethandiol; Ucar 17; Dowtherm SR 1; Norkool; Zerex; Aliphatic diol; Ilexan E; Ethane-1,2-diol 1,2-Ethanedio.

This multiplicity of names can make a search for chemicals somewhat difficult and frustrating. However, if you search for a chemical by the CAS number it will return the correct chemical even if the name on the fracturing record does not match. For example if the fracturing record listed the chemical Hydrogen chloride and you searched for it by name using a chemical search site you may not get a result. But if you search for CAS# 007647-01-0 it might return Hydrochloric acid which is another name of Hydrogen chloride. Therefore, by using the CAS number you can avoid the issue of multiple names for the same chemical.

Multiple names for the same chemical can also leave you with the impression that there are more chemicals than actually exist. If you search the National Institute of Standards and Technology (NIST)‡ website the alternate names of chemicals are listed. This may help you identify the precise chemical you are looking for. The NIST site also contains the CAS numbers for chemicals. NIST is only one of many websites you can use to locate additional information about chemicals. You can also search the following websites using the chemical name or CAS number:

- OSHA/EPA Occupational Chemical Database‡
- The Chemical Database‡
- EPA Chemical Fact Sheets‡

4.3 Chemicals & Public Disclosure

In 1986, Congress enacted the Emergency Planning and Community Right to Know Act (EPCRA)‡. EPCRA established requirements for federal, state and local governments, tribes, and industry regarding emergency planning and "community right-to-know" reporting on hazardous and toxic chemicals. The community right-to-know provisions of EPCRA are the most relevant part of the law for shale gas producers. These provisions help i ncrease the public's knowledge and access to information on chemicals at individual facilities, along with their uses and potential releases into the environment. Under Sections 311 and 312 of EPCRA, facilities manufacturing, processing, or storing designated hazardous chemicals must make Material Safety Data Sheets (MSDS), describing the properties and health effects of these chemicals, available to state and local officials and local fire departments. Facilities must also provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDS exist. Information about chemical inventories at facilities and MSDS must be available to the public. Facilities that store over 10,000 pounds of hazardous chemicals are subject to this requirement. Any hazardous chemicals above the threshold stored at shale gas production and processing sites must be reported in this manner.

> *Facilities meeting the threshold requirements must provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDS exist.*

Section 313 of EPCRA authorizes EPA's Toxics Release Inventory (TRI)‡, which is a publicly available database that contains information on toxic chemical releases and waste management activities reported annually by certain industries as well as federal facilities. EPA issues a list of industries that must report releases for the database. To date, EPA has not included oil and gas extraction as an industry that must report under TRI. This is not an exemption in the law. Rather it is a decision by EPA that this industry is not a high priority for reporting under TRI. Part of the rationale for this decision is based on the fact that most of the information required under TRI is already reported by producers to state agencies that make it publicly available. Also, TRI reporting from the hundreds of thousands of oil and gas sites would overwhelm the existing EPA reporting system and make it difficult to extract meaningful data from the massive amount of information submitted.

While shale gas production facilities do not normally store the materials subject to EPCRA reporting, a limited number of chemicals used in the hydraulic fracturing process - such as hydrochloric acid - are classified as hazardous under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) which requires reporting of releases into the environment of these materials. Further, EPCRA section 304 requires reporting of releases to the environment of certain materials. This includes releases of products used in oil and gas production that exceed reporting thresholds, even if those products are exempt from CERCLA reporting. These chemicals may be brought on site for a few days, at most, during fracturing or work-over operations. Businesses must report non-permitted releases—into the atmosphere, surface water, or groundwater—of any listed chemical above threshold amounts, known as the "reportable quantity", to federal, state, and local authorities. Therefore, while every precaution is taken to prevent chemical spills, in the event of an accidental release above the reportable quantity, a report would be made to these authorities by the operator.

In addition to federal disclosure laws, many states have developed or are developing public disclosure rules related to hydraulic fracturing. These states include Wyoming, Pennsylvania, Arkansas, Texas, Colorado, New Mexico, Montana, West Virginia, Idaho, and North Dakota. Although the content of these rules differs, the intent of each is to provide the public with information about the chemicals being used to fracture wells. The changes in state public disclosure laws are occuring so fast that posting a comprehensive list of all states contemplating or preparing laws in this area is not possible as it would change on a frequent basis. Table 4 provides state agency contact information related to oil and gas wells.

Table 4: State Agency Contact Information

Alabama Contact Information
Oil and Natural Gas Representatives:
State Oil & Gas Board of Alabama
Phone: 205.247.3579
Email: dbolin@ogb.state.al.us

Alaska Contact Information
Oil and Natural Gas Representatives:
Alaska Oil & Gas Conservation Commission
Phone: 907.279.1433
Email: aogcc.customer.svc@alaska.gov

Arizona Contact Information
Oil and Natural Gas Representatives:
Arizona Geological Survey
Phone: 520.770.3500
Email: Steve.rauzi@azgs.az.gov

Arkansas Contact Information
Oil and Natural Gas Representatives:
Arkansas Oil & Gas Commission
Phone: 501.683.5814
Email: larry.bengal@aogc.state.ar.us

California Contact Information
Oil and Natural Gas Representatives:
Department of Conservation, Division of Oil, Gas and Geothermal Resources
Phone: 916.445.9686
Email: DOGGR_Headquarters@conservation.ca.gov

Colorado Contact Information
Oil and Natural Gas Representatives:
Colorado Oil & Gas Conservation Commission
Phone: 303.894.2100
Email: dnr.ogcc@state.co.us

Connecticut Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

Delaware Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

Florida Contact Information
Oil and Natural Gas Representatives:
Department of Environmental Protection
Phone: 850-488-8217

Georgia Contact Information
Oil and Natural Gas Representatives:
Department of Natural Resources
Phone: 404.656.3500

Hawaii Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

Idaho Contact Information
Oil and Natural Gas Representatives:
Idaho Department of Lands
Phone: 208.334.0261
Email: EWilson@idl.idaho.gov

Illinois Contact Information
Oil and Natural Gas Representatives:
Department of Natural Resources
Phone: 217.782.1286
Email: duane.pulliam@illinois.gov

Indiana Contact Information
Oil and Natural Gas Representatives:
Division of Oil and Gas
Phone: 317.232.4055
Email: hmcdivitt@dnr.in.gov

Iowa Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

Kansas Contact Information
Oil and Natural Gas Representatives:
Oil and Gas Conservation Division
Phone: 316.337.6200
Email: d.louis@kcc.ks.gov

Kentucky Contact Information
Oil and Natural Gas Representatives:

Division of Oil and Gas
Phone: 502.573.0147
Email: Marvin.Combs@ky.gov

Louisiana Contact Information

Oil and Natural Gas Representatives:
Office of Conservation
Phone: 225.342.5500
Email: jim.welsh@la.gov

Maine Contact Information

Oil and Natural Gas Representatives:
No oil and gas agency

Maryland Contact Information

Oil and Natural Gas Representatives:
Maryland Department of the Environment
Phone: 410.537.3557
Email: elarrimore@mde.state.md.us

Massachusetts Contact Information

Oil and Natural Gas Representatives:
No oil and gas agency

Michigan Contact Information

Oil and Natural Gas Representatives:
Office of Geological Survey
Phone: 517.335.6387
Email: jankowskip@michigan.gov

Minnesota Contact Information

Oil and Natural Gas Representatives:
No oil and gas agency

Mississippi Contact Information

Oil and Natural Gas Representatives:
Mississippi Oil and Gas Board
Phone: 601.576.4920
Email: livshin@ogb.state.ms.us

Missouri Contact Information

Oil and Natural Gas Representatives:
Division of Geology and Land Survey
Phone: 573.368.2125
Email: gspgeol@dnr.mo.gov

Montana Contact Information

Oil and Natural Gas Representatives:
Montana Board of Oil and Gas
Phone: 406.656.0040
Email: trichmond@mt.gov

Nebraska Contact Information

Oil and Natural Gas Representatives:
Nebraska Oil & Gas Concervation Commission
Phone: 308.254.6919

Nevada Contact Information

Oil and Natural Gas Representatives:
Division of Minerals
Phone: 775.684.7047
Email: acoyner@govmail.state.nv.us

New Hampshire Contact Information

Oil and Natural Gas Representatives:
No oil and gas agency

New Jersey Contact Information

Oil and Natural Gas Representatives:
No oil and gas agency

New Mexico Contact Information

Oil and Natural Gas Representatives:
New Mexico Oil Conservation Commission
Phone: 505.476.3490
Email: CarlJ.Chavez@state.nm.us

New York Contact Information

Oil and Natural Gas Representatives:
Division of Mineral Resources
Phone: 518.402.8056
Email: dmnog@gw.dec.state.ny.us

North Carolina Contact Information

Oil and Natural Gas Representatives:
Division of Land Resources
Phone: 919.733.3833
Email: jim.simons@ncmail.net

North Dakota Contact Information

Oil and Natural Gas Representatives:
Department of Mineral Resources
Phone: 701.328.8020
Email: oilandgasinfo@nd.gov

Ohio Contact Information

Oil and Natural Gas Representatives:

Division of Mineral Resource Management
Phone: 614.265.7058
Email: tom.tugend@dnr.state.oh.us

Oklahoma Contact Information
Oil and Natural Gas Representatives:
Oklahoma Corporation Commission
Phone: 405.521.2301

Oregon Contact Information
Oil and Natural Gas Representatives:
Department of Geology and Mineral Industries
Phone: 971.673.1550
Email: vicki.mcconnell@dogami.state.or.us

Pennsylvania Contact Information
Oil and Natural Gas Representatives:
Bureau of Oil & Gas Management
Phone: 717.772.2199
Email: www.depweb.state.pa.us

Rhode Island Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

South Carolina Contact Information
Oil and Natural Gas Representatives:
Bureau of Land and Waste Management
Phone: 803.896.4011
Email: taylorgk@dhec.sc.gov

South Dakota Contact Information
Oil and Natural Gas Representatives:
Oil and Gas Section
Phone: 605.394.2229
Email: fred.steece@state.sd.us

Tennessee Contact Information
Oil and Natural Gas Representatives:
State Oil & Gas Board
Phone: 615.532.0166
Email: michael.k.burton@state.tn.us

Texas Contact Information
Oil and Natural Gas Representatives:
Railroad Commission of Texas
Phone: 512.463.7308
Email: leslie.savage@rrc.state.tx.us

Utah Contact Information
Oil and Natural Gas Representatives:
Division of Oil, Gas and Mining
Phone: 801.538.5334
Email: johnbaza@utah.gov

Vermont Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

Virginia Contact Information
Oil and Natural Gas Representatives:
Department of Mines, Minerals and Energy;
Division of Gas and Oil
Phone: 276.415.9700

Washington Contact Information
Oil and Natural Gas Representatives:
Division of Geology and Earth Resources,
Washington Geological Survey
Phone: 360.902.1439
Email: dave.norman@dnr.wa.gov

West Virginia Contact Information
Oil and Natural Gas Representatives:
Office of Oil and Gas
Phone: 304.926.0450
Email: james.a.martin@wv.gov

Wisconsin Contact Information
Oil and Natural Gas Representatives:
No oil and gas agency

Wyoming Contact Information
Oil and Natural Gas Representatives:
Oil and Gas Conservation Commission
Phone: 307.234.7147
Email: tdoll@wyo.gov

5.0 FREQUENTLY ASKED QUESTIONS

What happens to chemicals after they are pumped downhole?

Chemicals used in hydraulic fracturng are often transformed or degraded by their interaction with formations and formation fluids. For many chemicals of concern a recent presentation made by Dr. Angus McGrath of the environmental consulting company Stantec entitled "Fate and Transport of Select Compounds of Interest in Fracing Fluids" describes the fate of chemicals. It is available on the USEPA website at http://www.epa.gov/hfstudy/fateandtransportofselectcompoundsofinterestinfracingfluids.pdf ‡

Which companies participate in FracFocus?

The list of companies that participate in FracFocus is continually growing. To see a list of the current participating companies click HERE.

What information is contained in the hydraulic fracturing records?

The following is a list of elements contained in the hydraulic fracturing records viewable on this site and an explanation of what each element means. The header of each fracturing record contains the following information:

1. *Fracture date: This is the date on which the fracturing associated with the record occurred.*
2. *State: The name of the state in which the surface location of the well is located.*
3. *County: The name of the county within the state.*
4. *API Number: This number is assigned under a system developed by the American Petroleum Institute. API numbers are formatted as nn-nnn-nnnnn-nn-nn with the first 2 numbers designating the state, the second 3 numbers designating the county within the state and the next 5 numbers designating the particular well within the county. When present, the next 2 numbers are a directional sidetrack code to designate the number of horizontal or directional offshoots from a single vertical borehole and the final 2 numbers are an event sequence code used to designate multiple activities conducted at a single well such as recompletion, treatment etc… (A list of the state and county codes can be found at http://www.spwla.org/technical/api-codes)‡).*
5. *Operator Name: This is the name of the company.*
6. *Well Name: This is typically the name of the property owner on whose land the well is located. In the case of multiple property owners pooled under a single unit, the name of the majority*

property owner is often used. The number on the well may designate the chronological sequence of wells drilled. (Example: The Smith #2 might designate the second well drilled on the Smith lease). However, this is not a universal naming convention.

7. *Longitude: This the east-west coordinate location of the well on the earth in degrees, minutes and second.*
8. *Latitude: This is the north-south coordinate location of the well on the earth in degrees, minutes and seconds.*
9. *Latitude/ Longitude Projection: This is the particular projection method for the Latitude/ Longitude (e.g. North American Datum (NAD) 27 or 83)*
10. *True Vertical Depth: This is the absolute depth of the well measured from the surface to the deepest point of penetration.*
11. *Total Water Volume: This is the total amount of water in gallons used as the carrier fluid for the hydraulic fracturing job. It may include recycled water and newly acquired water.*
12. *Production Type: This designates the well type (e.g. Oil, Gas).*

In addition to the general information shown above, each record contains information about the specific chemicals used during the fracturing process. The following is a list of the chemical information shown on the fracturing record:

1. *Trade Name: This is the name of the product designated by the supplier*
2. *Supplier: This is the name of the service company that supplied the product (e.g. Schlumberger, Halliburton)*
3. *Purpose: This is the function served by the additive (Trade Name) in the fracturing process (e.g. surfactant, biocide etc…)*
4. *Ingredients: This is the scientific name of the chemical (e.g. Ethanol, Naphthalene etc…)*
5. *Chemical Abstract Service‡ or CAS Number: This is a number assigned by a division of the American Chemical Society for the purpose of identifying a specific substance. You can learn more about the toxicity characteristics of chemicals by searching for the chemical using the name or CAS number on the USEPA National Center for Computational Toxicology‡ website. USEPA also maintains a Drinking Water Hotline that is available Monday-Friday from 8:30 AM-4:30 PM Eastern time at 1-800-426-4791.*
6. *Ingredient Percentage in Additive by % Mass: This describes the amount of ingredient within the additive (Trade Name) as a percent of the total mass of the additive. Note: Because the %*

Mass of the additive will be expressed as its maximum concentration, the total % Mass of ingredient percentage may exceed 100%.

7. *Ingredient Concentration in HF (Hydraulic fracturing) fluid % by mass: This describes the amount of ingredient as a percent of the total mass of the HF fluid including carrier fluid and additives. Note: The total may not equal 100% due to the absence of non MSDS ingredients which may or may not be listed depending upon state reporting requirements.*

How can my company become a FracFocus participating company and begin entering records?

To become a "FracFocus" participating company please follow the instructions below:

- *Open the website www.hydraulicfracturingdisclosure.org‡*
- *Click on Register in the menu on the right hand side of the home page*
- *Complete the form and submit*
- *Wait for a confirmation e-mail*
- *Establish yourself as a Supervisor and a Data Submitter*
- *Assign other Supervisors and Data Submitters (as necessary)*
- *Download the Excel template*
- *Begin entering and submitting records*

Please note that only 1 representative per company is allowed but any number of supervisors and data submitters can be approved. At present, representatives must work for the company that is to be registered. For security reasons, the system cannot accommodate third party agents.

You can obtain further information about registration and system usage from the Quick How To Guide ‡

Why can't the system show me the information on more than one well at a time?

The purpose of the FracFocus records presentation system was to provide those who may live near a well that has been fractured with information concerning the materials used to fracture the well. All information other than the information used in the search form is available only in an Adobe pdf format. As such, information such as Ingredients, Trade Names and CAS numbers is not available for search or data aggregation purposes.

Are the records from FracFocus available in a digital format such as Excel?

No. FracFocus was originally designed to serve records one at a time in Adobe pdf format in order to ensure accurate, unaltered and uncompromised data. Consequently the chemical information gathered does not currently reside in a database or spreadsheet format.

I know there are wells in my area that have been fractured, but when I search for them I get no results. Why?

The most likely reasons are that either the wells were fractured before January 1, 2011 or they have not yet been entered into the system. Only wells fractured after January 1st will be entered into the system and since the uploading of records began only recently it will take some time before a large number of wells is available. Please keep checking back as wells are added on a daily basis.

The operator name on the well list does not match the name of the operator on the fracturing record. Can you tell me why?

The name of the operator on the well list is based on the name used to register the company in the FracFocus system. However, companies sometimes operate through subsidiaries. For example Anadarko Petroleum Corporation purchased Kerr Mcgee and still operates wells under the Kerr Mcgee name. Regardless of the name of the operator on the fracturing record the operator name on the list reflects the name of the FracFocus participating company.

Where does the water used in hydraulic fracturing come from?

It comes from many sources including surface water bodies such as ponds, lakes, and streams, municipal authorities, groundwater wells, "produced water" (water that comes to the surface during oil and gas production), and re-cycled water from other hydraulic fracturing jobs. Read more...

A term in the website is unfamiliar to me. Where can I go to get more information?

One of the best glossaries of oil and gas terms is available on the web through Schlumberger Inc.‡ You can use the alphabetical listing to select the first letter of the term you are looking for and scroll through the list of terms to find it. This site contains over 4600 oil and gas related terms.

When I go to the Regulations by State page, I don't see the map. What's wrong?

You may have an older version of the Adobe Flash Player installed. You can go to the Adobe site ‡ to download the latest version of the player.

Can hydraulic fracturing fluid migrate into a fresh groundwater zone?

Fracturing fluids can enter a fresh groundwater zone if there is sufficient bottom hole pressure to raise the fluid level from the fractured zone to the fresh groundwater zone, and there is a conduit through which the fluid can flow such as an open annulus between the casing and the formation. Fluids may *also enter fresh groundwater if there is a hole in the casing above the depth of the groundwater zone and the cement outside of the casing is not adequate to prevent fluid flow between the casing and the formation. However, under normal circumstances hydraulic fracturing fluid is confined to the inside of the production casing, the formation being treated and nearby formations.* *Read more...*

What chemicals are being disclosed on this website?

All chemicals that would appear on a Material Safety Data Sheet (MSDS) that are used to hydraulically fracture a well except for those that can be kept proprietary based on the "Trade Secret"‡ provisions related to MSDS found on the Trade Secret link at 1910.1200(i)(1). *Read more...*

How much water is used in hydraulic fracturing?

This varies from well to well and depends upon the well configuration (vertical or horizontal), the number of stages fractured, and the specific characteristics of the formation being fractured. In vertical wells with a single fractured stage it is not uncommon to use less than 50,000 gallons of water during a fracture job, while a multi interval fracture job in a horizontal well can use several million gallons of water. *Read more...*

Is my groundwater safe to use?

This depends upon many factors including:

1. The level of chemicals in the groundwater; whether naturally occurring or introduced. (NOTE: The Maximum Contaminant Level (MCL) for drinking water was established by the EPA and can be found on their website at:*http://water.epa.gov/drink/contaminants/index.cfm* ‡ . *It is important to note, however, that not all chemicals, compounds or elements have an MCL. For example natural gas does not have an MCL; and*

2. Your individual tolerance to some chemicals. While some chemicals such as Benzene can be toxic to everyone in quantities as low as a few parts per billion, the toxicity of other additives depends upon the individual. For example, some people are sensitive to Sodium due to conditions like high blood pressure. Consequently, a tolerable level of sodium for them might be lower than for a person without a similar condition. However, only you and your doctor can determine a safe level of exposure for you. To see a more comprehensive evaluation of chemical toxicity you should visit the website of the U.S. Environmental Protection Agency Integrated Risk Assessment System (IRIS) ‡; and

3. The use to which the groundwater is put (e.g. will it be used for human consumption, livestock consumption, irrigation, washing or bathing etc…).

The best way to determine if your groundwater is fit for its intended use is to have it analyzed by an accredited laboratory for all constituents of concern and to have that analysis evaluated by a qualified professional such as a toxicologist. You can often obtain a list of accredited laboratories from your County Extension Agent, State Water Quality Agency or local Health Department.

<u>Why are chemicals used in hydraulic fracturing?</u>

Chemicals are used for many purposes in hydraulic fracturing. Some chemicals are designed to inhibit bacterial growth. These are called biocides. Others make fluids flow down the casing more easily. These are called friction reducers. Without these and other chemicals, the effectiveness of the fracturing job would be limited. Read more...

<u>How deep is the typical fracture job?</u>

It depends upon the zone being fractured. For example, the following chart shows the area and depths of the 5 predominant shale gas zones in the U.S.

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000
Depth, ft	6, 500 - 8,500	1,000 - 7,000	10,500 - 13,500	4,000 - 8,500	6,000- 11,000

Source: Modern Shale Gas Development in the United States, GWPC, 2009

<u>Do states conduct ongoing testing of water wells and oil and gas well construction?</u>

It depends on the state. When it comes to water wells, many states have water well construction standards but not routine testing requirements. As regards the construction of oil and gas wells, all states have well construction requirements. These can be reviewed by going to the Regulations by State page, selecting the state in question and then selecting View Regulations.

<u>How is water used in hydraulic fracturing?</u>

Water acts as the carrier fluid for the chemical additives and propping agents (typically sand) that are used to fracture the producing formation.

What is Hydraulic Fracturing?

Hydraulic fracturing, commonly referred to as fracing, is the process of creating small cracks, or fractures, in underground geological formations to allow natural gas to flow into the wellbore and on to the surface where the gas is collected and prepared for sale to a wide variety of consumers.
During the fracing process, a mixture of water, sand and other chemical additives designed to protect the integrity of the geological formation and enhance production is pumped under high pressure into the shale formation to create small fractures.

The newly created fractures are "propped" open by the sand, which allows the natural gas to flow into the wellbore where it is collected at the surface and subsequently delivered to a wide range group of consumers. *Read more...*

U.S. Department of Energy • Office of Fossil Energy
National Energy Technology Laboratory

Modern Shale Gas Development in the United States: A Primer

April 2009

Ground Water Protection Council
ALL Consulting
energy · engineering · environmental · planning · technology
NETL
U.S. Department of Energy

DISCLAIMER

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GWPC and ALL Consulting wish to extend their appreciation to the following federal, state, industry, and educational institutions which helped with numerous data sources, data collection and technology reviews that were critical to the success of this project. Additionally, the extra time and energy that individuals provided in reviewing and in broadening our understanding of the issues at hand is respectfully acknowledged.

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FOREWORD

This Primer on Modern Shale Gas Development in the United States was commissioned through the Ground Water Protection Council (GWPC). It is an effort to provide sound technical information on and additional insight into the relationship between today's fastest growing, and sometimes controversial, natural gas resource development activity, and environmental protection, especially water resource management. The GWPC is the national association of state ground water and underground injection agencies whose mission is to promote the protection and conservation of ground water resources for all beneficial uses. One goal of the GWPC is to provide a forum for stakeholder communication on important current issues to foster development of sound policy and regulation that is based on sound science. This Primer is presented in the spirit of furthering that goal.

Water and energy are two of the most basic needs of society. Our use of each vital resource is reliant on and affects the availability of the other. Water is needed to produce energy and energy is necessary to make water available for use. As our population grows, the demands for both resources will only increase. Smart development of energy resources will identify, consider, and minimize potential impacts to water resources.

Natural gas, particularly shale gas, is an abundant U.S. energy resource that will be vital to meeting future energy demand and to enabling the nation to transition to greater reliance on renewable energy sources.

Shale gas development both requires significant amounts of water and is conducted in proximity to valuable surface and ground water. Hence, it is important to reconcile the concurrent and related demands for local and regional water resources, whether for drinking water, wildlife habitat, recreation, agriculture, industrial or other uses.

Because shale gas development in the United States is occurring in areas that have not previously experienced oil and gas production, the GWPC has recognized a need for credible, factual information on shale gas resources, technologies for developing these resources, the regulatory framework under which development takes place, and the practices used to mitigate potential impacts on the environment and nearby communities. While the GWPC's mission primarily concerns water resources, this Primer also addresses non-water issues that may be of interest to citizens, government officials, water supply and use professionals, and other interested parties.

Each state has laws and regulations to ensure the wise use of its natural resources and to protect the environment. The GWPC has conducted a separate study to summarize state oil and gas program requirements that are designed to protect water resources. These two studies complement one other and together provide a body of information that can serve as a basis for fact-based dialogue on how shale gas development can proceed in an environmentally responsible manner under the auspices of state regulatory programs.

This Shale Gas Primer was intended to be an accurate depiction of current factors and does not represent the view of any individual state. Knowledge about shale gas development will continue to evolve. The GWPC welcomes insights that readers may have about the Primer and the relationship of shale gas development to water resources.

Scott R Kell

Scott Kell, President,

Ground Water Protection Council

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EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

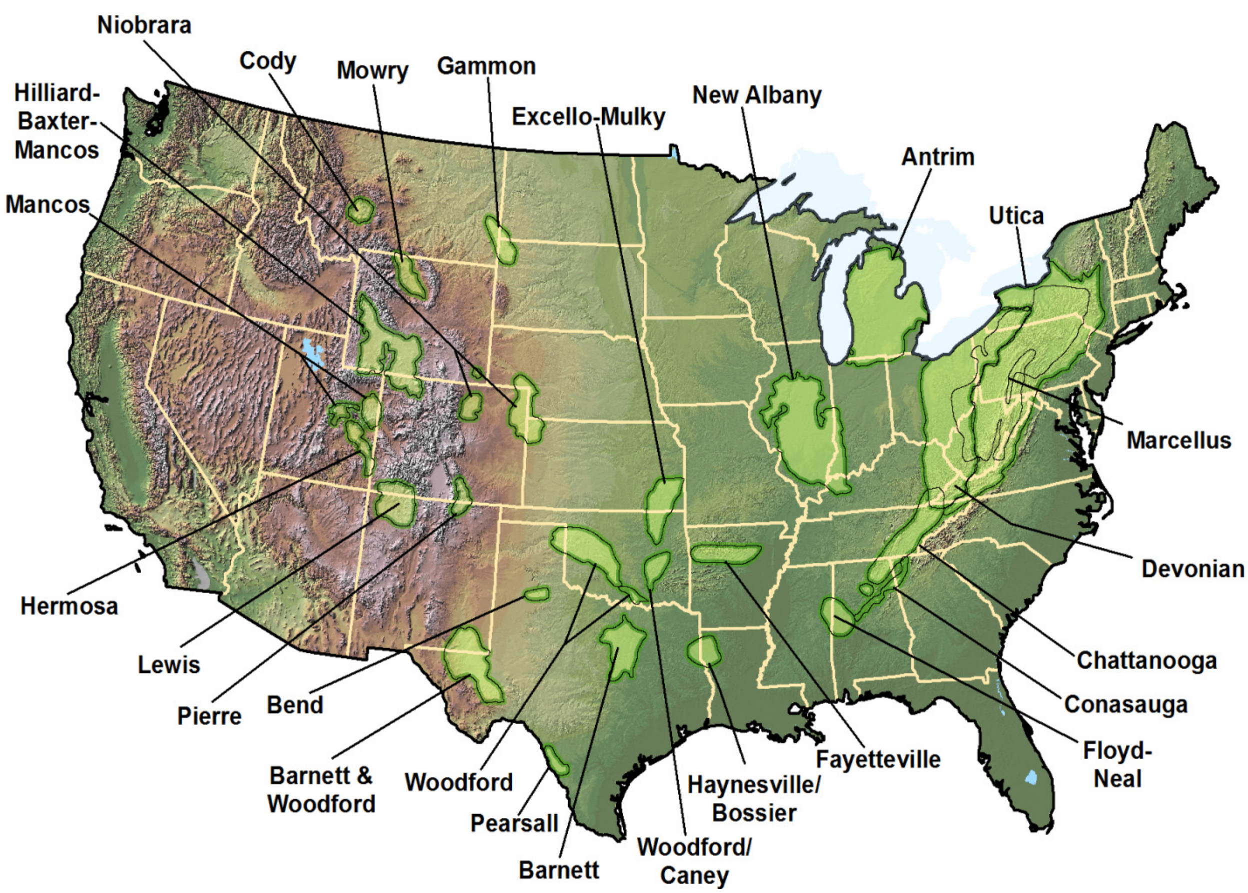
The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

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

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. Exhibit ES-1 shows the approximate locations of current producing gas shales and prospective shales. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

EXHIBIT ES-1: UNITED STATES SHALE BASINS



The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-size-fits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include NO_x, volatile organic compounds, particulate matter, SO_2, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

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TABLE OF CONTENTS

LIST OF EXHIBITS

EXHIBIT

INTRODUCTION

Natural gas production from hydrocarbon-rich shale formations, known as “shale gas”, is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring changes to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

This Primer endeavors to provide much of that information. It describes the importance of shale gas in meeting the future energy needs of the United States (U.S.), including its role in alternative energy strategies and reducing greenhouse gas (GHG) emissions. The Primer provides an overview of modern shale gas development, as well as a summary of federal, state, and local regulations applicable to the natural gas production industry, and describes environmental considerations related to shale gas development.

The Primer is intended to serve as a technical summary document, including geologic information on the shale gas basins in the U.S. and the methods of shale gas development. By providing an overview of the regulatory framework and the environmental considerations associated with shale gas development, it will also help facilitate the minimization and mitigation of adverse environmental impacts. By so doing, the Primer can serve as an instrument to facilitate informed public discussions and to support sound policy-making decisions by government.

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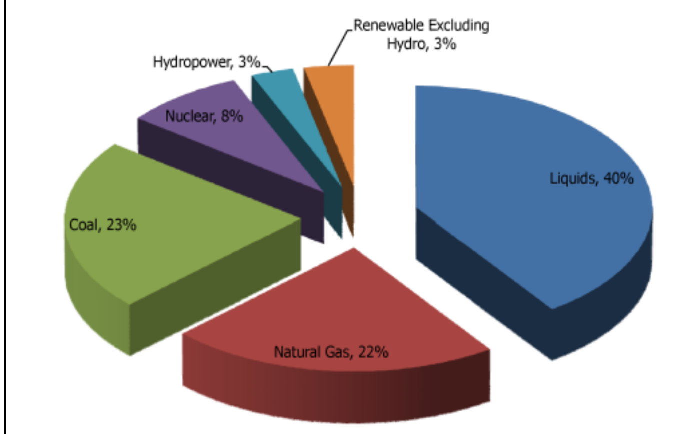
THE IMPORTANCE OF SHALE GAS

The Role of Natural Gas in the United States' Energy Portfolio

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total[1] (Exhibit 1[2]). The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

EXHIBIT 1: UNITED STATES ENERGY CONSUMPTION BY FUEL (2007)



Source: EIA, 2008.

The United States has abundant natural gas resources. The Energy Information Administration (EIA) estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place)[3,4]. Navigant Consulting estimates that technically recoverable unconventional gas (shale gas, tight sands, and coalbed natural gas) accounts for 60% of the onshore recoverable resource[5]. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years[6]. Note that historically, estimates of the size of the total recoverable resource have grown over time as knowledge of the resource has improved and recovery technology has advanced. Unconventional gas resources are a prime example of this trend.

What Is a Tcf?

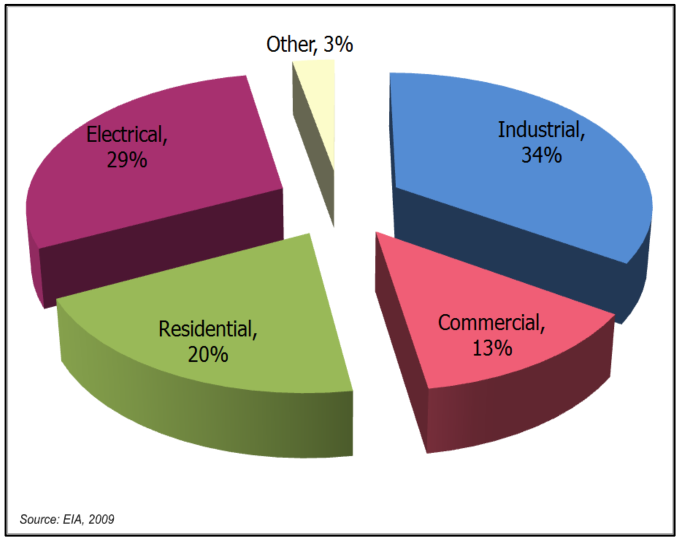
Natural gas is generally priced and sold in units of a thousand cubic feet (Mcf, using the Roman numeral for one thousand). Units of a trillion cubic feet (tcf) are often used to measure large quantities, as in resources or reserves in the ground, or annual national energy consumption. A tcf is one billion Mcf and is enough natural gas to:

- ***Heat 15 million homes for one year;***
- ***Generate 100 billion kilowatt-hours of electricity;***
- ***Fuel 12 million natural gas-fired vehicles for one year.***

Natural gas use is distributed across several sectors of the economy (Exhibit 2[7]). It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating[8]. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come[9].

Natural gas, due to its clean-burning nature and economical availability, has become a very popular fuel for the generation of electricity[10]. In the 1970s and 80s, the choice for the majority of electric utility generators was primarily coal or nuclear power; but, due to economic, environmental, technological, and regulatory changes, natural gas has become the fuel of choice for many new power plants. In 2007, natural gas was 39.1%[11] of electric industry productive capacity.

EXHIBIT 2: NATURAL GAS USE BY SECTOR



Natural gas is also the fuel of choice for a wide range of industries. It is a major fuel source for pulp and paper, metals, chemicals, petroleum refining, and food processing. These five industries alone account for almost three quarters of industrial natural gas use[12] and together employ four million people in the U.S.[13] Natural gas is also a feedstock for a variety of products, including plastics, chemicals, and fertilizers. For many products, there is no economically viable substitute for natural gas. Industrial use of natural gas accounted for 6.63 tcf of demand in 2007 and is expected to grow to 6.82 tcf by 2030.

However, natural gas is being consumed by the U.S. economy at a rate that exceeds domestic production and the gap is increasing[14]. Half of the natural gas consumed today is produced from wells drilled within the last 3.5 years[15]. Despite possessing a large resource endowment, the U.S. consumes natural gas at a rate requiring rapid replacement of reserves. It is estimated that the gap between demand and domestic supply will grow to nearly 9 tcf by the year 2025[16]. However, it is believed by many that unconventional natural gas resources such as shale gas can significantly alter that balance.

Half of the natural gas consumed today is produced from wells drilled within the last 3.5 years.

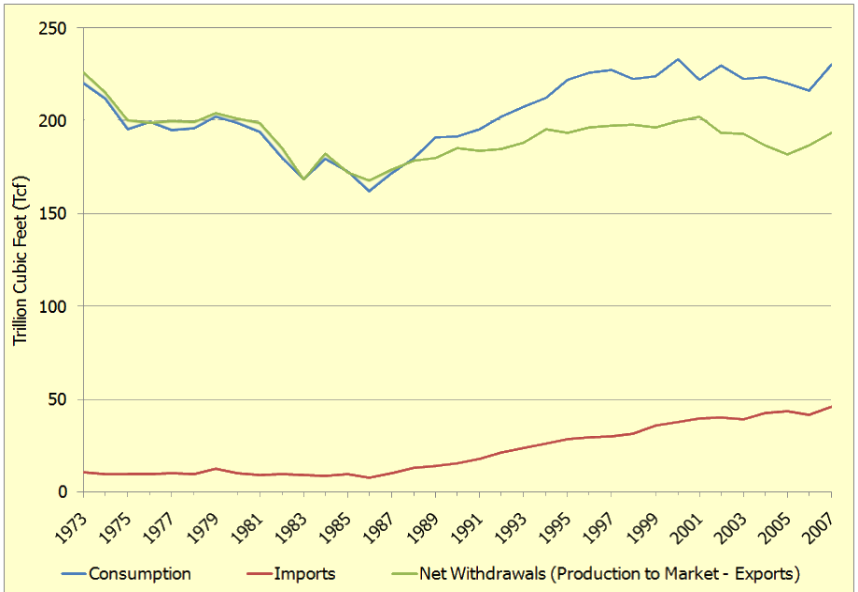
Exhibit 3[17] shows a comparison of production, consumption, and import trends for natural gas in the U.S. with demand increasingly exceeding conventional domestic production. Without domestic shale gas and other unconventional gas production, the gap between demand and domestic production will widen even more, leaving imports to fill the need. Worldwide consumption of natural gas is also increasing; therefore the U.S. can anticipate facing an increasingly competitive market for these imports.

This increased reliance on foreign sources of energy could pose at least two problems for the U.S.: 1) it would serve to decrease our energy security; and 2) it could create a multi-billion dollar outflow to foreign interests, thus making such funds unavailable for domestic investment.

The Advantages of Natural Gas

In the 1800s and early 1900s, natural gas was mainly used to light streetlamps and the occasional house. However, with a vastly improved distribution network and advancements in technology, natural gas is now being used in many ways. One reason for the widespread use of natural gas is its versatility as a fuel. Its high British thermal unit (Btu) content and a well-developed infrastructure make it easy to use in a number of applications.

EXHIBIT 3: COMPARISON OF PRODUCTION, CONSUMPTION AND IMPORT TRENDS FOR NATURAL GAS IN THE UNITED STATES



Source: Modified from EIA, 2008

Another factor that makes natural gas an attractive energy source is its reliability. Eighty-four percent of the natural gas consumed in the U.S. is produced in the U.S., and ninety-seven percent of the gas used in this country is produced in North America[18]. Thus, the supply of natural gas is not dependent on unstable foreign countries and the delivery system is less subject to interruption.

A key advantage of natural gas is that it is efficient and clean burning[19]. In fact, of all the fossil fuels, natural gas is by far the cleanest burning. It emits approximately half the carbon dioxide (CO_2) of coal along with low levels of other air pollutants[20]. The combustion byproducts of natural gas are mostly CO_2 and water vapor, the same compounds people exhale when breathing. Coal and oil are composed of much more complex organic molecules with greater nitrogen and sulfur content. Their combustion byproducts include larger quantities of CO_2, nitrogen oxides (NO_x), sulfur dioxide (SO_2) and particulate ash (Exhibit 4[21]). By comparison, the combustion of natural gas liberates very small amounts of SO_2 and NO_x, virtually no ash, and lower levels of CO_2, carbon monoxide (CO), and other hydrocarbons[22].

EXHIBIT 4: COMBUSTION EMISSIONS (POUNDS/BILLION BTU OF ENERGY INPUT)

Air Pollutant	Combusted Source		
	Natural Gas	Oil	Coal
Carbon dioxide (CO_2)	117,000	164,000	208,000
Carbon monoxide (CO)	40	33	208
Nitrogen oxides (NO_x)	92	448	457
Sulfur dioxide (SO_2)	0.6	1,122	2,591
Particulates (PM)	7.0	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury (Hg)	0.000	0.007	0.016

Sources: EIA, 1998

Because natural gas emits only half as much CO_2 as coal and approximately 30% less than fuel oil, it is generally considered to be central to energy plans focused on the reduction of GHG emissions[23]. According to the EIA in its report "Emissions of Greenhouse Gases in the United States 2006," 82.3% of GHG emissions in the U.S. in 2006 came from CO_2 as a direct result of fossil fuel combustion[24]. Since CO_2 makes up a large fraction of U.S. GHG emissions, increasing the role of natural gas in U.S. energy supply relative to other fossil fuels would result in lower GHG emissions.

Of all the fossil fuels, natural gas is by far the cleanest burning.

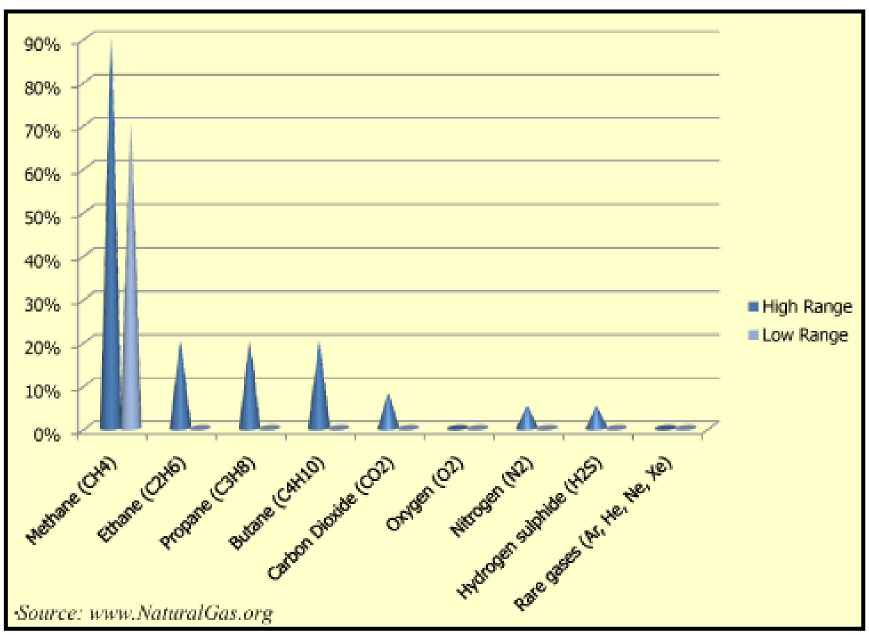
Although there is rapidly increasing momentum to reduce dependence on fossil fuels in the U.S. and elsewhere, the transition to sustainable renewable energy sources will no doubt require considerable time, effort and investment in order for these sources to become economical enough to supply a significant portion of the nation's energy consumption. Indeed, the EIA estimates that fossil fuels (oil, gas, and coal) will supply 82.1% of the nation's energy needs in 2030[25]. Since natural gas is the cleanest burning of the fossil fuels, an environmental benefit could be realized by shifting toward proportionately greater reliance on natural gas until such time as sources of alternative energy are more efficient, economical, and widely available.

Additionally, the march towards sustainable renewable energy sources, such as wind and solar, requires that a supplemental energy source be available when weather conditions and electrical storage capacity prove challenging[26]. Such a backstop energy source must be widely available on near instantaneous demand. The availability of extensive natural gas transmission and distribution pipeline systems makes natural gas uniquely suitable for this role[27]. Thus, natural gas is an integral facet of moving forward with alternative energy options. With the current emphasis on the potential effects of air emissions on global climate change, air quality, and visibility, cleaner fuels like natural gas are an important part of our nation's energy future[28].

Natural Gas Basics

Natural gas is a combination of hydrocarbon gases consisting primarily of methane (CH_4), and lesser percentages of butane, ethane, propane, and other gases[29,30]. It is odorless, colorless, and, when ignited, releases a significant amount of energy[31]. Exhibit 5[32] shows the typical compositional range of natural gas produced in the U.S.

EXHIBIT 5: TYPICAL COMPOSITION OF NATURAL GAS



Natural gas is found in rock formations (reservoirs) beneath the earth's surface; in some cases it may be associated with oil deposits. Exploration and production companies explore for these deposits by using complex technologies to identify prospective drilling locations. Once extracted, the natural gas is processed to eliminate other gases, water, sand, and other impurities. Some hydrocarbon gases, such as butane and propane, are captured and separately marketed. Once it has been processed, the cleaned natural gas is distributed through a system of pipelines across thousands of miles[33]. It is through these pipelines that natural gas is transported to its endpoint for residential, commercial, and industrial use.

Natural gas is measured in either volumetric or energy units. As a gas, it is measured by the volume it displaces at standard temperatures and pressures, usually expressed in cubic feet. Gas companies generally measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or billions of cubic feet (bcf), and estimate resources such as original gas-in-place in trillions of cubic feet (tcf).

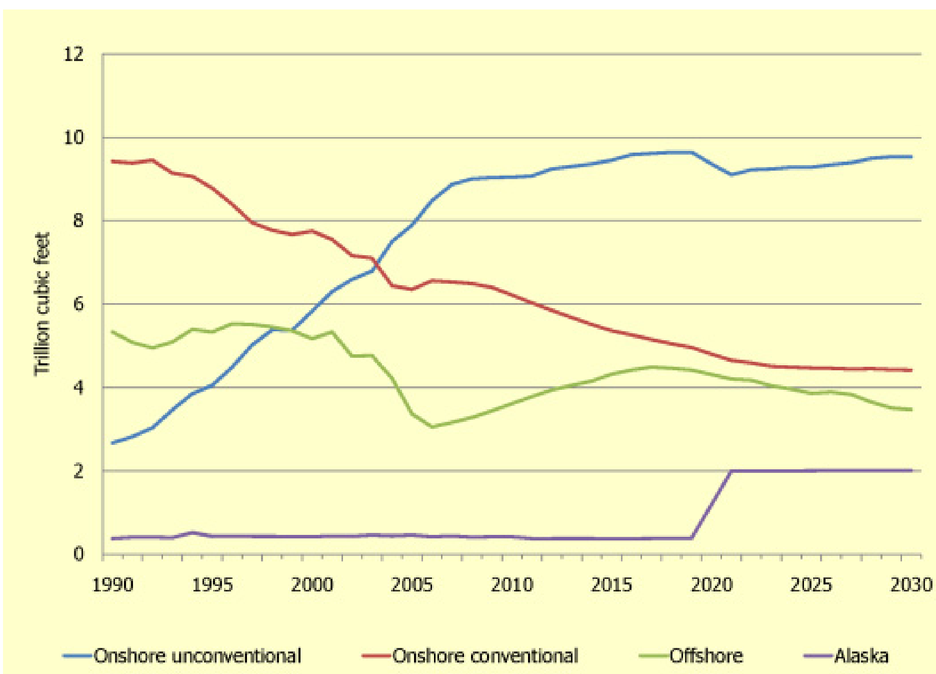
Calculating and tracking natural gas by volume is useful, but it can also be measured as a source of energy. Similar to other forms of energy, natural gas can be computed and presented in British thermal units (Btu). One Btu is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at normal pressure[34]. There are about 1,000 Btus in one cubic foot of natural gas delivered to the consumer[35]. Natural gas distribution companies typically measure the gas delivered to a residence in 'therms' for billing purposes[36]. A therm is equal to 100,000 Btus—approximately 100 cubic feet—of natural gas[37].

Unconventional Gas

The U.S. increased its natural gas reserves by 6% from 1970 to 2006, producing approximately 725 tcf of gas during that period[38]. This increase is primarily a result of advancements in technology, resulting in an increase in economically recoverable reserves (reserves becoming proven) that were previously thought to be uneconomic[39].

In 2007, Texas, Wyoming, and Colorado were the states with the greatest additions to proved gas reserves for the year; these additions were from shale gas, tight sands, and coalbed methane, all of which are unconventional gas plays[40]. Similarly, the states of Texas (30%) and Wyoming (12%) had the greatest volume of proved gas

EXHIBIT 6: NATURAL GAS PRODUCTION BY SOURCE (TCF/YEAR)



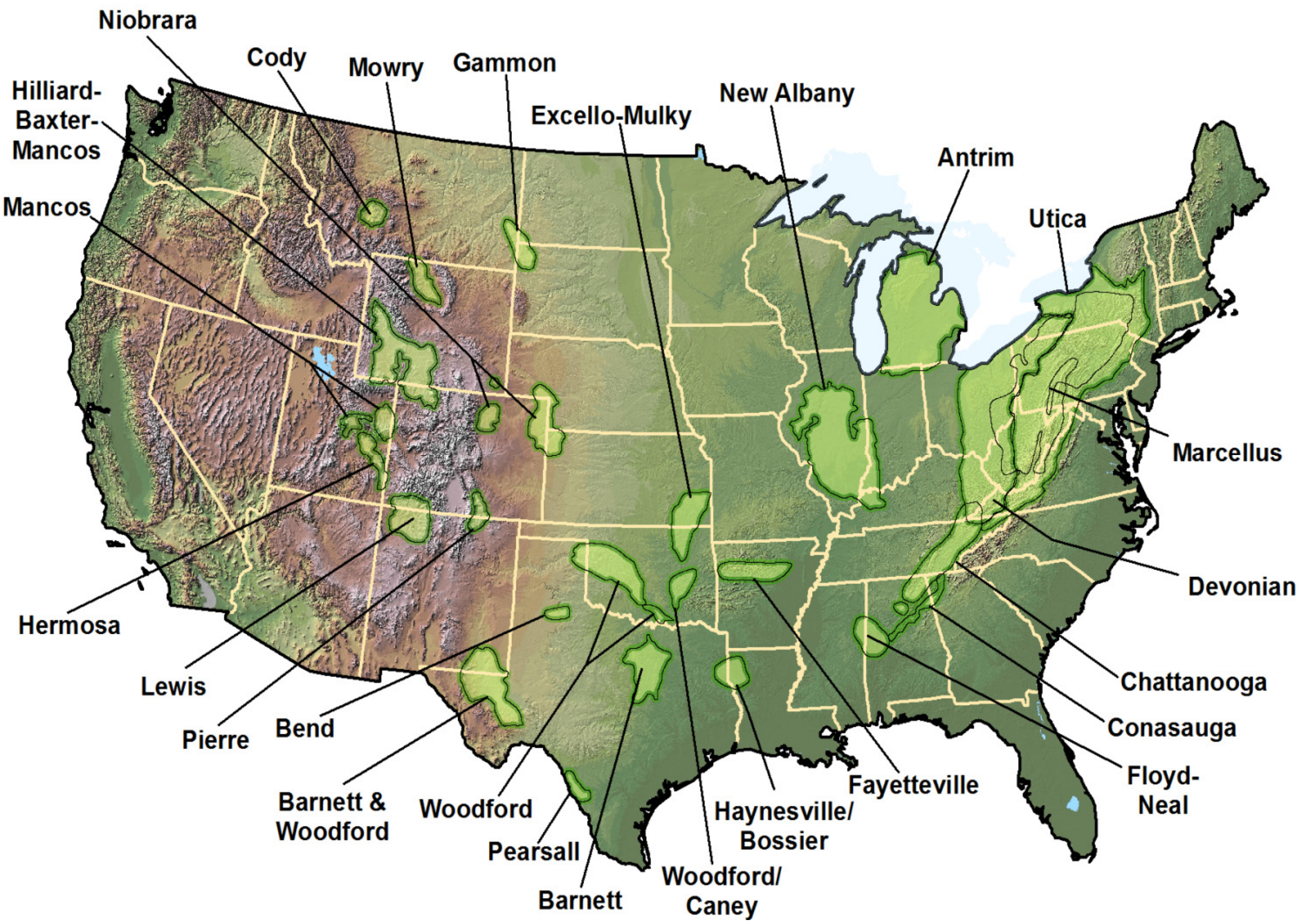
Source: EIA, 2008

reserves in the U.S. in 2007—again, both primarily as a result of developing unconventional natural gas plays[41].

Unconventional production now accounts for 46% of the total U.S. production.

Overall, unconventional natural gas is anticipated to become an ever-increasing portion of the U.S. proved reserves, while conventional gas reserves are declining[42]. Over the last decade, production from unconventional sources has increased almost 65%, from 5.4 trillion cubic feet per year (tcf/yr) in 1998 to 8.9 tcf/yr in 2007 (Exhibit 6). This means unconventional production now accounts for 46% of the total U.S. production[43].

EXHIBIT 7: UNITED STATES SHALE GAS BASINS

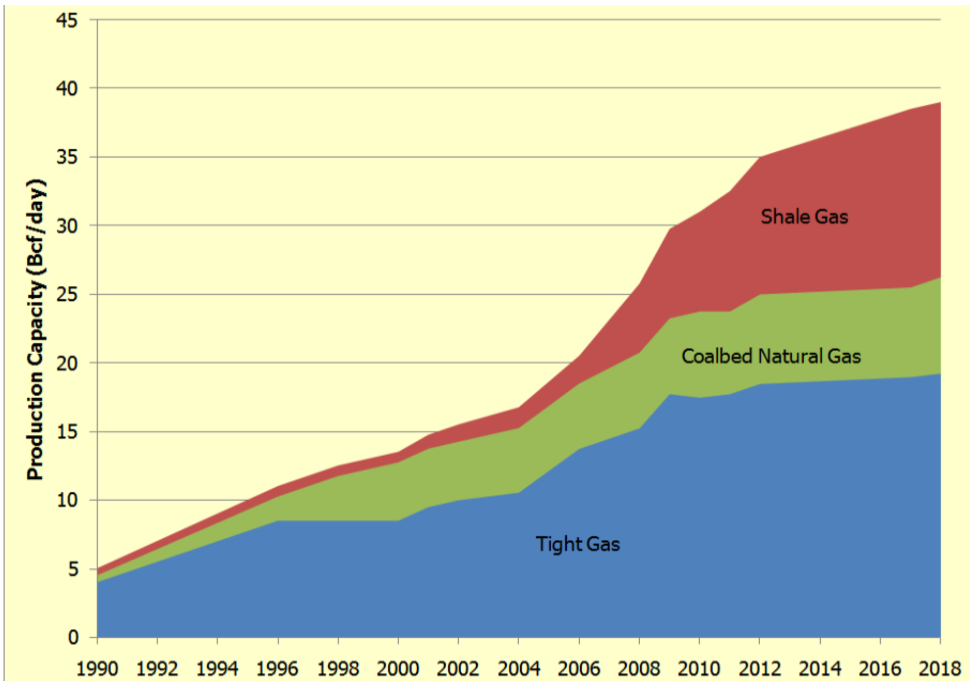


Source: ALL Consulting, Modified from USGS & other sources

The Role of Shale Gas in Unconventional Gas

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas (Exhibit 7[44]). Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 states[45]. Improved drilling and fracturing technologies have contributed considerably to the economic potential of shale gas. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook. Exhibit 8[46] shows the projected contribution of shale gas to the overall unconventional gas production in the U.S. in bcf/day.

EXHIBIT 8: UNITED STATES UNCONVENTIONAL GAS OUTLOOK (BCF/DAY)



Source: Modified from American Clean Skies, Summer 2008

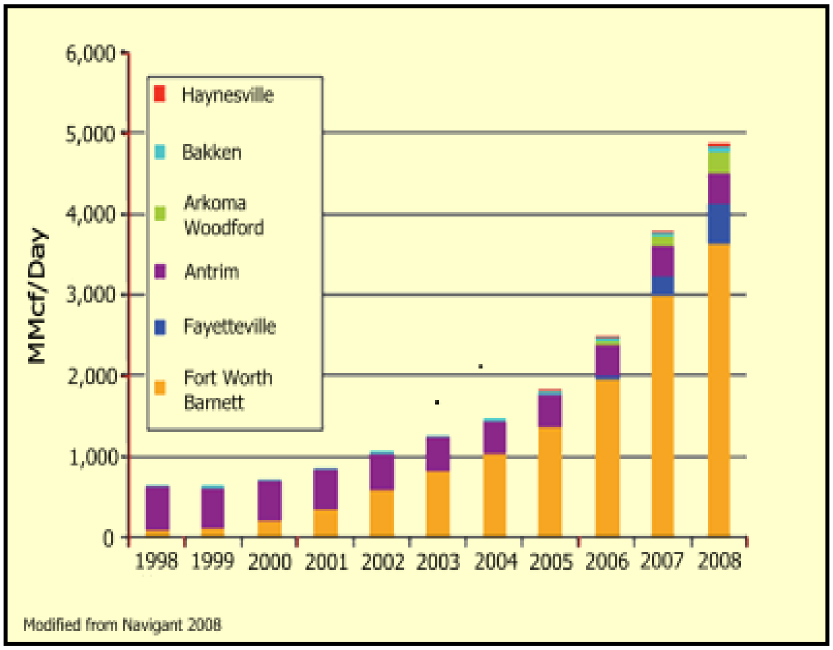
Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Advances in the pre-existing technologies of directional drilling and hydraulic fracturing set the stage for today's horizontal drilling and fracturing techniques, without which many of the unconventional natural gas plays would not be economical. As recently as the late 1990s, only 40 drilling rigs (6% of total active rigs in the U.S.) in the U.S. were capable of onshore horizontal drilling; that number grew to 519 rigs (28% of total active rigs in the U.S.) by May 2008[47].

It has been suggested that the rapid growth of unconventional natural gas plays has not been captured by recent resource estimates compiled by the EIA and that, therefore, their resource estimates do not accurately reflect the contribution of shale gas[48]. Since 1998, annual production has consistently exceeded the EIA's forecasts of unconventional gas production. A great deal of this increase is attributable to shale gas production, particularly from the Barnett Shale in Texas. The potential for most other shale gas plays in the U.S. is just emerging. Taking this into consideration, Navigant, adding their own analysis of shale gas resources to other national resource estimates, has estimated that U.S. total natural gas resources (proved plus unproved technically recoverable) are 1,680 tcf to 2,247 tcf, or 87 to 116 years of production at 2007 U.S. production levels. This compares with EIA's national

Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices.

resource estimate of 1,744 tcf, which is within the Navigant range. Navigant has estimated that shale gas comprises 28% or more of total estimated technically recoverable gas resources in the U.S.[49]. Exhibit 9[50] depicts the daily production (in MMcf/day) from each of the currently active shale gas plays.

EXHIBIT 9: TRENDS IN SHALE GAS PRODUCTION (MMCF/DAY)



As with most resource estimates, especially emerging resources such as unconventional natural gas, these estimates are likely to change over time. In addition, there are a variety of organizations making resource and future production estimates for shale gas. These analyses use different assumptions, data, and methodologies. Therefore, one may come across a wide range of numbers for projected shale gas recovery, both nationally and by basin. These shale gas resource estimates are likely to change as new information, additional experience, and advances in technology become available.

Shale gas resource estimates are likely to change as new information, additional experience, and advances in technology become available.

Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs[51]. The total recoverable gas resources from 4 emerging shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf[52]. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. An additional benefit of shale gas plays is that many exist in areas previously developed for natural gas production and, therefore, much of the necessary pipeline infrastructure is already in place. Many of these areas are also proximal to the nation's population centers thus potentially facilitating transportation to consumers. However, additional pipelines will have to be built to access development in areas that have not seen gas production before[53].

Looking Forward

Considering natural gas's clean-burning nature, the nation's domestic natural gas resources, and the presence of supporting infrastructure, the development of domestic shale gas reserves will be an important component of the U.S.'s energy portfolio for many years. Recent successes in a variety of geologic basins have created the opportunity for shale gas to be a strategic part of the nation's energy and economic growth[54].

Recent successes and improvements in a variety of geologic basins have created the opportunity for shale gas to be a strategic part of the nation's energy and economic growth.

The Environmental Considerations section of this Primer describes how improvements in horizontal drilling and hydraulic fracturing technologies have opened the door to the economic recovery of shale gas. It also discusses additional practices that have allowed development of areas that might previously have been inaccessible due to environmental constraints or restrictions on disturbances in both urban and rural settings. By using horizontal drilling, operators have been able to reduce the extent of surface impact commonly associated with multiple vertical wells drilled from multiple well pads; equivalent well coverage can be achieved through drilling fewer horizontal wells from a single well pad. This can result in a significant reduction in surface disturbances: fewer well pads, fewer roads, reduced traffic, fewer pipelines, and fewer surface facilities. In urban settings, this can mean less impact on nearby populations and businesses. In rural settings, this can mean fewer consequences for wildlife habitats, agricultural resources, and surface water bodies.

Other practices that are now commonly used for drilling, particularly in urban settings, include: the use of sound walls and blankets to reduce noise, the use of directional or shielded lighting to reduce nighttime disturbance to nearby residences and businesses, the use of pipelines to transport water resulting in reduced truck traffic, and the use of solar-powered telemetry devices to monitor gas production resulting in reduced personnel visits to well sites. Such practices are used in specific locations or situations that call for them, and are not appropriate everywhere, but where needed, they provide opportunities for safe, environmentally sound development that may not have been possible without them.

These technologies and practices, along with the increasing gas prices of the last few years, have provided the means by which shale gas can be economically recovered. Improvements in reducing the overall footprint and level of disturbance from drilling and completion activities have provided the industry with the methods for moving forward with development in new areas that were previously inaccessible.

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SHALE GAS DEVELOPMENT IN THE UNITED STATES

Shale formations across the U.S. have been developed to produce natural gas in small but continuous volumes since the earliest years of gas development. The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York[55]. The natural gas from this first well was used by town residents for lighting[56]. Early supplies of natural gas were derived from shallow gas wells that were not complicated to drill and from natural gas seeps[57]. The shallow wells and seeps were capable of producing small amounts of natural gas that were used for illuminating city streets and households[58]. These early gas wells played a key part in bringing illumination to the cities and towns of the eastern U.S.[59].

The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York.

Other shale gas wells followed the Fredonia well with the first field-scale development of shale gas from the Ohio Shale in the Big Sandy Field of Kentucky during the 1920s[60]. The Big Sandy Field has recently experienced a renewed growth and currently is a 3,000-square-mile play encompassing five counties[61]. By the 1930s, gas from the Antrim Shale in Michigan had experienced moderate development; however, it was not until the 1980s that development began to expand rapidly to the point that it has now reached nearly 9,000 wells[62]. It was also during the 1980s that one of the nation's most active natural gas plays initially kicked off in the area around Fort Worth, Texas[63]. The play was the Barnett Shale, and its success grabbed the industry's attention. Large-scale hydraulic fracturing, a process first developed in Texas in the 1950s, was first used in the Barnett in 1986; likewise, the first Barnett horizontal well was drilled in 1992[64]. Through continued improvements in the techniques and technology of hydraulic fracturing, development of the Barnett Shale has accelerated[65]. In the ensuing two decades, the science of shale gas extraction has matured into a sophisticated process that utilizes horizontal drilling and sequenced, multi-stage hydraulic fracturing technologies. As the Barnett Shale play has matured, natural gas producers have been looking to extrapolate the lessons learned in the Barnett to the other shale gas formations present across the U.S. and Canada[66].

In addition to the Barnett Play, a second shale play with greater oil production has also been advancing techniques related to horizontal wells and hydraulic fracturing. The Bakken Shale of the Williston Basin of Montana and North Dakota has seen a similar growth rate to the Barnett. The Bakken is another technical play in which the development of this unconventional resource has benefitted from the technological advances in horizontal wells and hydraulic fracturing[67]. In April 2008, the United States Geological Survey (USGS) released an updated assessment of the undiscovered technically recoverable reserves for this shale play estimating there are 3.65 billion barrels (bbls) of oil, 1.85 tcf of associated natural gas, and 148 million bbls of natural gas liquids in the play[68].

The combination of sequenced hydraulic fracture treatments and horizontal well completions has been crucial in facilitating the expansion of shale gas development. Prior to the successful application of these two technologies in the Barnett Shale, shale gas resources in many basins had been overlooked because production was not viewed as economically feasible[69]. The low natural permeability of shale has been the limiting factor to the production of shale gas resources because it only allows minor volumes of gas to flow naturally to a wellbore[70]. The characteristic of low-matrix permeability represents a key difference between shale and other gas reservoirs. For gas shales to be economically produced, these restrictions must be overcome[71]. The combination of reduced economics and low permeability of gas shale formations historically caused operators to bypass these formations and focus on other resources[72].

Shale Gas – Geology

Shale gas is natural gas produced from shale formations that typically function as both the reservoir and source for the natural gas. In terms of its chemical makeup, shale gas is typically a dry gas primarily composed of methane (90% or more methane), but some formations do produce wet gas. The Antrim and New Albany formations have typically produced water and gas[73]. Gas shales are organic-rich shale formations that were previously regarded only as source rocks and seals for gas accumulating in the stratigraphically-associated sandstone and carbonate reservoirs of traditional onshore gas development[74]. Shale is a sedimentary rock that is predominantly comprised of consolidated clay-sized particles. Shales are deposited as mud in low-energy depositional environments such as tidal flats and deep water basins where the fine-grained clay particles fall out of suspension in these quiet waters. During the deposition of these very fine-grained sediments, there can also be deposition of organic matter in the form of algae-, plant-, and animal-derived organic debris[75]. The naturally tabular clay grains tend to lie flat as the sediments accumulate and subsequently become compacted as a result of additional sediment deposition. This results in mud with thin laminar bedding that lithifies (solidifies) into thinly layered shale rock. The very fine sheet-like clay mineral grains and laminated layers of sediment result in a rock that has limited horizontal permeability and extremely limited vertical permeability. Typical unfractured shales have matrix permeabilities on the order of 0.01 to 0.00001 millidarcies[76]. This low permeability means that gas trapped in shale cannot move easily within the rock except over geologic expanses of time (millions of years).

EXHIBIT 10: MARCELLUS SHALE OUTCROP

Source: ALL Consulting, 2008

The natural layering and fracturing of shales can be seen in outcrop. Exhibit 10 shows a typical shale outcrop which reveals the natural bedding planes, or layers, of the shale and near-vertical natural fractures that can cut across the naturally horizontal bedding planes. Although the vertical fractures shown in this picture are naturally occurring, artificial fractures induced by hydraulic fracture stimulation in the deep subsurface reservoir rock would have a similar appearance.

The low permeability of shale causes it to be classified as an unconventional reservoir for gas (or in some cases, oil) production. These low permeability, often organic-rich units are also thought to be the source beds for much of the hydrocarbons produced in these basins[77]. Gas reservoirs are classified as conventional or unconventional for the following reasons:

1. **Conventional reservoirs** – Wells in conventional gas reservoirs produce from sands and carbonates (limestones and dolomites) that contain the gas in interconnected pore spaces that allow flow to the wellbore. Much like a kitchen sponge, the gas in the pores can move from one pore to another through smaller pore-throats that create permeable flow through the reservoir. In conventional natural gas reservoirs, the gas is often sourced from organic-rich shales proximal to the more porous and permeable sandstone or carbonate.

2. **Unconventional reservoirs** – Wells in unconventional reservoirs produce from low permeability (tight) formations such as tight sands and carbonates, coal, and shale. In unconventional gas reservoirs, the gas is often sourced from the reservoir rock itself (tight gas sandstone and carbonates are an exception). Because of the low permeability of these formations, it is typically necessary to stimulate the reservoir to create additional permeability. Hydraulic fracturing of a reservoir is the preferred stimulation method for gas shales. Differences between the three basic types of unconventional reservoirs include:

    1. **Tight Gas –** Wells produce from regional low-porosity sandstones and carbonate reservoirs. The natural gas is sourced (formed) outside the reservoir and migrates into the reservoir over time (millions of years)[78]. Many of these wells are drilled horizontally and most are hydraulically fractured to enhance production.

    2. **Coal Bed Natural Gas** (CBNG) – Wells produce from the coal seams which act as source and reservoir of the natural gas[79]. Wells frequently produce water as well as natural gas. Natural gas can be sourced by thermogenic alterations of coal or by biogenic action of indigenous microbes on the coal. There are some horizontally drilled CBNG wells and some that receive hydraulic fracturing treatments. However, some CBNG reservoirs are also underground sources of drinking water and as such there are restrictions on hydraulic fracturing. CBNG wells are mostly shallow as the coal matrix does not have the strength to maintain porosity under the pressure of significant overburden thickness.

    3. **Shale Gas** – Wells produce from low permeability shale formations that are also the source for the natural gas. The natural gas volumes can be stored in a local macro-porosity system (fracture porosity) within the shale, or within the micro-pores of the shale[80], or it can be adsorbed onto minerals or organic matter within the shale[81]. Wells may be drilled either vertically or horizontally and most are hydraulically fractured to stimulate production. Shale gas wells can be similar to other conventional and unconventional wells in terms of depth, production rate, and drilling.

Sources of Natural Gas

Shale gas is both created and stored within the shale bed. Natural gas (methane) is generated from the organic matter that is deposited with and present in the shale matrix.

In order for a shale to have economic quantities of gas it must be a capable source rock. The potential of a shale formation to contain economic quantities of gas can be evaluated by identifying specific source rock characteristics such as total organic carbon (TOC), thermal maturity, and kerogen analysis. Together, these factors can be used to predict the likelihood of the prospective shale to produce economically viable volumes of natural gas. A number of wells may need to be analyzed in order to sufficiently characterize the potential of a shale formation, particularly if the geologic basin is large and there are variations in the target shale zone.

Shale Gas in the United States

Shale gas is present across much of the lower 48 States. Exhibit 7 shows the approximate locations of current producing gas shales and prospective shales. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. The following discussion provides a summary of basic information regarding these shale gas plays.

Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique challenges. For example, the Antrim and New Albany Shales are shallower shales that produce significant volumes of formation water unlike most of the other gas shales. Development of the Fayetteville Shale is occurring in rural areas of north central Arkansas, while development of the Barnett Shale is focused in the area of Forth Worth, Texas, in an urban and suburban environment.

Key Gas Resource Terms

Proved Reserves: *That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.*

Technically Recoverable Resources: *The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.*

Original Gas-In-Place: *The entire volume of gas contained in the reservoir, regardless of the ability to produce it.*

As new technologies are developed and refined, shale gas plays once believed to have limited economic viability are now being re-evaluated. Exhibit 11 summarizes the key characteristics of the most active shale gas plays across the U.S. This exhibit supplies data related to the character of the shale and also provides a means to compare some of the key characteristics that are used to evaluate the different gas shale basins. Note that estimates of the shale gas resource, especially the portion that is technically recoverable, are likely to increase over time as new data become available from additional drilling, as experience is gained in producing shale gas, as understanding of the resource characteristics increases, and as recovery technologies improve.

EXHIBIT 11: COMPARISON OF DATA FOR THE GAS SHALES IN THE UNITED STATES

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6, 500 - 8,500[82]	1,000 - 7,000[83]	10,500 - 13,500[84]	4,000 - 8,500[85]	6,000 - 11,000[86]	600 - 2,200[87]	500 - 2,000[88]
Net Thickness, ft	100 - 600[89]	20 - 200[90]	200[91] - 300[92]	50 - 200[93]	120 - 220[94]	70 - 120[95]	50 - 100[96]
Depth to Base of Treatable Water#, ft	~1200	~500[97]	~400	~850	~400	~300	~400
Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5[98]	4.0 - 9.8[99]	0.5 - 4.0[100]	3 - 12[101]	1 - 14[102]	1 - 20[103]	1 - 25[104]
Total Porosity, %	4 - 5[105]	2 - 8[106]	8 - 9[107]	10[108]	3 - 9[109]	9[110]	10 - 14[111]
Gas Content, scf/ton	300 - 350[112]	60 - 220[113]	100 - 330[114]	60 - 100[115]	200 - 300[116]	40 - 100[117]	40 - 80[118]
Water Production, Barrels water/day	N/A	N/A	N/A	N/A	N/A	5 - 500[119]	5 - 500[120]
Well spacing, acres	60 - 160[121]	80 - 160	40 - 560[122]	40 - 160[123]	640[124]	40 - 160[125]	80[126]
Original Gas-In-Place, tcf[127]	327	52	717	1,500	23	76	160
Technically Recoverable Resources, tcf[128]	44	41.6	251	262	11.4	20	19.2

NOTE: Information presented in this table, such as Original Gas-in-Place and Technically Recoverable Resources, is presented for general comparative purposes only. The numbers provided are based on the sources shown and this research did not include a resource evaluation. Rather, publically available data was obtained from a variety of sources and is presented for general characterization and comparison. Resource estimates for any basin may vary greatly depending on individual company experience, data available at the time the estimate was performed, and other factors. Furthermore, these estimates are likely to change as production methods and technologies improve.

Mcf = thousands of cubic feet of gas
scf = standard cubic feet of gas
tcf = trillions of cubic feet of gas
# = For the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.
N/A = Data not available

The Barnett Shale

The Barnett Shale is located in the Fort Worth Basin of north-central Texas. It is a Mississippian-age shale occurring at a depth of 6,500 feet to 8,500 feet (Exhibit 11 and Exhibit 13[131]) and is bounded by limestone formations above (Marble Falls Limestone) and below (Chappel Limestone) (Exhibit 12).

With over 10,000 wells drilled to date, the Barnett Shale is the most prominent shale gas play in the U.S.[132]. It has been a showcase for modern tight-reservoir development typical of gas shales in the U.S.[133]. The development of the Barnett Shale has been a proving ground for combining the technologies of horizontal drilling and large-volume hydraulic fracture treatments. Drilling operations continue expanding the play boundaries outward; at the same time, operations have turned towards infill drilling to increase the amount of gas recovered[134]. Horizontal well completions in the Barnett are occurring at well spacing ranging from 60 to 160 acres per well (Exhibit 11).

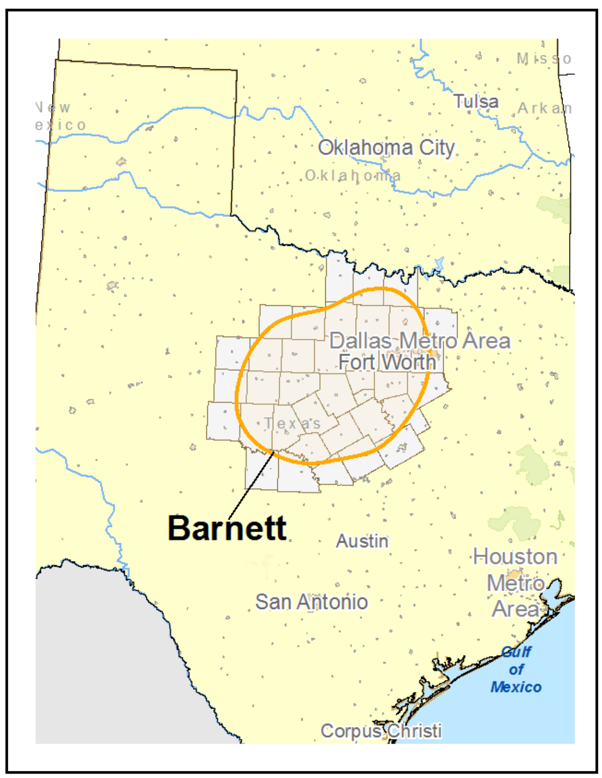
The Barnett Shale covers an area of about 5,000 square miles with an approximate thickness ranging from 100 feet (ft) to more than 600 ft (Exhibit 11). The original gas-in-place estimate for the Barnett Shale is 327 tcf with estimated technically recoverable resources of 44 tcf (Exhibit 11). The gas content is the highest among the major shale plays, ranging from 300 standard cubic feet per ton (scf/ton) to 350 scf/ton of rock (Exhibit 11).

EXHIBIT 12: STRATIGRAPHY OF THE BARNETT SHALE

Period			Group/Unit
Permian		Leonardian	Clear Fork Grp
			Wichita Grp
		Wolfcampian	Cisco Grp
Pennsylvanian		Virgilian	
		Missourian	Canyon Grp
		Desmoinesian	Strawn Grp
		Atokan	Bend Grp Marble Falls Limestone
		Morrowan	
Mississippian		Chesterian - Meramecian	Barnett Shale
		Osagean	
			Chappel Limestone
Ordovician			Viola Limestone
		Canadian	Simpson Grp Ellenburger Grp

Source: Hayden and Pursell, 2005[129]
AAPG, 1987 [130]

EXHIBIT 13: BARNETT SHALE IN THE FORT WORTH BASIN



Source: ALL Consulting, 2009

The Fayetteville Shale

The Fayetteville Shale is situated in the Arkoma Basin of northern Arkansas and eastern Oklahoma over a depth range of 1,000 ft to 7,000 ft (Exhibit 15[135] and Exhibit 11). The Fayetteville Shale is a Mississippian-age shale bounded by limestone (Pitkin Limestone) above and sandstone (Batesville Sandstone) below (Exhibit 14).

Development of the Fayetteville began in the early 2000s as gas companies that had experienced success in the Barnett Shale of the Fort Worth Basin identified parallels between it and the Mississippian-aged Fayetteville Shale in terms of age and geologic character[136]. Lessons learned from the horizontal drilling and hydraulic fracturing techniques employed in the Barnett, when adapted to development of the Fayetteville Shale, made this play economical[137]. Between 2004 and 2007 the number of gas wells drilled annually in the Fayetteville shale jumped from 13 to more than 600, and gas production for the shale increased from just over 100 MMcf/yr to approximately 88.85 bcf/yr[138]. With over 1,000 wells in production to date, the Fayetteville Shale is currently on its way to becoming one of the most active plays in the U.S.[139].

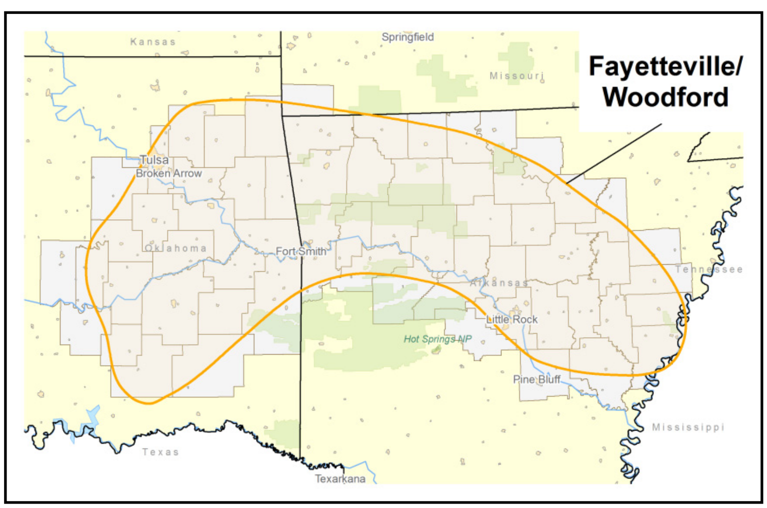
The area of the Fayetteville Shale play is nearly double that of the Barnett Shale at 9,000 square miles, with well spacing ranging from 80 to 160 acres per well, and pay zone thickness averaging between 20 ft and 200 ft (Exhibit 11). The gas content for the Fayetteville Shale has been measured at 60 to 220 scf/ton, which is less than the 300 to 350 scf/ton gas content of the Barnett. The lower gas content of the Fayetteville, as compared to the Barnett, results in lower estimates of the original gas-in-place and technically recoverable resources: 52 tcf and 41.6 tcf respectively (Exhibit 11).

EXHIBIT 14: STRATIGRAPHY OF THE FAYETTEVILLE SHALE

Period		Group/Unit	
CARBONIFEROUS	Pennsylvanian	Atoka	
		Bloyd	
		Hale	Prairie Grove
			Cane Hill
	Mississippian	(IMO)	
		Pitkin	
		Fayetteville	
		Batesville	
		Moorefield	
		Boone	

Source: Hillwood, 2007[140]

EXHIBIT 15: FAYETTEVILLE SHALE IN THE ARKOMA BASIN



Source: ALL Consulting, 2009

The Haynesville Shale

The Haynesville Shale (also known as the Haynesville/Bossier) is situated in the North Louisiana Salt Basin in northern Louisiana and eastern Texas with depths ranging from 10,500 ft to 13,500 ft (Exhibit 17[141] and Exhibit 11). The Haynesville is an Upper Jurassic-age shale bounded by sandstone (Cotton Valley Group) above and limestone (Smackover Formation) below (Exhibit 16).

In 2007, after several years of drilling and testing, the Haynesville Shale made headlines as a potentially significant gas reserve, although the full extent of the play will only be known after several more years of development are completed[142].

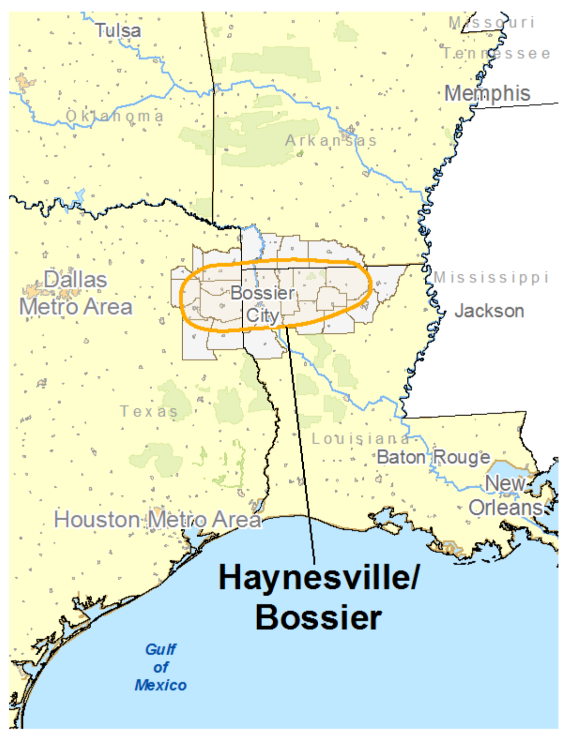
The Haynesville Shale covers an area of approximately 9,000 square miles with an average thickness of 200 ft to 300 ft (Exhibit 11). The thickness and areal extent of the Haynesville has allowed operators to evaluate a wider variety of spacing intervals ranging from 40 to 560 acres per well (Exhibit 11). Gas content estimates for the play are 100 scf/ton to 330 scf/ton. The Haynesville formation has the potential to become a significant shale gas resource for the U.S. with original gas-in-place estimates of 717 tcf and technically recoverable resources estimated at 251 tcf (Exhibit 11).

EXHIBIT 16: STRATIGRAPHY OF THE HAYNESVILLE SHALE

Period		Group/Unit
Cretaceous		Navarro
		Taylor
		Austin
		Eagle Ford
		Tuscaloosa
		Washita
		Fredericksburg
		Trinity Group
		Nuevo Leon
Jurassic	Upper	Cotton Valley Group
		Haynesville
		Smackover
		Norphlet
	Middle	Louann
	Lower	Werner
Triassic	Upper	Eagle Mills

Source: Johnson, et al., 2000[143]

EXHIBIT 17: HAYNESVILLE SHALE IN THE TEXAS & LOUISIANA BASIN



Source: ALL Consulting, 2009

The Marcellus Shale

The Marcellus Shale is the most expansive shale gas play, spanning six states in the northeastern U.S. (Exhibit 19[144]). The estimated depth of production for the Marcellus is between 4,000 ft and 8,500 ft (Exhibit 11). The Marcellus Shale is a Middle Devonian-age shale bounded by shale (Hamilton Group) above and limestone (Tristates Group) below (Exhibit 18).

Following an increase in gas prices, triggered by the Natural Gas Policy Act (NGPA) of 1978, Devonian shale gas development rose in the early- to mid-1980s in the northeast, but decreasing gas prices resulted in uneconomical wells and declining production through the 1990s[145]. In 2003, Range Resources Corporation drilled the first economically producing wells into the Marcellus formation in Pennsylvania using horizontal drilling and hydraulic fracturing techniques similar to those used in the Barnett Shale formation of Texas[146]. Range Resources began producing this formation in 2005. As of September 2008, there were a total of 518 wells permitted in Pennsylvania in the Marcellus shale and 277 of the approved wells had been drilled[147].

The Marcellus Shale covers an area of 95,000 square miles at an average thickness of 50 ft to 200 ft (Exhibit 11). While the Marcellus is lower in relative gas content at 60 scf/ton to 100 scf/ton, the much larger area of this play compared to the other shale gas plays results in a higher original gas-in-place estimate of up to 1,500 tcf (Exhibit 11).

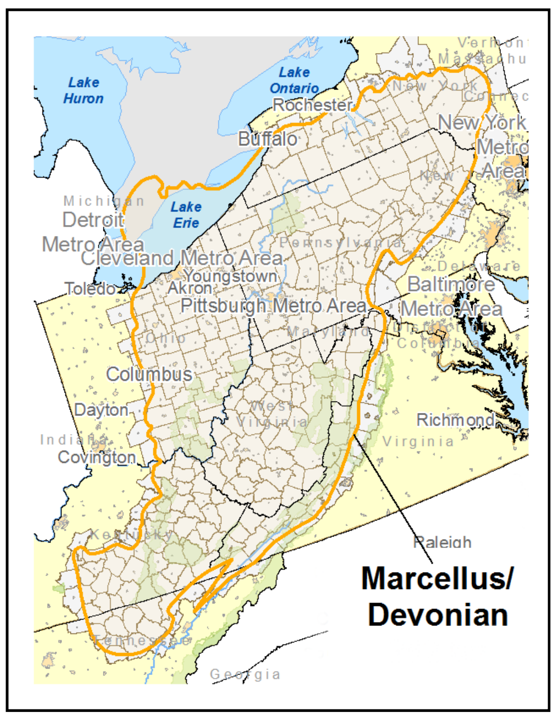
At an average well spacing in the Marcellus is 40 to 160 acres per well (Exhibit 11). The data in Exhibit 11 show technically recoverable resources for the formation to be 262 tcf, although much like the Haynesville, the play's potential estimates are frequently being revised upward due to its early stage of development.

EXHIBIT 18: STRATIGRAPHY OF THE MARCELLUS SHALE

Period		Group/Unit	
Penn		Pottsville	
Miss		Pocono	
Devonian	Upper	Conewango	
		Conneaut	
		Canadaway	
		West Falls	
		Sonyea	
		Genesee	
	Middle	Tully	
		Hamilton Group	Moscow
			Ludlowville
			Skaneateles
			Marcellus
		Onandaga	
	Lower	Tristates	
		Helderberg	

Source: Arthur et al, 2008[148]

EXHIBIT 19: MARCELLUS SHALE IN THE APPALACHIAN BASIN



Source: ALL Consulting, 2009

The Woodford Shale

Located in south-central Oklahoma, the Woodford Shale ranges in depth from 6,000 ft to 11,000 ft (Exhibit 21[149] and Exhibit 11). This formation is a Devonian-age shale bounded by limestone (Osage Lime) above and undifferentiated strata below (Exhibit 20).

Recent natural gas production in the Woodford Shale began in 2003 and 2004 with vertical well completions only[150]. However, horizontal drilling has been adopted in the Woodford, as in other shale gas plays, due to its success in the Barnett Shale[151].

The Woodford Shale play encompasses an area of nearly 11,000 square miles (Exhibit 11). The Woodford play is in an early stage of development and is occurring at a spacing interval of 640 acres per well (Exhibit 11). The average thickness of the Woodford Shale varies from 120 ft to 220 ft across the play (Exhibit 11).

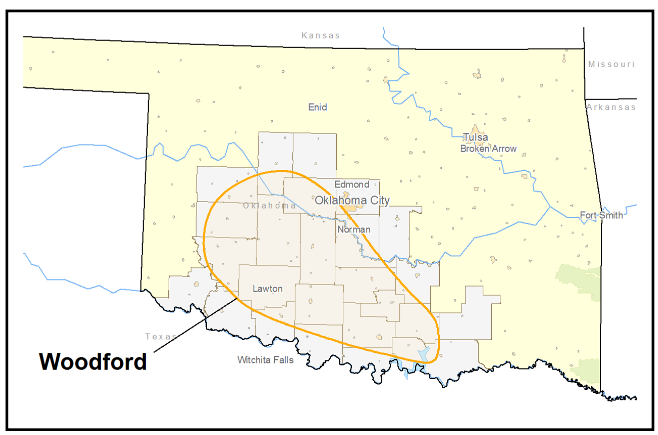
Gas content in the Woodford Shale is higher on average than some of the other shale gas plays at 200 scf/ton to 300 scf/ton (Exhibit 11). The original gas-in-place estimate for the Woodford Shale is similar to the Fayetteville Shale at 23 tcf while the technically recoverable resources are 11.4 tcf (Exhibit 11).

EXHIBIT 20: STRATIGRAPHY OF THE WOODFORD SHALE

Period		Group/Unit	
Permian	Ochoan	Cloyd Chief Fm	
	Guadalupian		
		White Horse Grp	
		El Reno Grp	
	Leonardian	Enid Grp	
	Wolfcampian	Chase Grp	
		Council Grove Grp	
		Admire Grp	
Penn.	Atokan	Atoka Grp	
	Morrowan	Morrow Grp	
Mississippian	Chesterian	Chester Grp	
	Meramecian	Miss Lime	Meramec Lime
	Osagean		Osage Lime
	Kinderhookian		
Devonian		Woodford Shale	
	Upper		
	Middle	Undifferentiated	
	Lower		
		Hunton Grp	Haragan Fm Henryhouse Fm

Source: Cardott, 2007[152]
AAPG, 1983[153]

EXHIBIT 21: WOODFORD SHALE IN THE ANADARKO BASIN



Source: ALL Consulting, 2009

The Antrim Shale

The Antrim Shale is located in the upper portion of the lower peninsula of Michigan within the Michigan Basin (Exhibit 23[154]). This Late Devonian-age shale is bounded by shale (Bedford Shale) above and by limestone (Squaw Bay Limestone) below and occurs at depths of 600 ft to 2,200 ft which is more typical of CBNG formations than most gas shales (Exhibit 22 and Exhibit 11).

Aside from the Barnett, the Antrim Shale has been one of the most actively developed shale gas plays with its major expansion taking place in the late 1980s[155].

The Antrim Shale encompasses an area of approximately 12,000 square miles and is characterized by distinct differences from other gas shales: shallow depth, small stratigraphic thickness with average net pay of 70 ft to 120 ft, and greater volumes of produced water in the range of 5 to 500 bbls/day/well[156] (Exhibit 11).

The gas content of the Antrim Shale ranges between 40 scf/ton and 100 scf/ton (Exhibit 11). The original gas-in-place for the Antrim is estimated at 76 tcf with technically recoverable resources estimated at 20 tcf (Exhibit 11). Well spacing ranges from 40 acres to 160 acres per well.

EXHIBIT 22: STRATIGRAPHY OF THE ANTRIM SHALE

Period		Group/Unit	
Quaternary	Pleistocene	Glacial Drift	
Jurassic	Middle	Ionia Formation	
Pennsylvanian	Late	Grand River Formation	
	Early	Saginaw Formation	
		Parma Formation	
Mississippian	Late		
		Bayport Limestone	
		Michigan Formation	
	Early	Marshall Sandstone	
		Coldwater Shale	
		Sunbury Shale	
Devonian	Late	Ellsworth Shale	Berea Sandstone
			Bedford Shale
		Upper Member	Antrim Shale
		Lachine Member	
		Paxton Member	
		Norwood Member	
		Squaw Bay Limestone	

Source: Catacosinos, et al., 2000 [157]

EXHIBIT 23: ANTRIM SHALE IN THE MICHIGAN BASIN

Source: ALL Consulting, 2009

EXHIBIT 24: STRATIGRAPHY OF THE NEW ALBANY SHALE

Period		Formation	
Pennsylvanian	Missourian	Mattoon	
Pennsylvanian	Missourian	Bond	
Pennsylvanian	Missourian	Patoka	
Pennsylvanian	Desmoinesian	Shelburn	
Pennsylvanian	Desmoinesian	Dugger	
Pennsylvanian	Desmoinesian	Petersburg	
Pennsylvanian	Desmoinesian	Linton	
Pennsylvanian	Desmoinesian	Staunton	
Pennsylvanian	Atokan	Brazil	
Pennsylvanian	Morrowan	Mansfield	
Mississippian	Chesterian	Tobinsport	
Mississippian	Chesterian	Branchville	
Mississippian	Chesterian	Tar Springs	
Mississippian	Chesterian	Glen Dean Limestone	
Mississippian	Chesterian	Hardinsburg	
Mississippian	Chesterian	Haney Limestone	
Mississippian	Chesterian	Big Clifty	
Mississippian	Chesterian	Beech Creek Limestone	
Mississippian	Chesterian	Cypress	Elwren
Mississippian	Chesterian	Reelsville Limestone	
Mississippian	Chesterian	Sample	
Mississippian	Chesterian	Beaver Bend Limestone	
Mississippian	Chesterian	Bethel	
Mississippian	Chesterian	Paoli Limestone	
Mississippian	Chesterian	Ste. Genevieve Ls.	
Mississippian	Valmeyeran	St. Louis Limestone	
Mississippian	Valmeyeran	Salem Limestone	
Mississippian	Valmeyeran	Harrodsburg Limestone	
Mississippian	Valmeyeran	Muldraugh	Ramp Creek
Mississippian	Valmeyeran	Edwardsville	
Mississippian	Valmeyeran	Spickert Knob	
Mississippian	Valmeyeran	New Providence Sh.	
Mississippian	Kinderhookian	Rockford Ls	Coldwater Sh.
Mississippian	Kinderhookian	New Albany Shale	Sunbury Sh.
Mississippian / Devonian	Kinderhookian / Senecan Chautauquan	New Albany Shale	Ellsworth Sh.
Devonian	Senecan Chautauquan / Erian	New Albany Shale	Antrim Sh.
Devonian	Erian	North Vernon Ls.	Transverse
Devonian	Erian	Jeffersonville Ls.	Detroit River

Source: Indiana Geological Survey, 1986[158]

The New Albany Shale

The New Albany Shale is located in the Illinois Basin in portions of southeastern Illinois, southwestern Indiana, and northwestern Kentucky[159] (Exhibit 25[160]). Similar to the Antrim Shale, the New Albany occurs at depths between 500 ft and 2,000 ft (Exhibit 11) and is a shallower, water-filled shale with a more CBNG-like character than the other gas shales discussed in this section. The New Albany formation is a Devonian- to Mississippian-age shale bounded by limestone above (Rockford Limestone) and below (North Vernon Limestone) (Exhibit 24).

The New Albany Shale is one of the largest shale gas plays, encompassing an area of approximately 43,500 square miles with approximately 80-acre spacing between wells (Exhibit 11). Similar to the Antrim Shale, the New Albany play has a thinner average net pay thickness of 50 ft to 100 ft and has wells which average 5 to 500 bbls of water per day[161] (Exhibit 11). The measured gas content of the New Albany Shale ranges from 40 scf/ton to 80 scf/ton. The original gas-in-place for the New Albany formation is estimated at 160 tcf with technically recoverable resources estimated at less than 20 tcf (Exhibit 11).

EXHIBIT 25: NEW ALBANY SHALE IN THE ILLINOIS BASIN

Source: ALL Consulting, 2009

REGULATORY FRAMEWORK

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency (EPA) administers most of the federal laws, although development on federally owned land is managed primarily by the Bureau of Land Management (BLM), which is part of the Department of the Interior, and the U.S. Forest Service, which is part of the Department of Agriculture. In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies. Those laws and their delegation are discussed below.

Federal Environmental Laws Governing Shale Gas Development

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act (CWA) regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act (SDWA) regulates the underground injection of fluids from shale gas activities. The Clean Air Act (CAA) limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts.

However, federal agencies do not have the resources to administer all of these environmental programs for all the oil and gas sites around the country. Also, as explained below, one set of nation-wide regulations may not always be the most effective way of assuring the desired level of environmental protection. Therefore, most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight). By statute, states may adopt their own standards; however, these must be at least as protective as the federal standards they replace, and may even be more protective in order to address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

By statute, states may adopt their own standards; however, these must be at least as protective as the federal standards they replace, and may even be more protective in order to address local conditions.

State Regulation

State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-size-fits-all regulation at the federal level[162]. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. The state agencies that permit these practices and monitor and enforce their laws and regulations may be located in the state Department of Natural Resources (such as in Ohio) or in the Department of Environmental Protection (such as in Pennsylvania). The Texas Railroad Commission regulates oil and gas activity in the nation's largest oil and gas producing state, home to the Barnett Shale. The names and organizational structures vary, but the functions are very similar. Often, multiple agencies are involved, having jurisdiction over different activities and aspects of development.

These state agencies do not only implement and enforce federal laws; they also have their own sets of state laws to administer. These state laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

The states have broad powers to regulate, permit, and enforce all activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well.

States have many tools at their disposal to assure that shale gas operations do not adversely impact the environment. The regulation of shale gas drilling and production is a cradle-to-grave approach. The states have broad powers to regulate, permit, and enforce all activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. Different states take different approaches to this regulation and enforcement, but state laws generally give the state oil and gas director or agency the discretion to require whatever is necessary to protect human health and the environment[a]. In addition to the general protection regulations, most states have a general prohibition against pollution from oil and gas drilling and production[b]. Most of the state requirements are written into rules or regulations, while some are added to permits on a case-by-case basis as a result of environmental review, on-the-ground inspections, public comments, or commission hearings.

All states require a permit before an operator can drill and operate a gas well. The application for this permit includes all the information about a well's location, construction, operation and reclamation. Agency staff reviews the application for compliance with regulations and to assure adequate environmental safeguards. If necessary, a site inspection will be made before permit approval. Also, most states require operators to post a bond or other financial security when getting a drilling permit to ensure compliance with state regulations and to make sure that there are funds to properly plug the well once production ceases. Another safeguard is that producers

[a] An example of this type of provision is the following from Pennsylvania's statute: "[T]he department shall have the authority to issue such orders as are necessary to aid in the enforcement of the provisions of [the oil and gas] act." (58 P.S. section 601.503.).

[b] An example of such language can be found in New York's rules, which state: "The drilling, casing and completion program adopted for any well shall be such as to prevent pollution. Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited." (6 NYCRR Part 554). Another example is the requirement in the rules of the Texas Railroad Commission: "No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state." (TAC 16.1.3.8).

generally must notify the state agencies of any significant new activity through a "sundry notice" or a new permit application so that the agency is aware of that activity and can review it[c].

States have implemented voluntary review processes to help ensure that the state programs are as effective as possible. The Ground Water Protection Council (GWPC) has a program to review state implementation of the Underground Injection Control (UIC) program. In addition to the GWPC UIC review, state oil and gas environmental programs other than UIC programs can also be periodically reviewed against a set of guidelines developed by an independent body of state, industry, and environmental stakeholders, known as STRONGER (State Review of Oil and Natural Gas Environmental Regulation, Inc.)[163]. Periodic evaluations of state exploration and production waste management programs have proven useful in improving the effectiveness of those programs and increasing cooperation between federal and state regulatory agencies. To date, 18 states have been reviewed under the state review guidelines, and several have been reviewed more than once. The STRONGER program has documented the effectiveness of and improvements in these state oil and gas environmental programs[164,165]. The Interstate Oil and Gas Compact Commission (IOGCC) also completed state reviews using earlier versions of the guidelines prior to the formation of STRONGER.

The organization of regulatory agencies within the various oil and gas producing states varies considerably. Some states have several agencies that may oversee some facet of oil and gas operations, especially environmental requirements. These agencies may be in various departments or divisions within the states' organizations. These various approaches have developed over time within each state, and each state tries to create a structure that best serves its citizenry and all of the industries that it must oversee. The one constant is that each oil and gas producing state has one agency with primary responsibility for permitting wells and overseeing general operations. While this agency may work with other agencies in the regulatory process, they can serve as a good source of information about the various agencies that may have jurisdiction over oil and gas activities. Exhibit 26 provides a list of the agencies with primary responsibility for oil and gas regulation in each of the states that have or are likely to have shale gas production.

Local Regulation

In addition to state and federal requirements, additional requirements regarding oil and gas operations may be imposed by other levels of government in specific locations. Entities such as cities, counties, tribes, and regional water authorities may each set operational requirements that affect the location and operation of wells or require permits and approvals in addition to those at the federal or state level.

[c] See, for example, Louisiana Statewide Order 29-B, section 105, or Texas Administrative Code 16.1.3.5.

EXHIBIT 26: OIL AND GAS REGULATORY AGENCIES IN SHALE GAS STATES

State	Agency	Web Address
Alabama	Geological Survey of Alabama, State Oil and Gas Board	http://www.ogb.state.al.us/ogb/ogb.html
Arkansas	Arkansas Oil and Gas Commission	http://www.aogc.state.ar.us/
Colorado	Colorado Department of Natural Resources, Oil and Gas Conservation Commission	http://cogcc.state.co.us/
Illinois	Illinois Department of Natural Resources, Division of Oil and Gas	http://dnr.state.il.us/mines/dog/index.htm
Indiana	Indiana Department of Natural Resources, Division of Oil and Gas	http://www.in.gov/dnr/dnroil/
Kentucky	Kentucky Department for Energy Development and Independence, Division of Oil and Gas Conservation	http://www.dogc.ky.gov/
Louisiana	Louisiana Department of Natural Resources, Office of Conservation	http://dnr.louisiana.gov/cons/conserv.ssi
Michigan	Michigan Department of Environmental Quality, Office of Geological Survey	http://www.michigan.gov/deq/0,1607,7-135-3306_28607---,00.html
Mississippi	Mississippi State Oil and Gas Board	http://www.ogb.state.ms.us/
Montana	Montana Department of Natural Resources and Conservation, Board of Oil and Gas	http://bogc.dnrc.mt.gov/default.asp
New Mexico	New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division	http://www.emnrd.state.nm.us/OCD/
New York	New York Department of Environmental Conservation, Division of Mineral Resources	http://www.dec.ny.gov/energy/205.html
North Dakota	North Dakota Industrial Commission, Department of Mineral Resources Oil and Gas Division	https://www.dmr.nd.gov/oilgas/
Ohio	Ohio Department of Natural Resources, Division of Mineral Resources Management	http://www.ohiodnr.com/mineral/default/tabid/10352/Default.aspx
Oklahoma	Oklahoma Corporation Commission, Oil and Gas Conservation Division	http://www.occ.state.ok.us/Divisions/OG/newweb/og.htm
Pennsylvania	Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management	http://www.dep.state.pa.us/dep/DEPUTATE/MINRES/OILGAS/oilgas.htm
Tennessee	Tennessee Department of Environment and Conservation, State Oil and Gas Board	http://www.tennessee.gov/environment/boards/oilandgas.shtml
Texas	The Railroad Commission of Texas	http://www.rrc.state.tx.us/index.html
West Virginia	West Virginia Department of Environmental Protection, Office of Oil and Gas	http://www.wvdep.org/item.cfm?ssid=23

When operations occur in or near populated areas, local governments may establish ordinances to protect the environment and the general welfare of its citizens. These local ordinances frequently require additional permits for issues such as well placement in flood zones, noise level, set backs from residences or other protected sites, site house-keeping, and traffic. For example, ordinances may set limits on noise levels that may be generated during both daytime and nighttime operations[166,167,168,169].

In some cases, regional water-permitting authorities that have jurisdiction in multiple states have also been established. These federally established authorities have been created to protect the water quality of the entire river basin and to govern uses of the water[170]. Additional approvals and permits may be required for operations in these river basins. For example, the Delaware River Basin Commission (DRBC) covers parts of New York, Pennsylvania, New Jersey and Delaware[171]. Natural gas operators wishing to withdraw water for consumptive use in this basin must first receive a permit from the DRBC, which has the legal authority to fine violators of their rules and regulations.

The variety of laws governing shale gas exploration and production, and the multitude of federal and state agencies that implement them, can sometimes be confusing. Therefore, the following discussion has been organized according to the various environmental media that are affected by these activities, i.e., water, air, and land. The major laws and programs affecting each of these are discussed below. Additional considerations on federal land and unique state requirements are also covered, along with some of the programs that cut across these environmental media.

Regulation of Impacts on Water Quality

Potential impacts to water quality are primarily regulated under several federal statutes and the accompanying state programs. The primary federal statutes governing water quality issues related to shale gas development are the Clean Water Act, the Safe Drinking Water Act, and the Oil Pollution Act. These statutes and their relationships to shale gas development are discussed below.

Clean Water Act

The Clean Water Act (CWA) is the primary federal law in the U.S. governing pollution of surface water. It was established to protect water quality, and includes regulation of pollutant limits on the discharge of oil- and gas-related produced water. This is conducted through the National Pollutant Discharge Elimination System (NPDES) permitting process. Although EPA sets national standards at the federal level, states and tribal governments can acquire primacy for the NPDES program by meeting EPA's primacy requirements.

The CWA establishes the basic structure for regulating discharges of pollutants into the waters of the U.S. and quality standards for surface waters. The basis of the CWA was enacted in 1948 and was called the Federal Water Pollution Control Act; the Act was significantly reorganized and expanded in 1972. "Clean Water Act" became its common name, with additional amendments made in 1977 and later.

Under the CWA, EPA has implemented pollution control programs such as setting wastewater standards for industry. They have also set water quality standards for a variety of contaminants in surface waters.

The CWA made it unlawful to discharge any pollutant from a point source into the navigable waters of the U.S., unless done in accordance with a specific approved permit. The NPDES permit program controls discharges from point sources that are discrete conveyances, such as pipes or man-made ditches. Industrial, municipal, and other facilities such as shale gas production sites or commercial facilities that handle the disposal or treatment of shale gas produced water must obtain permits if they intend to discharge directly into surface waters[172,173]. Large facilities usually have individual NPDES permits. Discharges from some smaller facilities may be eligible for inclusion under general permits that authorize a category of discharges under the CWA within a geographical area. A general permit is not specifically tailored for an individual discharger. Most oil and gas production facilities with related discharges are authorized under general permits because there are typically numerous sites with common discharges in a geographic area.

A state that meets the federal primacy requirements is allowed to set more stringent state-specific standards for this program. Since individual states can acquire primacy over their respective programs, it is not uncommon to have varying requirements from state to state. This variation can affect how the oil and gas industry manages produced water within a drainage basin located within two or more states, such as the Marcellus shale in the Appalachian Basin. Effluent limitations serve as the primary mechanism under NPDES permits for controlling discharges of pollutants to receiving waters. When developing effluent limitations for an NPDES permit, a permit writer must consider limits based on both the technology available to control the pollutants (i.e., technology-based effluent standards) and the regulations that protect the water quality standards of the receiving water (i.e., water quality-based effluent standards).

The intent of technology-based effluent limits in NPDES permits is to require treatment of effluent concentrations to less than a maximum allowable standard for point source discharges to the specific surface water body. This is based on available treatment technologies, while allowing the discharger to use any available control technique to meet the limits. For industrial (and other non-municipal) facilities, technology-based effluent limits are derived by: 1) using national effluent limitations guidelines and standards established by EPA, or 2) using best professional judgment (BPJ) on a case-by-case basis in the absence of national guidelines and standards.

Prior to the granting of a permit, the authorizing agency must consider the potential impact of every proposed surface water discharge on the quality of the receiving water, not just individual discharges. If the authorizing agency determines that technology-based effluent limits are not sufficient to ensure that water quality standards will be attained in the receiving water, the CWA [Section 303(b)(1)(c)] and NPDES regulations [40 Code of Federal Regulations (CFR) 122.44(d)] require that more stringent limits are imposed as part of the permit[174].

EPA establishes effluent limitation guidelines (ELGs) and standards for different non-municipal (i.e., industrial) categories. These guidelines are developed based on the degree of pollutant reduction attainable by an industrial category through the application of pollution control technologies.

The CWA requires EPA to develop specific effluent guidelines that represent the following:

1. Best conventional technology (BCT) for control of conventional pollutants and applicable to existing dischargers.
2. Best practicable technology (BPT) currently available for control of conventional, toxic and nonconventional pollutants and applicable to existing dischargers.
3. Best available technology (BAT) economically achievable for control of toxic and nonconventional pollutants and applicable to existing dischargers.
4. New source performance standards (NSPS) for conventional pollutants and applicable to new sources.

To date, EPA has established guidelines and standards for more than 50 different industrial categories[175].

The ELGs for Oil and Gas Extraction, which were published in 1979, can be found at 40 CFR Part 435. The onshore subcategory, Subpart C, is applicable to discharges associated with shale gas development and production[176].

The CWA also includes a program to control storm water discharges. The 1987 Water Quality Act (WQA) added Section 402(p) to the CWA requiring EPA to develop and implement a storm water permitting program. EPA developed this program in two phases (Phase I: 1990; Phase II: 1999). Those regulations establish NPDES permit requirements for municipal, industrial, and construction site storm water runoff. The WQA also added Section 402(l)(2) to the CWA specifying that the EPA and states shall not require NPDES permits for uncontaminated storm water discharges from oil and gas exploration, production, processing or treatment operations, or transmission facilities. This exemption applies where the runoff is not contaminated by contact with raw materials or wastes. EPA had previously interpreted the 402(l)(2) exemption as not applying to construction activities of oil and gas development, such as building roads and pads (i.e., an NPDES permit was required)[177].

The Energy Policy Act of 2005 modified the CWA Section 402(l)(2) exemption by defining the excluded oil and gas sector operations to include all oil and gas field activities and operations, including those necessary to prepare a site for drilling and for the movement and placement of drilling equipment. EPA promulgated a rule that implemented this exemption. However, on May 23, 2008, the U.S. Court of Appeals for the Ninth Circuit released a decision vacating the permitting exemption for discharges of sediment from oil and gas construction activities that contribute to violations of the CWA[178]. The court based its decision on the fact that the new rule exempted runoff contaminated with sediment, while the CWA does not exempt such runoff. As a result of the court's decision, storm water discharges contaminated with sediment resulting in a water quality violation require permit coverage under the NPDES storm water permitting program.

While the EPA storm water permitting rule contains a broad exclusion for oil and gas sector construction activities, it is important to note that individual states and Indian tribes may still regulate storm water associated with these activities. EPA has clarified its position that states and tribes may not regulate such storm water discharges under their CWA authority, but are free to regulate under their own independent authorities. EPA states that "[t]his final rule is not intended to interfere with the ability of states, tribes, or local governments to regulate any discharges through a non-NPDES permit program"[179]. In addition to state and tribal regulation, the industry has a voluntary program of Reasonable and Prudent Practices for Stabilization (RAPPS) of oil and gas construction sites[180]. Producers use RAPPS in order to control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading, and excavating activities related to site preparation.

Safe Drinking Water Act

Congress originally passed the Safe Drinking Water Act (SDWA) in 1974 to protect public health by regulating the nation's public drinking water supply. The law was amended in 1986 and 1996 and requires many actions to protect drinking water and its sources, including rivers, lakes, reservoirs, springs, and ground water wells. SDWA authorizes the U.S. EPA to set national health-based standards for drinking water to protect against both naturally occurring and man-made contaminants that may be found in drinking water. EPA, states, and municipal water system agencies then work together to make sure that these standards are met[181].

As one aspect of the protection of drinking water supplies, the SDWA establishes a framework for the Underground Injection Control (UIC) program to prevent the injection of liquid wastes into underground sources of drinking water (USDWs). The EPA and states implement the UIC program, which sets standards for safe waste injection practices and bans certain types of injection altogether. The UIC Program provides these safeguards so that injection wells do not endanger USDWs. The first federal UIC regulations were issued in 1980.

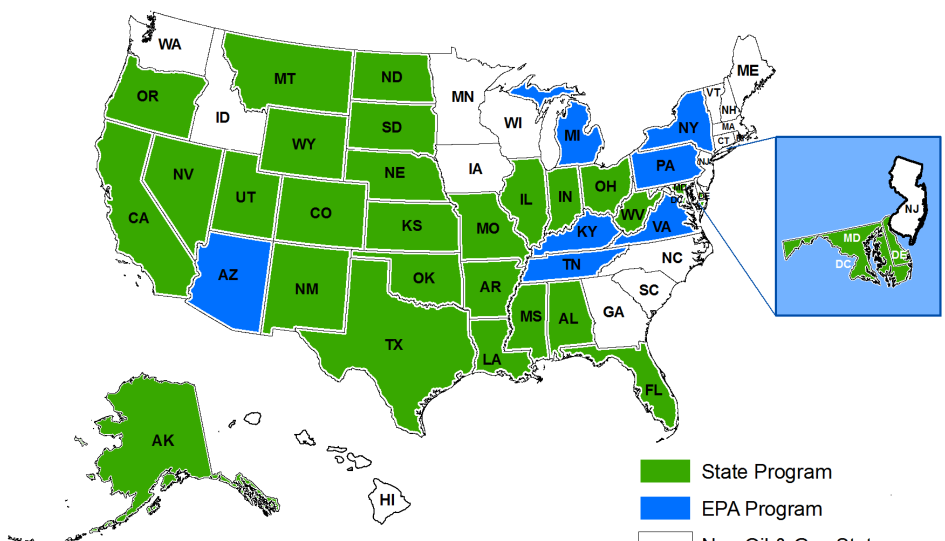
EPA currently groups underground injection wells into five classes for regulatory control purposes, and has a sixth class under consideration. Each class includes wells with similar functions, construction and operating features so that technical requirements can be applied consistently to the class.

1. **Class I** wells may inject hazardous and nonhazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost USDW. Because they may inject hazardous waste, Class I wells are the most strictly regulated and are further regulated under the Resource Conservation and Recovery Act (RCRA).
2. **Class II** wells may inject brines and other fluids associated with oil and gas production.
3. **Class III** wells may inject fluids associated with solution mining of minerals.
4. **Class IV** wells may inject hazardous or radioactive wastes into or above a USDW and are banned unless specifically authorized under other statutes for ground water remediation.
5. **Class V** includes all underground injection not included in Classes I-IV. Generally, most Class V wells inject nonhazardous fluids into or above a USDW and are on-site disposal systems, such as floor and sink drains which discharge to dry wells, septic systems, leach fields, and drainage wells. Injection practices or wells that are not covered by the UIC Program include single family septic systems and cesspools as well as non-residential septic systems and cesspools serving fewer than 20 persons that inject ONLY sanitary waste water.
6. **Class VI** has been proposed specifically for the injection of CO_2 for the purpose of sequestration, but has not yet been established.

Most injection wells associated with oil and gas production are Class II wells. These wells may be used to inject water and other fluids (e.g., liquid CO_2) into oil- and gas-bearing zones to enhance recovery, or they may be used to dispose of produced water. The regulation specifically prevents the disposal of waste fluids into USDWs by limiting injection only to formations that are not "underground sources of drinking water." EPA's UIC Program is designed to prevent contamination of water supplies by setting minimum requirements for state UIC Programs. The basic premise of the UIC Program is to prevent contamination of USDWs by keeping injected fluids within the intended injection zone. The injected fluids must not endanger, or have the potential to endanger, a current or future public water supply. The UIC requirements that affect the siting, construction, operation, maintenance, monitoring, testing, and, finally, closure of injection wells have been established to address these concepts. All injection wells require authorization under general rules or specific permits.

The law was written with the understanding that states are best suited to have primary enforcement authority (primacy) for the UIC Program. In the SDWA, Congress cautioned EPA against a "one-size-fits-all" regulatory scheme, and mandated consideration of local conditions and practices. Section 1421(b)(3)(A) requires that UIC regulations permit or provide consideration of varying geological, hydrological, or historical conditions in different states and in different areas within a state. Section 1425 allows a state to obtain primacy from EPA for oil- and gas-related injection wells, without being required to adopt the complete set of applicable federal UIC regulations. The state must be able to demonstrate that its existing regulatory program is protecting USDWs as effectively as the federal requirements[182].

EXHIBIT 27: UIC CLASS II PRIMACY MAP



Source: EPA,, 2008

To date, 40 states have obtained primacy for oil and gas injection wells (Class II), although, as shown in Exhibit 27 not all of these states have oil and gas production. The U.S. EPA administers UIC programs for ten states, seven of which are oil and gas states, and all other federal jurisdictions and Indian Lands[183] (Exhibit 27[184]).

Oil Pollution Act of 1990 – Spill Prevention Control and Countermeasure

The CWA and the Oil Pollution Act (OPA) include both regulatory and liability provisions that are designed to reduce damage to natural resources from oil spills. Congress added Section 311 to the

CWA, which in part authorized the President to issue regulations establishing procedures, methods, equipment, and other requirements to prevent discharges of oil from vessels and facilities [Section 311(j)(1)(c)]. In response to the Exxon Valdez oil spill in Alaska, Congress enacted the OPA in 1990[185]. The OPA amended CWA Section 311 and contains provisions applicable to onshore facilities and operations.

Section 311, as amended by the OPA, provides for spill prevention requirements, spill reporting obligations, and spill response planning. It regulates the prevention of and response to accidental releases of oil and hazardous substances into navigable waters, on adjoining shorelines, or affecting natural resources belonging to or managed by the U.S. This authority is primarily carried out through the creation and implementation of facility and response plans. These plans are intended to establish measures that will prevent discharge of oil into navigable waters of the U.S. or adjoining shore-lines as opposed to response and cleanup after a spill occurs.

A cornerstone of the strategy to prevent oil spills from reaching the nation's waters is the oil Spill Prevention, Control and Countermeasure (SPCC) plan. EPA promulgated regulations to implement this part of the OPA of 1990. These regulations specify that:

1. SPCC Plans must be prepared, certified (by a professional engineer) and implemented by facilities that store, process, transfer, distribute, use, drill for, produce, or refine oil;
2. Facilities must establish procedures and methods and install proper equipment to prevent an oil release;
3. Facilities must train personnel to properly respond to an oil spill by conducting drills and training sessions; and,
4. Facilities must also have a plan that outlines steps to contain, clean up and mitigate any effects that an oil spill may have on waterways[186].

Before a facility is subject to the SPCC rule, it must meet three criteria:

1. It must be non-transportation-related;
2. It must have an aggregate aboveground storage capacity greater than 1,320 gallons (31.4 bbls) or a completely buried storage capacity greater than 42,000 gallons (1,000 bbls); and
3. There must be a reasonable expectation of a discharge into or upon navigable waters of the U.S. or adjoining shorelines.

An SPCC Plan is a site-specific document that describes the measures the facility owner has taken to prevent oil spills, and what measures are in place, if needed, to contain and clean spills. It includes information about the facility, the oil storage containment, inspections, and a site diagram with locations of tanks (above and below ground) and drainage, and other pertinent details. Prevention measures include secondary containment around tanks and certain oil-containing equipment.

The SPCC program is not as applicable to shale gas operations as it is to oil production sites. Shale gas operators may have to prepare plans if they store large amounts of fuel (exceeding the volumes stated above) on site, or if oil-filled equipment is present, and there is a risk of that oil impacting waters of the U.S.

In October 2007, EPA proposed amendments to the SPCC rule intended to increase clarity and tailor certain requirements to ensure increased compliance. Among other things, these amendments would streamline some requirements by allowing the use of a plan template for smaller facilities, extending some deadlines for plan preparation, and exempting some vessels and flow lines from secondary containment requirements. They would also add spill prevention requirements for some oil and gas facilities. These proposed rules have not yet been made final[187].

State Regulations and Regional Cooperation

In addition to implementing federal statutes for the NPDES, UIC, and storm water programs, states and tribes may impose their own requirements to protect their water resources, both surface and underground. For example, they establish water quality standards for some or all of their surface water. These standards are approved by EPA and become the baseline for CWA permits[188].

In addition, some areas have established regional water authorities that regulate water withdrawals and discharges within a river basin. For example, the Susquehanna River Basin Commission (SRBC)[189] and the DRBC[190] in New York and Pennsylvania require that entities seeking to withdraw water from their river systems first obtain permits. These commissions have authority separate from the states. They have recently directed their attention to the water requirements for drilling and hydraulically fracturing Marcellus Shale gas wells and are updating their requirements for both water withdrawals and discharge of the water after use. Other river basin commissions are more advisory in nature, providing water flow and quality information and coordinating river conservation efforts by state agencies and others.

State agencies are the principal organizations for enforcing water quality regulations. They have inspectors, usually located at regional offices throughout the state, who visit oil and gas well sites to ensure compliance with regulations. When a violation occurs, state enforcement and legal personnel develop the case and order compliance, in many cases also imposing penalties against the violator. Penalties can range from fines to revocation of permits, and even to criminal sanctions in severe cases. Such penalties are usually imposed only after hearings before a board of commissioners or other state body. In addition to fines and penalties, companies that pollute surface or ground water must clean up or remediate the contamination they caused.

Regulation of Impacts on Air Quality

Air quality impacts are regulated under the Clean Air Act (CAA). As described below, the Act sets national standards for emissions of certain pollutants and requires permits for some industrial operations. Greenhouse Gases are not regulated as such, and are not, therefore, discussed in this section.

Clean Air Act

The CAA is the primary means by which EPA regulates potential emissions that could affect air quality. The U.S. Congress passed the CAA in 1963, and they have amended it on several occasions since, most recently in 1990[191]. The CAA requires EPA to set national standards to limit levels of certain pollutants. EPA regulates those pollutants by developing human health-based and/or environmentally and scientifically based criteria for setting permissible levels. Air regulations do not normally include exceptions for a company's size, the age of a field, or the type of operation. Typically, the air rules are silent on issues such as conventional versus unconventional plays, old versus new fields, and the depth of a well. For the most part, the air emissions, applicable regulations, and associated emissions controls for a shale play are no different than those for any other natural gas operation. There may be differences due to location (some areas of the country have better air quality than others), equipment needs (some shale plays may produce a wetter gas than others), and sulfur content level of the gas.

Geographic areas that do not meet EPA's standards for a given pollutant are designated as "nonattainment areas"[192]. This is the case for the Barnett Shale play, much of which is located in or near the Dallas-Fort Worth ozone nonattainment area. As a result, Barnett Shale production activities must often comply with much more stringent regulations than similar operations proposed outside of a nonattainment area. As a result of the implementation of the CAA, air quality has improved dramatically across the U.S. during the last few decades and existing regulations should continue to reduce air pollution emissions during the next twenty years or longer[193].

Air Quality Regulations

Like any other U.S. industry, shale gas producers must comply with existing and new air regulations including those resulting from the 1990 CAA Amendments. These rules pose an ongoing challenge to company resources as producers strive to understand and comply with enforcement, fines, public reaction, and possibly even project cancellations in light of new standards.

EPA has established National Emission Standards for Hazardous Air Pollutants (NESHAPs), which are nationally uniform standards to control specific air emissions. In 2007, EPA implemented a new standard referred to as the Maximum Achievable Control Technology (MACT) standard for hazardous air pollutants (HAP) that targeted small area sources such as shale gas operations located in areas near larger populations. These standards limit HAP emissions (primarily benzene) from process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks.

Another example of new or amended federal regulations that will have a direct impact on controlling emissions from shale gas operations is the Stationary Spark Ignition Internal Combustion Engine new source performance standard[194] and Reciprocating Internal Combustion Engine NESHAP[195] rules, which regulate new and refurbished engines. These rules, passed in 2007, target all internal combustion engines regardless of horsepower rating, location, or fuel (electric engines are not included) and include extensive maintenance, testing, monitoring, recordkeeping, and reporting requirements[196].

EPA is not large enough to regulate every air emissions source nationwide, let alone consider the local and regional differences. Therefore, they typically delegate that role to local, state, and tribal agencies. This delegation of authority can include rule implementation, permitting, reporting, and compliance. Any state given such delegation of authority can pass more restrictive rules, but they are prohibited from passing a rule that is less stringent than its federal counterpart.

Air Permits

Air permits are legal documents that facility owners and operators must abide by. The permit specifies what construction is allowed, what emission limits must be met, how the emissions source(s) must be operated, and what conditions—specifying monitoring, record keeping, and reporting requirements—must be maintained to assure ongoing compliance. Shale gas producers may need air quality permits for a number of emissions sources, including gas compressor engines, glycol dehydrators, and flares.

A company's permitting responsibility does not end with the issuance of their initial air permit. They must be constantly vigilant that a new regulation, modification, replacement, or process change does not impact their existing permit and require a permit amendment or a more stringent permit. Although these permits may differ across the country, they all contain specific conditions designed to ensure state and federal standards are met and to prevent any significant degradation in air quality as a result of a proposed activity.

Regulation of Impacts to Land

Impacts to land from shale gas operations include solid waste disposal and surface disturbances that may impact the visual landscape or may affect wildlife habitat. Operations on federal lands are a special case with unique requirements that are discussed below.

Resource Conservation and Recovery Act (RCRA)

RCRA was passed in 1976 to address the growing problems of the increasing volume of municipal and industrial waste. RCRA established goals for protecting human health and the environment, conserving resources, and reducing the amount of waste. RCRA Subtitle C established a federal program to manage hazardous wastes from cradle to grave to ensure that hazardous waste is handled in a manner that protects human health and the environment. Subtitle D of the RCRA addresses non-hazardous solid wastes, including certain hazardous wastes which are exempted from the Subtitle C regulations[197].

In 1978, EPA proposed hazardous waste management standards that included reduced requirements for some industries, including oil and gas, with large volumes of wastes. EPA determined that these large volume "special wastes" were lower in toxicity than other wastes being regulated as hazardous waste under the RCRA[198].

In 1980, the Solid Waste Disposal Act (SWDA) amended RCRA to exempt drilling fluids, produced waters, and other wastes associated with exploration, development, and production of crude oil, natural gas and geothermal energy[199]. The SWDA Amendments also required EPA to provide a report to Congress on these wastes and to make a regulatory determination as to whether regulation of these wastes under RCRA Subtitle C was warranted[200].

In 1988, EPA issued a final regulatory determination stating that control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted.

In 1987, EPA issued a Report to Congress that outlined the results of a study on the management, volume, and toxicity of wastes generated by the oil, natural gas and geothermal industries. In 1988, EPA issued a final regulatory determination stating that control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted. EPA made this determination because it found that other state and federal programs could protect human health and the environment more effectively. In lieu of regulation under Subtitle C, EPA implemented a three-pronged strategy to ensure that the environmental and programmatic issues were addressed:

1. Improve other federal programs under existing authorities;
2. Work with states to improve some programs; and
3. Work with Congress to develop any additional statutory authorities that may be required[201].

These wastes have remained exempt from Subtitle C regulations, but this does not preclude these wastes from control under state regulations or other federal regulations[202]. The exemption applies only to the federal requirements of RCRA Subtitle C. A waste that is exempt from Subtitle C regulation might be subject to more stringent or broader state hazardous and non-hazardous waste regulations and other state and federal program regulations. For example, oil and gas exploration and production wastes may be subject to regulation under RCRA Subtitle D, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, and/or the Oil Pollution Act of 1990[203,204].

In 1989, EPA worked with the Interstate Oil and Gas Compact Commission (IOGCC), state regulatory officials, industry representatives, and nationally recognized environmental groups to establish a Council on Regulatory Needs. The purpose of the council was to review existing state oil and gas exploration and production waste management programs and to develop guidelines to describe the elements necessary for an effective state program. This effort was begun by EPA as part of the second prong of the agency's approach. These groups then worked together with state regulatory agencies to review the state programs, on a voluntary basis, against these guidelines and to make recommendations for improvement. This state review program continues today under the guidance of a non-profit organization called STRONGER. The state programs reviewed to date represent over 90% of the onshore domestic production[205].

Working with the IOGCC, STRONGER has continued to update the guidelines consistent with developing environmental and oilfield technologies and practices. Under the state review process, state programs have continued to improve, and follow-up reviews have shown significant improvement where states have successfully implemented the recommendations of the review committees.

Endangered Species Act

The Endangered Species Act (ESA) of 1973 (Pub. L. 93-205) protects plants and animals that are listed by the federal government as "endangered" or "threatened"[206]. Sections 7 and 9 are central to regulating oil and gas activities. Section 9 makes it unlawful for anyone to "take" a listed animal, and this includes significantly modifying its habitat[207]. This applies to private parties and private land; a landowner is not allowed to harm an endangered animal or its habitat on his or her property.

Section 7 applies not to private parties, but to federal agencies. This section covers not only federal activities but also the issuance of federal permits for private activities, such as Section 404 permits issued by the Corps of Engineers, to people who want to do construction work in waters or wetlands[208]. Section 7 imposes an affirmative duty on federal agencies to ensure that their actions (including permitting) are not likely to jeopardize the continued existence of a listed species (plant or animal) or result in the destruction or modification of critical habitat. Both Sections 7 and 9 allow "incidental takes" of threatened or endangered species, but only with a permit.

To "take" is to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect a plant or animal of any threatened or endangered species. Harm includes significant habitat modification when it kills or injures a member of a listed species through impairment of essential behavior (e.g., nesting or reproduction).

For any non-federal industrial activity, the burden is on the owner and/or operator to determine if an incidental take permit is needed. This is typically accomplished by contacting the U.S. Fish and Wildlife Service (FWS) to determine whether any listed species are present or will potentially inhabit the project site. A biological survey may be required to determine whether protected species are present on the site and whether a Section 9 permit may be required[209,210]. The FWS as well as many state fish and game agencies offer services to help operators determine whether a given project is likely to result in a take and whether a permit is required. FWS can also provide technical assistance to help design a project so as to avoid impacts. For example, the project could be designed to minimize disturbances during nesting or mating seasons[211].

A Section 9 permit must include a habitat conservation plan (HCP) consisting of: an assessment of impacts; measures that will be undertaken to monitor, minimize and mitigate any impacts; alternative actions considered and an explanation of why they were not taken; and any additional measures that the FWS may require[212]. Mitigation measures, which are actions that reduce or address potential adverse effects of a proposed activity upon species, must be designed to address the specific needs of the species involved and be manageable and enforceable. Mitigation measures may take many forms, such as preservation (via acquisition or conservation easement) of existing habitat; enhancement or restoration of degraded or former habitat; creation of new habitats; establishment of buffer areas around existing habitats; modifications of land use practices; and restrictions on access[213].

State Endangered Species Protections

All fifty states have fish and game/wildlife agencies that work in cooperation with the U. S. FWS district offices with regard to the incidental take permitting process. Many states also have their own endangered and threatened species lists that may include species not on the federal lists, and have their own requirements for protecting endangered species[214].

Oil and Gas Operations on Public Lands

Federal Lands

The U.S. Department of Interior's Bureau of Land Management (BLM) is responsible for permitting and managing most onshore oil and gas activities on federal lands. The BLM carries out its responsibility to protect the environment throughout the process of oil and gas resource exploration and development on public lands. Resource protection is considered throughout the land use planning process—when Resource Management Plans (RMPs) are prepared and when an Application for Permit to Drill (APD) is processed[215]. The BLM's inspection and enforcement and monitoring program is designed to ensure that operators comply with relevant laws and regulations as well as specific stipulations set forth during the permitting process.

Since most shale gas activity in the near future is expected to occur in the eastern U.S. basins, it is not likely that much of this development will occur on federal lands. While there are some federal lands, such as National Parks, National Forests, and military installations, these are much less extensive in the east than in the west. Where shale gas operations do occur on federal lands, BLM has a well established program for managing these activities to protect human health and the environment.

State Lands

The amount of state-owned land varies considerably from state to state and each state manages these lands differently. In most states, leasing of state-owned minerals occurs through lease auctions. Since states are already set up to manage oil and gas operations within their borders, no special permitting or enforcement systems are required. Some states do have Environmental Policy Acts that require a review of environmental impacts that may result from leasing or operations on state lands or of any state action that may affect the environment.

Other Federal Laws and Requirements that Protect the Environment

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, was enacted by Congress on December 11, 1980. This law created a tax on the chemical and petroleum industries and provided broad federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment. CERCLA established prohibitions and requirements concerning closed and abandoned hazardous waste sites, provided for liability of persons responsible for releases of hazardous waste at these sites, and established a trust fund to provide for cleanup when no responsible party could be identified. Over five years, $1.6 billion was collected and placed in a trust fund for cleaning up abandoned or uncontrolled hazardous waste sites.

CERCLA was amended by the Superfund Amendments and Reauthorization Act (SARA) in 1986. SARA made several changes to the Superfund program that augmented its effectiveness, provided new enforcement authorities, boosted state and citizen involvement, and increased the size of the trust fund.

In addition to the provisions for cleaning up hazardous waste sites, CERCLA requires the person in charge of a vessel or facility to immediately notify the National Response Center when there is a release of a hazardous substance in an amount equal to or greater than the reportable quantity (RQ) for that substance [CERCLA Section 103(a)]. The reportable quantity depends on the substance released.

CERCLA Section 101(14) excludes certain substances from the definition of hazardous substance, thus exempting them from CERCLA regulation. These substances include petroleum, meaning crude oil or any fraction thereof that is not specifically listed as a hazardous substance, natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel. If a release of one of these substances occurs, CERCLA notification is not required. Thus, CERCLA reporting will only apply to shale gas production and processing sites if hazardous substances other than crude oil or natural gas are spilled in reportable quantities; such are not usually present at these sites.

However, this particular exclusion applies only to CERCLA Section 103(a) reporting requirements; it does not exempt a facility from the Emergency Planning and Community Right-to-Know Act (EPCRA) Section 304 reporting requirements. A release of a petroleum product containing certain substances is potentially reportable under EPCRA Section 304 if more than an RQ of that substance is released[216].

Many states have separate requirements regarding hazardous substances. Reporting of releases of the materials exempted under CERCLA may be required under state law.

Emergency Planning and Community Right-to-Know Act

Congress enacted EPCRA in 1986 to establish requirements for federal, state and local governments, tribes, and industry regarding emergency planning and "community right-to-know" reporting on hazardous and toxic chemicals. The community right-to-know provisions of EPCRA are the most relevant part of the law for shale gas producers. They help increase the public's knowledge and access to information on chemicals at individual facilities, along with their uses and potential releases into the environment.

Under Sections 311 and 312 of EPCRA, facilities manufacturing, processing, or storing designated hazardous chemicals must make Material Safety Data Sheets (MSDSs), describing the properties and health effects of these chemicals, available to state and local officials and local fire departments. Facilities must also provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDSs exist. Information about chemical inventories at facilities and MSDSs must be available to the public. Facilities that store over 10,000 pounds of hazardous chemicals are subject to this requirement. Any hazardous chemicals above the threshold stored at shale gas production and processing sites must be reported in this manner.

Section 313 of EPCRA authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and waste management activities reported annually by certain industries as well as federal facilities. EPA issues a list of industries that must report releases for the database. To date, EPA has not included oil and gas extraction as an industry that must report under TRI. This is not an exemption in the law. Rather it is a decision by EPA that this industry is not a high priority for reporting under TRI. Part of the rationale for this decision is based on the fact that most of the information required under TRI is already reported by producers to state agencies that make it publicly available. Also, TRI reporting from the hundreds of thousands of oil and gas sites would overwhelm the existing EPA reporting system and make it difficult to extract meaningful data from the massive amount of information submitted[217, 218].

EPCRA section 304 requires reporting of releases to the environment of certain materials that are subject to this law. As noted in the section above, this requirement would apply to any releases of petroleum products that exceed reporting thresholds, even if those products are exempt from CERCLA reporting. While shale gas production facilities do not normally store the materials subject to EPCRA reporting, known as EPCRA "Extremely Hazardous Substances" and CERCLA hazardous substances, a limited number of chemicals used in the hydraulic fracturing process, such as hydrochloric acid, are classified as hazardous under CERCLA. These chemicals may be brought on site for a few days, at most, during fracturing or work-over operations. Businesses must report non-permitted releases—into the atmosphere, surface water, or groundwater—of any listed chemical above threshold amounts, known as the "reportable quantity", to federal, state, and local authorities. Therefore, while every precaution is taken to prevent chemical spills, in the event of an accidental release above the reportable quantity, a report would be made to these authorities by the operator.

Occupational Safety and Health Act

Under the Occupational Safety and Health Act of 1970, employers are responsible for providing a safe and healthy workplace for their employees. The Occupational Safety and Health Administration (OSHA) promotes the safety and health of America's working men and women by setting and enforcing standards; providing training, outreach and education; establishing partnerships; and encouraging continual process improvement in workplace safety and health[219].

OSHA has developed specific standards to reduce potential safety and health hazards in the oil and gas drilling, servicing and storage industry[220]. States also have requirements that provide further worker and public safety protections.

Summary

The U.S. has a long history of actively regulating the oil and gas industry including the shale gas industry. A comprehensive set of federal and state laws and programs regulate all aspects of shale gas exploration and production activities. Under these programs, federal, state and local agencies enforce an array of requirements designed to protect human health and the environment during drilling, production, and abandonment operations. Together, these requirements have reduced environmental risk and adverse impacts to our water, air, and land nationwide.

A comprehensive set of federal and state laws and programs regulate all aspects of shale gas exploration and production activities.

ENVIRONMENTAL CONSIDERATIONS

As described in the previous sections, natural gas is an important part of the nation's energy supply. As a clean-burning, affordable and reliable source of energy, natural gas will continue to play a significant role in the energy supply picture for years to come. Unconventional sources of natural gas have become a major component of that future supply and shale gas is rapidly emerging as a critical part of that resource.

There exists an extensive framework of federal, state, and local requirements designed to manage virtually every aspect of the natural gas development process. These regulatory efforts are primarily led by state agencies and include such things as ensuring conservation of gas resources, prevention of waste, and protection of the rights of both surface and mineral owners while protecting the environment[221]. As part of their environmental protection mission, state agencies are responsible for safeguarding public and private water supplies, preserving air quality, addressing safety, and ensuring that wastes from drilling and production are properly contained and disposed of[222].

In order to make sound decisions about future shale gas development, it is important to understand the process of drilling and producing shale gas wells (Exhibit 28) and the attendant environmental considerations. A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective BMPs, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Many of the human and environmental considerations associated with shale gas production are common to all oil and gas development. However, the horizontal drilling and hydraulic fracturing that have become the standard for modern shale gas development bring with them new considerations as well as new ways to reduce impacts. As shale gas development has spread into more densely populated areas, new challenges have been encountered and new technologies and practices have been developed to meet these challenges. In addition, collaborations between industry, regulators and the public have created innovative environmental solutions to problems that at first seemed insurmountable.

Collaborations between industry, regulators and the public have created innovative environmental solutions to problems that at first seemed insurmountable.

One consideration associated with traditional gas development has been the surface disturbance required for access roads and well pads. As described in greater detail below, horizontal drilling provides a means to significantly reduce surface disturbance and a host of related concerns.

EXHIBIT 28: PROCESS OF SHALE GAS DEVELOPMENT (DURATION)

Mineral Leasing

Companies negotiate a private contract or lease that allows mineral development and compensates the mineral owners. Lease terms vary and can contain stipulations or mitigation measures pertinent to protect various resources. (Several weeks to years)

Permits

The operator must obtain a permit authorizing the drilling of a new well. Surveys, drilling plans, and other technical information are frequently required for a permit application. The approved permit may require site specific environmental protection measures. Other permits such as water withdrawal or injection permits may also be required. (Several weeks to months)

Road and Pad Construction

Once permits are received, roads are constructed to access the wellsite. Well pads are constructed to safely locate the drilling rig and associated equipment during the drilling process. Pits may be excavated to contain drilling fluids. (Several days to weeks)

Drilling and Completion

A drilling rig drills the well and multiple layers of steel pipe (called casing) are put into the hole and cemented in place to protect fresh water formations. (Weeks or months)

Hydraulic Fracturing

A specially designed fracturing fluid is pumped under high pressure into the shale formation. The fluid consists primarily of water along with a proppant (usually sand) and about 2% or less of chemical additives. This process creates fractures in rock deep underground that are "propped" open by the sand, which allows the natural gas to flow into the well. (Days)

Production

Once the well is placed on production, parts of the wellpad that are no longer needed for future operations are reclaimed. The gas is brought up the well, treated to a useable condition, and sent to market. (Interim Reclamation: days; Production: years)

Workovers

Gas production usually declines over the years. Operators may perform a workover which is an operation to clean, repair and maintain the well for the purposes of increasing or restoring production. Multiple workovers may be performed over the life of a well. (Several days to weeks)

Plugging and Abandonment/Reclamation

Once a well reaches its economic limit, it is plugged and abandoned according to State standards. The disturbed areas, including well pads and access roads, are reclaimed back to the native vegetation and contours or to conditions requested by the surface owner. (Reclamation Activity: Days; Full Restoration: Years)

Another set of considerations associated with traditional oil and gas development are the conflicts that arise from split estates. In some instances mineral rights and surface rights are not owned by the same party. This is referred to as "split estate" or "severed minerals". The condition of split estate is more prevalent in western states where the federal government owns much of the mineral rights[223]. In the mid-west and eastern states, where shale gas development resources are more prevalent, only 4% of the lands are associated with a federal split estate[224]. However, these same areas frequently have private-private split estate scenarios where the surface owner differs from the mineral estate owner. In these cases the mineral owner may be another individual or a business enterprise such as a coal company.

It is important to understand that surface owners who do not own minerals rights are still afforded certain protections.

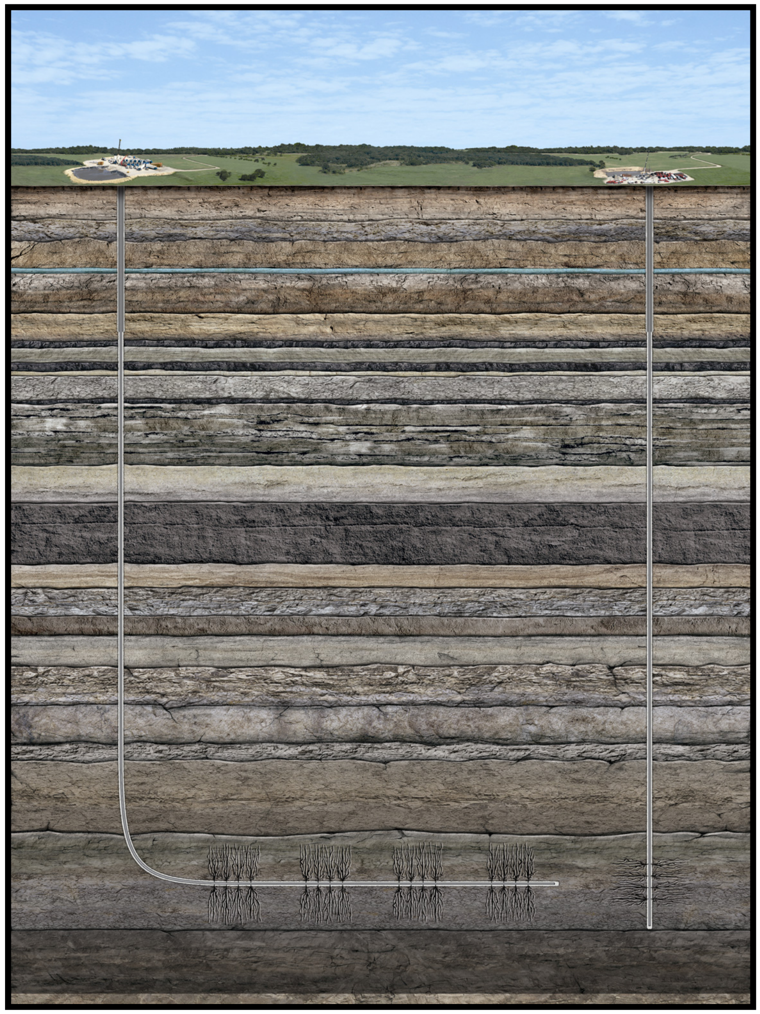
A split-estate situation, regardless of its nature, can result in conflicts—especially in areas where active mineral resource development is not commonplace. Land-owners can be surprised to find that the mineral lease holder is entitled to reasonable use of the land surface even though they do not own the surface. However, it is important to understand that surface owners who do not own minerals rights are still afforded certain protections. If the mineral owner does not own the surface where drilling will occur, a separate agreement may be negotiated (in some states it is required) with the land owner to ensure that he or she is compensated for the use of the land and to set requirements for reclaiming the land when operations are complete[225].

Shale gas development within or near existing communities has created challenges for production companies. New technologies have generally allowed these challenges to be met successfully. In some cases, a combination of modern shale gas technologies and the innovative use of BMPs has been required to allow development to continue without compromising highly valued community resources.

In one instance, Chesapeake Energy Corporation constructed a well pad near a popular Fort Worth community area, known as the Trinity Trail System, to develop natural gas from the Barnett Shale. The Trinity Trail System is located on private land and consists of a 35-mile network of paved and natural surface pathways. The drilling pad was constructed approximately 200 feet from one portion of the trail. During the initial planning stages, proposed use of this land for development of natural gas was met with significant opposition by the public. Maintaining healthy populations of upland hardwood forest habitat was important to the community because such woodlots are rare in urban settings. To address the concerns of the community, the company sponsored public meetings and opinion surveys; provided landscape plans; planted trees and shrubs; and enhanced the general area by improving irrigation and lowering maintenance requirements. The well pad was specifically designed to be as small as possible in order to reduce the well's footprint. Preventative construction practices were used that helped to preserve many of the existing trees. The construction zone was isolated from view using a 16-ft barrier fence with sound baffling. This approach benefitted both parties: the company was able to produce the shale gas, important community resources were protected, and at no point in the process was any portion of the trail closed[226].

The following discussions describe the general process of development with emphasis on the horizontal drilling and hydraulic fracturing technologies that are the hallmarks of modern shale gas production. The section also describes the environmental considerations that accompany shale gas development and the technologies and practices that are in place to prevent or minimize impacts.

EXHIBIT 29: HORIZONTAL AND VERTICAL WELL COMPLETIONS



Source: John Perez, Copyright ©, 2008

Horizontal Wells

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells (Exhibit 29). The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature[227,228,229]. The technologies utilized by operators to drill shale gas wells are similar to the drilling techniques that have been industry standards for drilling of conventional gas wells. Both horizontal drilling and hydraulic fracturing are established technologies with significant track records; horizontal drilling dates back to the 1930s and hydraulic fracturing has a history dating back to the 1950s[230]. The key difference between a shale gas well and a conventional gas well is the reservoir stimulation (large-scale hydraulic fracturing) approach performed on shale gas wells[231].

The evolution of the Barnett Shale play toward favoring horizontal wells resulted from improvements in the technology combined with the economic benefits of the greater reservoir exposure that a horizontal well provides over a vertical well. While both well types may be used to recover the resource, shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well

Both horizontal drilling and hydraulic fracturing are established technologies with significant track records; horizontal drilling dates back to the 1930s and hydraulic fracturing has a history dating back to the 1950s.

economics[232]. Exhibit 29 illustrates how horizontal drilling provides more exposure to a formation than does a vertical well. For example, in the Marcellus Shale in Pennsylvania, a vertical well may be exposed to as little as 50 ft of formation while a horizontal well may have a lateral wellbore extending in length from 2,000 to 6,000 ft within the 50- to 300-ft thick formation[233]. This increase in reservoir exposure creates a number of advantages over vertical wells drilling.

There are a wide range of factors that influence the choice between a vertical or horizontal well. While vertical wells may require less capital investment on a per well basis, production is often less economical. A vertical well may cost as much as $800,000 (excluding pad and infrastructure) to drill compared to a horizontal well that can cost $2.5 million or more (excluding pad and infrastructure)[234].

Source: ALL Consulting, 2008

Active Drilling Rig in the Barnett Shale Play

Reducing Surface Disturbance

Complete development of a 1-square mile section could require 16 vertical wells each located on a separate well pad. Alternatively, six to eight horizontal wells (potentially more), drilled from only one well pad, could access the same reservoir volume, or even more[235]. The low natural permeability of shale requires vertical wells to be developed at closer spacing intervals than conventional gas reservoirs in order to effectively manage the resource. This can result in initial development of vertical wells at spacing intervals of 40 acres per well, or less, to efficiently drain the gas resources from the tight shale reservoirs. In addition, horizontal drilling can significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat fragmentation, impacts to the public, and the overall environmental footprint. Devon Energy Corporation reports that the use of horizontal wells in the Barnett Shale has allowed the company to replace 3 or 4 vertical wells with a single horizontal well. While it is too early to determine the final well spacing that will most efficiently recover the gas resource in all basins, experience to date indicates that the use of horizontal well technology will significantly decrease the total environmental disturbance.

Exhibit 11 includes data on well spacing for some of the developing shale gas basins. Using this data it is possible to compare the development of a typical 640-acre (1 square mile) area with vertical versus horizontal wells. The spacing interval for vertical wells in the gas shale plays averages 40 acres per well for initial development. The spacing interval for horizontal wells is likely to be approximately 160 acres per well. Therefore, a 640-acre section of land could be developed with a total of 16 vertical wells, each on its own individual well pad, or by as few as 4 horizontal wells all drilled from a single multi-well drilling pad. Analysis performed in 2008 for the U.S. Department of the Interior estimated that a shallow vertical gas well completed in the Fayetteville Shale in Arkansas would have a 2.0-acre well pad, 0.10 miles of road and 0.55 miles of utility corridor, resulting in a total of 4.8 acres of disturbance per well[236]. The same source identified a horizontal well pad in Arkansas as occupying approximately 3.5 acres plus roads and utilities, resulting in a total of 6.9 acres. If multiple horizontal wells are completed from a single well pad it may require the pad to be enlarged slightly. Estimating that this enlargement will result in a 0.5-acre increase, the 4-well horizontal pad with roads and utilities would disturb an estimated total of 7.4 acres, while the 16 vertical wells would disturb approximately 77 acres. In this example, 16 vertical wells would disturb more than 10 times the area of 4 horizontal wells to produce the same resource volume. This difference in development footprint when considered in terms of both rural and urban development scenarios highlights the desire for operators to move toward horizontal development of gas shale plays.

Reducing Wildlife Impacts

Research has documented that activities associated with gas development can affect wildlife and its habitat during the exploration, development, operations, and abandonment phases[237]. The development of shale gas utilizing horizontal wells and multi-well pads not only reduces surface area disturbances by reducing the total number of wells drilled and well pad sites constructed, but also results in fewer roadways and utility corridors. This overall reduction in a project's footprint results in significantly less habitat disturbance while allowing for more operational flexibility. Furthermore, by drilling underneath sensitive areas such as wetlands, areas near streams and rivers and wilderness habitats, gas can be produced without disturbing some of these resources. This ability to reduce surface disturbance is especially important in certain critical habitats. For example, certain portions of New York (e.g., Catskill Park, the Shawangunk Ridge, the Hudson Highlands and the Poconos) are dominated by hardwood forests, which are important wildlife habitats that are susceptible to fragmentation[238].

Source: WVSORO

Drilling Rig in Rural Upshur County, West Virginia

In addition, state regulations and, in some cases, local ordinances include stipulations dictating operational restrictions to provide added protection for wildlife or sensitive resources. In the city of Flower Mound, Texas, ordinances have been adopted to protect the surface resources and allow for future growth of the community without detracting from the land value or sense of community. These ordinances prevent construction in or near streams or rivers, floodplains and sensitive upland forest to protect wildlife species and their associated habitats.

At the state level, special plans or waivers are required when surface use actions may affect threatened or endangered species. Such waivers must demonstrate that contemplated disturbances will not adversely impact the species in question. In Pennsylvania, wildlife are further protected on state lands (by the Pennsylvania Game Commission) by using lease agreements that require, whenever feasible, the use of existing timber and maintenance roads to access wells and avoidance of areas such as wetlands and unique and critical habitats for threatened or endangered species[239].

When disturbances to wildlife habitat are unavoidable, energy companies mitigate land disturbances by implementing land reclamation practices to restore disturbed land to original conditions. In general, reclamation practices (or mitigation measures) designed to protect and maintain wildlife will depend on project features, regional characteristics, and the potentially affected species. However, because technologies associated with modern shale gas development can reduce impacts in the first place, the need for additional protective restoration measures may also be reduced. Regardless of the situation, the timely reclamation of disturbed lands (e.g., re-seeding, land contouring, and re-vegetating) can minimize short and long-term disturbances to natural habitats[240].

Reducing Community Impacts

States, local governments, and industry can work together in the initial planning phase of development to minimize long term effects and to address citizen concerns such as traffic congestion, damage to roads, dust, and noise [241].The process of shale gas development, especially drilling and hydraulic fracturing, can create short-term increases in traffic volume, dust and noise. These nuisance impacts are usually limited to the initial 20- to 30-day drilling and completion period[242]. Along with increases in traffic volume, damage to road surfaces can occur if design parameters for traffic volume and weight loads are exceeded. Where these effects are an issue, developers have worked with authorities to adjust work schedules to help alleviate congestion; water unpaved roads to reduce dust; and adjust timing of some operations and install special sound barriers to reduce noise for nearby residents. When feasible, developers can also use avoidance practices to help minimize traffic congestion on heavily traveled roads. In the Barnett Shale play around the Dallas-Fort Worth International Airport, operators have constructed permanent pipelines to transfer produced water from well sites to disposal facilities, thereby

Source: Parker County Commissioner's Office

Tanker Trucks in Parker County, Texas

reducing traffic and potential damage to roads[243]. When these practices are coupled with the benefits of multiple directional wells from fewer pads, the number of access roads and associated traffic can be further reduced.

In many cases, developers have negotiated to compensate local municipalities for road damage that does occur as a result of their activities. Alternatively, they may negotiate road maintenance and repair agreements to ensure that damage to roadways are repaired and that the cost is absorbed by the drilling enterprises[244]. The Perryman Group, in their 2007 study of the Barnett Shale play, noted that although traffic volume is a legitimate concern in the area, developers were effectively addressing the issue through maintenance agreements so that road repairs do not adversely affect local taxpayers[245].

From a traffic perspective, members of the public or local municipalities often have the ability to limit traffic volume in residential areas by developing restrictions in neighborhood lease agreements or by developing ordinances that prevent road construction in certain areas, respectively. In urban areas these agreements can be used to coordinate local traffic patterns to minimize congestion, control speed limits to address safety concerns, and specify weight zones to reduce road damage.

With continued advances in technologies, modern developers are afforded a higher level of drilling flexibility than in the past. This provides producers with the ability to adjust their operational plans allowing them to access drilling locations that would otherwise be inaccessible. Although drilling circumstances vary by geologic region and well location, in many cases, shale gas plays are being developed with both vertically and horizontally drilled wells (Exhibit 29). Based on the current development activities of active gas shale basins, horizontal drilling has become the preferred method of drilling in most shale gas plays. Horizontal wells have also been used in many areas of the country to remotely access natural gas resources beneath existing infrastructure, buildings, environmentally sensitive areas, or other features that would prevent the use of vertical wells. The development of the Barnett Shale near Dallas-Fort Worth International Airport is a prime example of how development of urban areas is possible with horizontal wellbores[246].

Source: ALL Consulting, 2008

Shale Gas Activity at Dallas-Fort Worth International Airport

The purpose of ordinances and best management practices is to facilitate the development of the natural gas resource while protecting quality of life and environmental values in the surrounding areas.

Changes in practices during the drilling and completion of shale gas wells have evolved from the Barnett Shale play near Dallas-Fort Worth International Airport and other urban areas surrounding the airport. Development practices there have been altered to suit local ordinances implemented to lessen community impacts and protect environmental resources. These ordinances include detailed setbacks from residences, roadways, churches, and schools, and means to control visual and noise impacts including the required use of directional lighting[247]. This results in the use of BMPs for sound barriers and lighting. Typically, drilling operations in rural gas development areas continue around the clock until the well is completed. When these same operations moved into the urban areas around the cities of Arlington, Burleson, Cleburne, Fort Worth, Joshua and North Richland Hills, specific ordinances were developed requiring additional permitting, well set backs from properties, day-time and night-time noise limits, and directional lighting[248]. Directional lighting provides illumination of well sites for worker safety, directing the light downward and shielding the surrounding area to prevent illuminating neighboring residences, roads or other buildings[249].

Source : Chesapeake Energy Corporation, 2008

Insulation Blankets Used to Deaden Noise from Drilling Operations

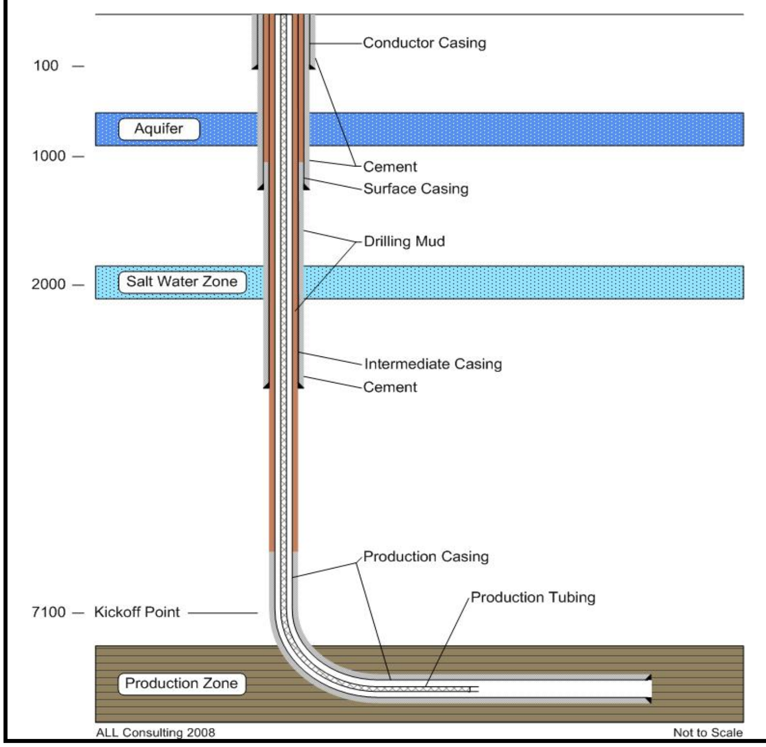
In a similar concept, these drilling rigs are also being outfitted with blanket-like enclosures that act as an acoustic barrier to reduce engine noise. Sound deadening technology is a BMP that is also being applied to reduce noises from compressor facilities in both rural and urban settings[250]. These sound barriers include developing alternative building materials with integral sound absorbing properties.

These "BMPs" are not appropriate for all operations and must be applied on a case-by-case basis. In some cases, a given BMP may actually be counter-productive. In other cases, a particular BMP may create other environmental, safety, or operational problems that must be weighed against each other. While BMPs have certain benefits in certain situations, they cannot be universally applied or required.

Protecting Groundwater: Casing and Cementing Programs

State oil and gas regulatory programs place great emphasis on protecting groundwater. Current well construction requirements consist of installing multiple layers of protective steel casing and cement that are specifically designed and installed to protect fresh water aquifers and to ensure that the producing zone is isolated from overlying formations. During the drilling process, a conductor and surface casing string are set in the borehole and cemented in place. In some instances, additional casing strings may be installed; these are known as intermediate casings (Exhibit 30[251]). After each string of casing is set, and prior to drilling any deeper in the borehole, the casing is cemented to ensure a seal is provided between the casing and formation or between two strings of casing[252]. Exhibit 30 illustrates the casing and cement that may be installed in shale gas wells and highlights how the casing can be set to isolate different water-bearing zones from each other. The exhibit shows the multiple strings of casing, layers of cement and the production tubing, which are all important parts of the well completion in preventing contamination of fresh water zones and assuring that the gas resource does not flow into other, lower pressure zones around the outside of the casing rather than flowing up the well to be produced and sold.[253].

EXHIBIT 30: CASING ZONES AND CEMENT PROGRAMS



The conductor casing serves as a foundation for the well construction and prevents caving of surface soils. The surface casing is installed to seal off potential freshwater-bearing zones, this isolation is necessary in order to protect aquifers from drilling mud and produced fluids. As a further protection of the fresh water zones, air-rotary drilling is often used when drilling through this portion of the wellbore interval to ensure that no drilling mud comes in contact with the fresh water zone. Intermediate casings, when installed, are used to isolate non-freshwater-bearing zones from the producing wellbore. Intermediate casing may be necessary because of a naturally over-pressured zone or because of a saltwater zone located at depth. The borehole area below an intermediate casing may be uncemented until just above the kickoff point for the horizontal leg. This area of wellbore is typically filled with drilling muds.

Each string of casing serves as a layer of protection separating the fluids inside and outside of the casing and preventing each from contacting the other. Operators perform a variety of checks to ensure that the desired isolation of each zone is occurring including ensuring that the casing used has sufficient strength, and that the cement has properly bonded to the casing[254]. These checks may include acoustic cement bond logs and pressure testing to ensure the mechanical integrity of casings. Additionally, state oil and gas regulatory agencies often specify the required depth of protective casings and regulate the time that is required for cement to set prior to additional drilling. These requirements are typically based on regional conditions and are established for all wildcat wells and may be modified when field rules are designated. These requirements are instituted by the state oil and gas agency to provide protection of groundwater resources[255]. Once the casing strings are run and cemented there could be five or more layers or barriers between the inside of the production tubing and a water-bearing formation (fresh or salt).

Analysis of the redundant protections provided by casings and cements was presented in a series of reports and papers prepared for the American Petroleum Institute (API)[256] in the 1980s. These investigations evaluated the level of corrosion that occurred in Class II injection wells. Class II injection wells are used for the routine injection of water associated with oil and gas production. The research resulted in the development of a method of calculating the probability (or risk) that fluids injected into Class II injection wells could result in an impact to a USDW. This research started by evaluating data for oil and gas producing basins to determine if there were natural formation waters present that were reported to cause corrosion of well casings. The United States was divided into 50 basins, and each basin was ranked by its potential to have a casing leak resulting from such corrosion.

Detailed analysis was performed for those basins in which there was a possibility of casing corrosion[257]. Risk probability analysis provided an upper bound for the probability of the fracturing fluids reaching an underground source of drinking water. Based on the values calculated, a modern horizontal well completion in which 100% of the USDWs are protected by properly installed surface casings (and for geologic basins with a reasonable likelihood of corrosion), the probability that fluids injected at depth could impact a USDW would be between 2×10^{-5} (one well in 200,000) and 2×10^{-8} (one well in 200,000,000) if these wells were operated as injection wells. Other studies in the Williston basin found that the upper bound probability of injection water escaping the wellbore and reaching an underground source of drinking water is seven changes in one million well-years where surface casings cover the drinking water aquifers[258].

These values do not account for the differences between the operation of a shale gas well and the operation of an injection well. An injection well is constantly injecting fluid under pressure and thus raises the pressure of the receiving aquifer, increasing the chance of a leak or well failure. A production well is reducing the pressure in the producing zone by giving the gas and associated fluid a way out, making it less likely that they will try to find an alternative path that could contaminate a fresh water zone. Furthermore, a producing gas well would be less likely to experience a casing leak because it is operated at a reduced pressure compared to an injection well. It would be exposed to lesser volumes of potentially corrosive water flowing through the production tubing, and it would only be exposed to the pumping of fluids into the well during fracture stimulations.

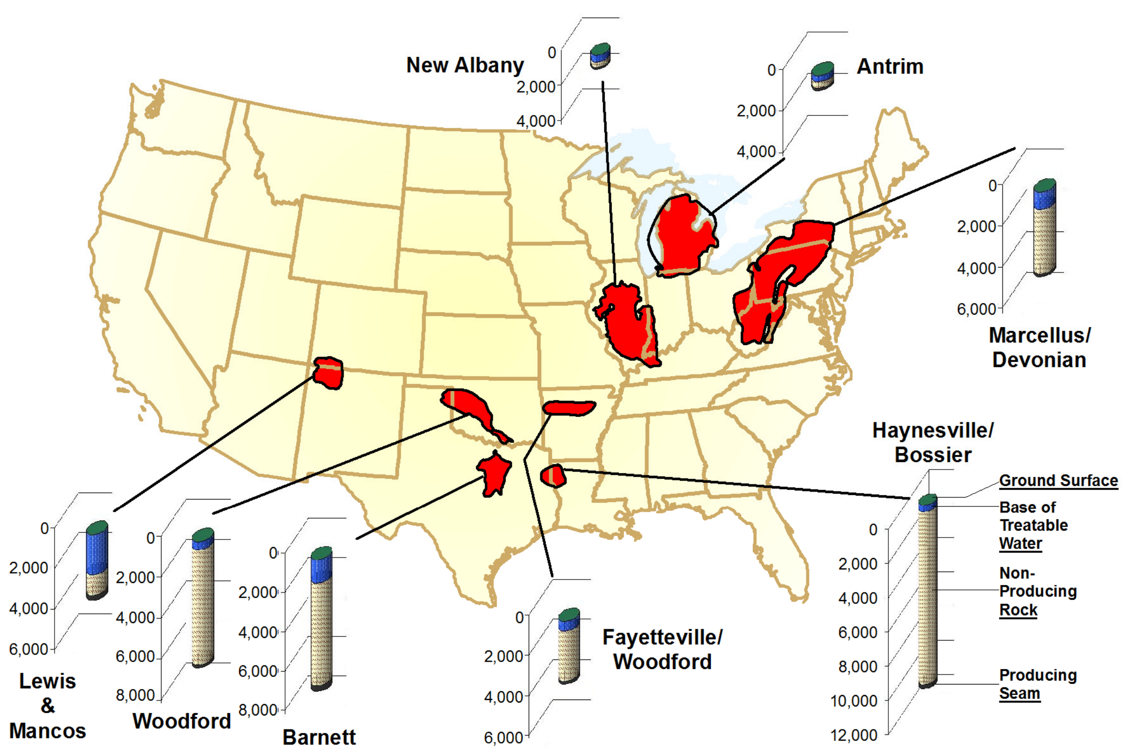
The API study included an analysis of wells that had been in operation for many years when the study was performed in the late 1980s, and does not account for advances that have occurred in equipment and applied technologies and changes to the regulations. As such, a calculation of the probability of any fluids, including hydraulic fracture fluids, reaching a USDW from a gas well would indicate an even lower probability; perhaps by as much as two to three orders of magnitude. The API report came to another important conclusion relative to the probability of the contamination of a USDW when it stated that:

> …for injected water to reach a USDW in the 19 identified basins of concern, a number of independent events must occur at the same time and go *undetected* [emphasis added]. These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing,] and the surface casing coupled with the unlikely occurrence of water moving long distances up the borehole past salt water aquifers to reach a USDW[259].

As indicated by the analysis conducted by API and others, the potential for groundwater to be impacted by injection is low. It is expected that the probability for treatable groundwater to be impacted by the pumping of fluids during hydraulic fracture treatments of newly installed, deep shale gas wells when a high level of monitoring is being performed would be even less than the 2 x 10^{-8} estimated by API.

In addition to the protections provided by multiple casings and cements, there are natural barriers in the rock strata that act as seals holding the gas in the target formation. Without such seals, gas and oil would naturally migrate to the earth's surface. A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so could never be tapped and produced in usable quantities. These sealing strata also act as barriers to vertical migration of fluids upward toward useable groundwater zones. Most shale gas wells (outside of those completed in the New Albany and the Antrim) are expected to be drilled at depths greater than 3,000 feet below the land surface (based on the data presented in Exhibit 11). Exhibit 31 compares estimated shallowest producible depth of the target ("pay") shale zone and the maximum base of treatable water. For any fluid present in the producing zone to reach treatable groundwater the fluid must migrate through these overlying zones.

EXHIBIT 31: COMPARISON OF TARGET SHALE DEPTH AND BASE OF TREATABLE GROUNDWATER



Source: Compiled from Various Data Sources

A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so it could never be tapped and produced in usable quantities. These sealing strata also act as barriers to vertical migration of fluids upward toward groundwater zones.

Drilling Fluids and Retention Pits

Drilling fluids are a necessary component of the drilling process; they circulate cuttings (rock chips created as the drill bit advances through rock, much like sawdust) to the surface to clear the borehole, they lubricate and cool the drilling bit, they stabilize the wellbore (preventing cave in), and control downhole fluid pressure[260]. In order to maintain sufficient volumes of fluids onsite during drilling, operators typically use pits to store make-up water used as part of the drilling fluids. Storage pits are not used in every development situation. In the case of shale gas development, drilling operations have been occurring in both urban and rural locations, requiring that drilling practices be adapted to facilitate development in both settings. Drilling with compressed air is becoming an increasingly popular 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[261]. 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[262].

Source: ALL Consulting, 2008

Lined Fresh Water Supply Pit from the Marcellus Shale Development in Pennsylvania

In rural areas, storage pits may be used to hold fresh water for drilling and hydraulic fracturing. In an urban setting, due to space limitations, steel storage tanks may be used. Tanks can also be used in a closed-loop drilling system. Closed-loop drilling allows for the re-use of drilling fluids and the use of lesser amounts of drilling fluids[263]. Closed-loop drilling systems have also been used with water-based fluids in environmentally sensitive environments in combination with air-rotary drilling techniques[264]. While closed-loop drilling has been used to address specific situations, the practice is not necessary for every well drilled. As discussed in the previous section, drilling is a regulated practice managed at the state level, and while state oil and gas agencies have the ability to require operators to vary standard practices, the agencies typically do so only when it is necessary to protect the gas resources and the environment.

In rural environments, storage pits may be used to hold water. They are typically excavated containment ponds that, based on the local conditions and regulatory requirements, may be lined. Pits can also be used to store additional make-up water for drilling fluids or to store water used in the hydraulic fracturing of wells.

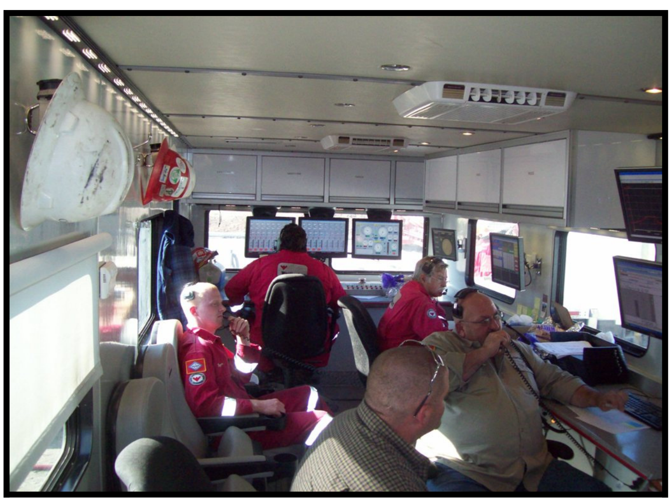
Water storage pits used to hold water for hydraulic fracturing purposes are typically lined to minimize the loss of water from infiltration (notice the black synthetic liner in the accompanying photograph). Water storage pits are becoming an important tool in the shale gas industry because the drilling and hydraulic fracturing of these wells often requires significant volumes of water as the base fluid for both purposes[265].

Hydraulic Fracturing

The other technological key to the economic recovery of shale gas is hydraulic fracturing. Hydraulic fracturing is a formation stimulation practice used to create additional permeability in a producing formation, thus allowing gas to flow more readily toward the wellbore[266,267]. Hydraulic fracturing can be used to overcome natural barriers to the flow of fluids (gas or water) to the wellbore. Such barriers may include naturally low permeability common in shale formations or reduced permeability resulting from near wellbore damage during drilling activities[268].

Stimulations are optimized to ensure that fracture development is confined to the target formation.

Hydraulic fracturing involves the pumping of a fracturing fluid into a formation at a calculated, predetermined rate and pressure to generate fractures or cracks in the target formation. For shale gas development, fracture fluids are primarily water-based fluids mixed with additives which help the water to carry sand proppant into the fractures. The sand proppant is needed to "prop" open the fractures once the pumping of fluids has stopped. Once the fracture has initiated, additional fluids are pumped into the wellbore to continue the development of the fracture and to carry the proppant deeper into the formation. The additional fluids are needed to maintain the downhole pressure necessary to accommodate the increasing length of opened fracture in the formation. Each rock formation has inherent natural variability resulting in different fracture pressures for different formations. The process of designing hydraulic fracture treatments involves identifying properties of the target formation including fracture pressure, and the desired length of fractures. The following discussion addresses some of the processes involved in the design of a hydraulic fracture stimulation of a shale gas formation.



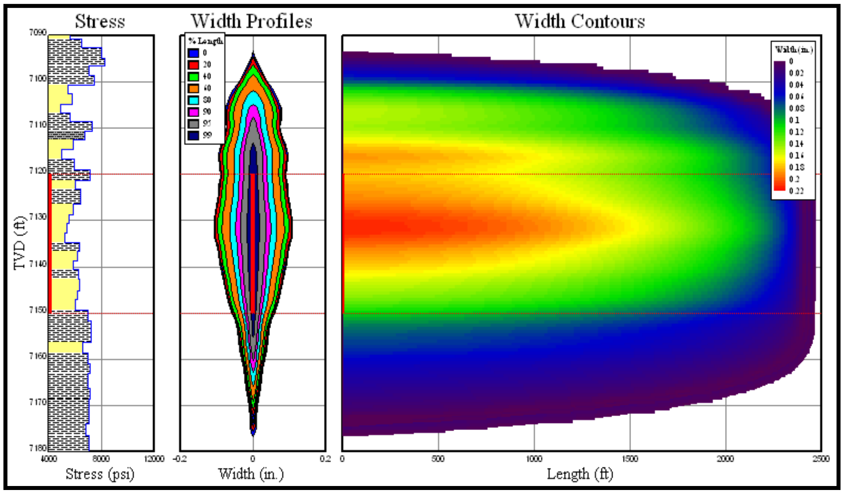
Source: ALL Consulting, 2008

A Fracture Stimulation Is Closely Monitored by Many Specialists (Fayetteville Shale - Arkansas)

Fracture Design

Modern formation stimulation practices are sophisticated, engineered processes designed to emplace fracture networks in specific rock strata[269]. A hydraulic fracture treatment is a controlled process designed to the specific conditions of the target formation (thickness of shale, rock fracturing characteristics, etc.). Understanding the *in-situ* reservoir conditions present and their dynamics is critical to successful stimulations. Hydraulic fracturing designs are continually refined to optimize fracture networking and maximize

EXHIBIT 32: EXAMPLE OUTPUT OF A HYDRAULIC FRACTURE STIMULATION MODEL



Source: Chesapeake, 2008

gas production. While the concepts and general practices are similar, the details of a specific fracture operation can vary substantially from basin to basin and from well to well.

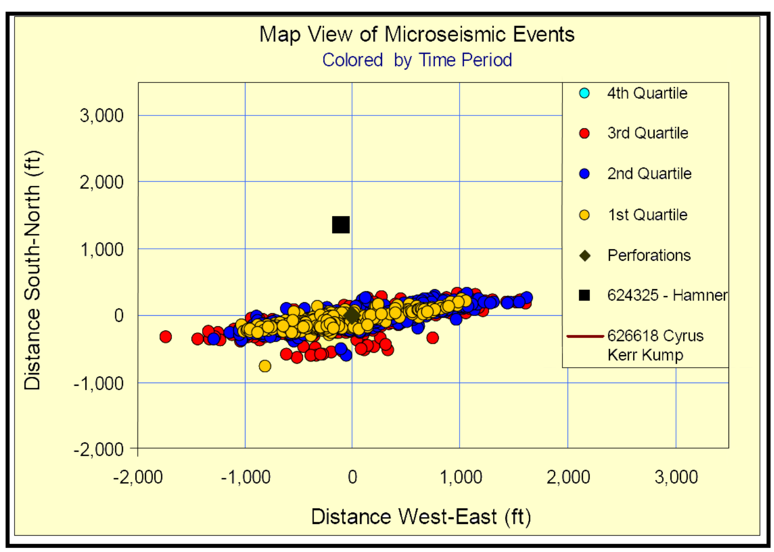
Fracture design can incorporate many sophisticated and state-of-the-art techniques to accomplish an effective, economic and highly successful fracture stimulation. Some of these techniques include modeling, microseismic fracture mapping, and tilt-meter analysis.

A computer model can be used to simulate hydraulic fracturing designs[270]. This approach helps maximize effectiveness and economically design a treatment event. The modeling programs allow geologists and engineers to modify the design of a hydraulic fracture treatment and evaluate the height, length, and orientation of potential fracture development (Exhibit 32)[271]. These simulators also allow the designers to use the data gathered during a fracture stimulation to evaluate the success of the fracture job performed. From these data and analyses, engineers can optimize the design of future fracture stimulations.

Additional advances in hydraulic fracturing design target analysis of hydraulic fracture treatments through technologies such as microseismic fracture mapping (Exhibit 33[272]) and tilt measurements[273]. These technologies can be used to define the success and orientation of the fractures created, thus providing the engineers with the ability to manage the resource through the strategic placement of additional wells, taking advantage of the natural reservoir conditions and expected fracture results in new wells.

As more formation-specific data are gathered, service companies and operators can optimize fracture patterns. Operators have strong economic incentives to ensure that fractures do not propagate beyond

EXHIBIT 33: MAPPING OF MICROSEISMIC EVENTS



Source: Oilfield Service Company, 2008

Operators have strong economic incentives to ensure that fractures do not propagate beyond the target formation and into adjacent rock strata.

the target formation and into adjacent rock strata[274]. Allowing the fractures to extend beyond the target formation would be a waste of materials, time, and money. In some cases, fracturing outside o f the target formation could potentially result in the loss of the well and the associated gas resource. Fracture growth outside of the target formation can result in excess water production from bounding strata. Having to pump and handle excess water increases production costs, negatively impacting well economics. This is a particular concern in the Barnett Shale of Texas where the underlying Ellenberger Group limestones are capable of yielding significant formation water.

Fracturing Process

Hydraulic fracturing of horizontal shale gas wells is performed in stages. Lateral lengths in horizontal wells for shale gas development may range from 1,000 feet to more than 5,000 feet. Because of the length of exposed wellbore, it is usually not possible to maintain a downhole pressure sufficient to stimulate the entire length of a lateral in a single stimulation event[275]. Because of the lengths of the laterals, hydraulic fracture treatments of horizontal shale gas wells are usually performed by isolating smaller portions of the lateral. The fracturing of each portion of the lateral wellbore is called a stage. Stages are fractured sequentially beginning with the section at the farthest end of the wellbore, moving uphole as each stage of the treatment is completed until the entire lateral well has been stimulated[276]. Horizontal wells in the various gas shale basins may be treated using two or more stages to fracture the entire perforated interval of the well. Each stage of a horizontal well fracture treatment is similar to a fracture treatment for a vertical shale gas well.

For each stage of a fracture treatment, a series of different volumes of fracture fluids, called sub-stages, with specific additives and proppant concentrations, is injected sequentially. Exhibit 34[277] presents an example of the sub-stages of a single-stage hydraulic fracture treatment for a well completed in the Marcellus Shale[278]. This is a single-stage treatment typical of what might be performed on a vertical shale well or for each stage of a multi-stage horizontal well treatment. The total volume of the sub-stages in Exhibit 34 is 578,000 gallons. If this were one stage of a four-stage horizontal well, the entire fracture operation would require approximately four times this amount, or 2.3 million gallons of water.

Before operators or service companies perform a hydraulic fracture treatment of a well (vertical or horizontal), a series of tests is performed. These tests are designed to ensure that the well, well equipment and hydraulic fracturing equipment are in proper working order and will safely withstand the application of the fracture treatment pressures and pump flow rates. The tests start with the testing of well casings and cements during the drilling and well construction process. Testing continues with pressure testing of hydraulic fracturing equipment prior to the fracture treatment process[279]. It should be noted that construction requirements for wells are mandated by state oil and gas regulatory agencies to ensure that a well is protective of water resources and is safe for operation.

EXHIBIT 34: EXAMPLE OF A SINGLE STAGE OF A SEQUENCED HYDRAULIC FRACTURE TREATMENT

Hydraulic Fracture Treatment Sub-Stage	Volume (gallons)	Rate (gal/min)
Diluted Acid (15%)	5,000	500
Pad	100,000	3,000
Prop 1	50,000	3,000
Prop 2	50,000	3,000
Prop 3	40,000	3,000
Prop 4	40,000	3,000
Prop 5	40,000	3,000
Prop 6	30,000	3,000
Prop 7	30,000	3,000
Prop 8	20,000	3,000
Prop 9	20,000	3,000
Prop 10	20,000	3,000
Prop 11	20,000	3,000
Prop 12	20,000	3,000
Prop 13	20,000	3,000
Prop 14	10,000	3,000
Prop 15	10,000	3,000
Flush	13,000	3,000

Notes:

Volumes are presented in gallons (42 gals = one barrel, 5,000 gals = ~120 bbls).

Rates are expressed in gals/minute, 42 gals/minute = 1 bbl/min, 500 gal/min = ~12 bbls/min.

Flush volumes are based on the total volume of open borehole, therefore as each stage is completed the volume of flush decreases as the volume of borehole is decreased.

Total amount of proppant used is approximately 450,000 pounds

Source: Arthur et al., 2008

After the testing of equipment has been completed, the hydraulic fracture treatment process begins. The sub-stage sequence is usually initiated with the pumping of an acid treatment. This acid treatment helps to clean the near-wellbore area which can be "damaged" (pores and pore throats become plugged with drilling mud or casing cement) as a result of the drilling and well installation process. The next sequence after the acid treatment is a slickwater pad, which is a water-based fracturing fluid mixed with a friction reducing agent. The pad is a volume of fracturing fluid large enough to effectively fill the wellbore and the open formation area. The slickwater pad helps to facilitate the flow and placement of the proppant further into the fracture network.

Source: Chesapeake Energy Corporation, 2008

Hydraulic Fracturing of a Marcellus Shale Well, West Virginia

After the pad is pumped, the first proppant sub-stage, combining a large volume of water with fine mesh sand is pumped. The next several sub-stagesin the stage increase the volume of fine-grained proppant while the volume of fluids pumped are decreased incrementally from 50,000 gallons (gals) to 30,000 gals. This fine-grained proppant is used because the finer particle size is capable of being carried deeper into the developed fractures[280]. In this example, the fine proppant sub-stages are followed by eight sub-stages of a coarser proppant with volumes from 20,000 gals to 10,000 gals. After the completion of the final sub-stage of coarse proppant, the well and equipment are flushed with a volume of freshwater sufficient to remove excess proppants from the equipment and the wellbore.

Hydraulic fracturing stimulations are overseen continuously by operators and service companies to evaluate and document the events of the treatment process. Every aspect of the fracture stimulation process is carefully monitored, from the wellhead and downhole pressures to pumping rates and density of the fracturing fluid slurry. The monitors

Every aspect of the fracture stimulation process is carefully monitored.

also track the volumes of each additive and the water used, and ensure that equipment is functioning properly. For a 12,000-bbl (504,000-gallon) fracture treatment of a vertical shale gas well there may be between 30 and 35 people on site monitoring the entire stimulation process.

The staging of multiple fracture treatments along the length of the lateral leg of the horizontal well allows the fracturing process to be performed in a very controlled manner. By fracturing discrete intervals of the lateral wellbore, the operator is able to make changes to each portion of the completion zone to accommodate site-specific changes in the formation. These site-specific variations may include variations in shale thickness, presence or absence of natural fractures, proximity to another wellbore fracture system, and boreholes that are not centered in the formation.

Fracturing Fluids and Additives

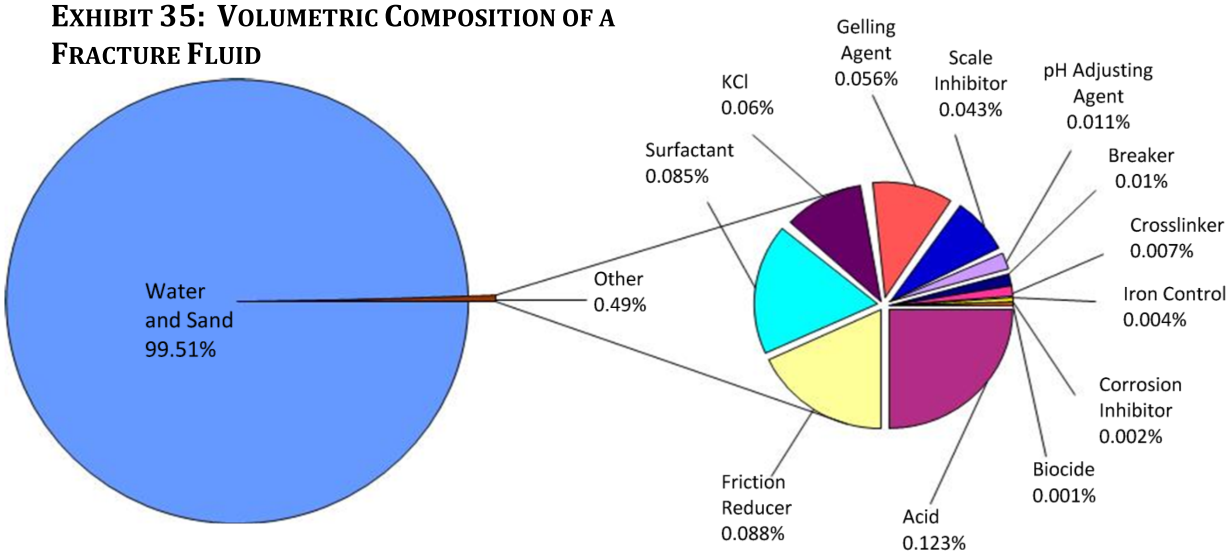
As described above, the current practice for hydraulic fracture treatments of shale gas reservoirs is to apply a sequenced pumping event in which millions of gallons of water-based fracturing fluids mixed with proppant materials are pumped in a controlled and monitored manner into the target shale formation above fracture pressure[281].

The fracturing fluids used for gas shale stimulations consist primarily of water but also include a variety of additives. The number of chemical additives used in a typical fracture treatment varies depending on the conditions of the specific well being fractured. A typical fracture treatment will use very low concentrations of between 3 and 12 additive chemicals depending on the characteristics of the water and the shale formation being fractured. Each component serves a specific, engineered purpose[282]. The predominant fluids currently being used for fracture treatments in the gas shale plays are water-based fracturing fluids mixed with friction-reducing additives (called slickwater)[283].

The addition of friction reducers allows fracturing fluids and proppant to be pumped to the target zone at a higher rate and reduced pressure than if water alone were used. In addition to friction reducers, other additives include: biocides to prevent microorganism growth and to reduce bio-fouling of the fractures; oxygen scavengers and other stabilizers to prevent corrosion of metal pipes; and acids that are used to remove drilling mud damage within the near-wellbore area[284]. These fluids are used not only to create the fractures in the formation but also to carry a propping agent (typically silica sand) which is deposited in the induced fractures.

Exhibit 35[285] demonstrates the volumetric percentages of additives that were used for a nine-stage hydraulic fracturing treatment of a Fayetteville Shale horizontal well. The make-up of fracturing fluid varies from one geologic basin or formation to another. Evaluating the relative volumes of the components of a fracturing fluid reveals the relatively small volume of additives that are present. The additives depicted on the right side of the pie chart represent less than 0.5% of the total fluid volume. Overall the concentration of additives in most slickwater fracturing fluids is a relatively consistent 0.5% to 2% with water making up 98% to 99.5%.

EXHIBIT 35: VOLUMETRIC COMPOSITION OF A FRACTURE FLUID



Source: ALL Consulting based on data from a fracture operation in the Fayetteville Shale, 2008

Because the make-up of each fracturing fluid varies to meet the specific needs of each area, there is no one-size-fits-all formula for the volumes for each additive. In classifying fracturing fluids and their additives it is important to realize that service companies that provide these additives have developed a number of compounds with similar functional properties to be used for the same purpose in different well environments. The difference between additive formulations may be as small as a change in concentration of a specific compound. Although the hydraulic fracturing industry may have a number of compounds that can be used in a hydraulic fracturing fluid, any single fracturing job would only use a few of the available additives. For example, in Exhibit 35 there are 12 additives used, covering the range of possible functions that could be built into a fracturing fluid. It is not uncommon for some fracturing recipes to omit some compound categories if their properties are not required for the specific application.

Most industrial processes use chemicals and almost any chemical can be hazardous in large enough quantities or if not handled properly. Even chemicals that go into our food or drinking water can be hazardous. For example, drinking water treatment plants use large quantities of chlorine. When used and handled properly, it is safe for workers and near-by residents and provides clean, safe drinking water for the community. Although the risk is low, the potential exists for unplanned releases that could have serious effects on human health and the environment. By the same token, hydraulic fracturing uses a number of chemical additives that could be hazardous, but are safe when properly handled according to requirements and long-standing industry practices. In addition, many of these additives are common chemicals which people regularly encounter in everyday life.

EXHIBIT 36: FRACTURING FLUID ADDITIVES, MAIN COMPOUNDS, AND COMMON USES.			
Additive Type	**Main Compound(s)**	**Purpose**	**Common Use of Main Compound**
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make-up remover, laxatives, and candy
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron Control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color
Note: The specific compounds used in a given fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales.			

Exhibit 36[286] provides a summary of the additives, their main compounds, the reason the additive is used in a hydraulic fracturing fluid, and some of the other common uses for these compounds. Hydrochloric acid (HCl) is the single largest liquid component used in a fracturing fluid aside from water; while the concentration of the acid may vary, a 15% HCl mix is a typical concentration. A 15% HCl mix is composed of 85% water and 15% acid, therefore, the volume of acid is diluted by 85% with water in its stock solution before it is pumped into the formation during a fracturing treatment. Once the entire stage of fracturing fluid has been injected, the total volume of acid in an example fracturing fluid from the Fayetteville shale was 0.123%, which indicates the fluid had been diluted by a factor of 122 times before it is pumped into the formation. The concentration of this acid will only continue to be diluted as it is further dispersed in additional volumes of water that may be present in the subsurface. Furthermore, if this acid comes into contact with carbonate minerals in the subsurface, it would be neutralized by chemical reaction with the carbonate minerals producing water and carbon dioxide as a byproduct of the reaction.

Water Availability

The drilling and hydraulic fracturing of a horizontal shale gas well may typically require 2to 4 million gallons of water[287], with about 3 million gallons being most common. It should be noted that the volume of water needed may vary substantially between wells. In addition the volume of water needed per foot of wellbore appears to be decreasing as technologies and methods improve over time. Exhibit 37[288] presents a table of estimated per-well water needs for four shale gas plays currently being developed.

EXHIBIT 37: ESTIMATED WATER NEEDS FOR DRILLING AND FRACTURING WELLS IN SELECT SHALE GAS PLAYS

Shale Gas Play	Volume of Drilling Water per well (gal)	Volume of Fracturing Water per well (gal)	Total Volumes of Water per well (gal)
Barnett Shale	400,000	2,300,000	2,700,000
Fayetteville Shale	60,000*	2,900,000	3,060,000
Haynesville Shale	1,000,000	2,700,000	3,700,000
Marcellus Shale	80,000*	3,800,000	3,880,000

* Drilling performed with an air "mist" and/or water-based or oil-based muds for deep horizontal well completions.
Note: These volumes are approximate and may vary substantially between wells.
Source: ALL Consulting from discussions with various operators, 2008

Water for drilling and hydraulic fracturing of these wells frequently comes from surface water bodies such as rivers and lakes, but can also come from ground water, private water sources, municipal water, and re-used produced water. Most of the producing shale gas basins occur in areas with moderate to high levels of annual precipitation as shown in Exhibit 38[289]. However, even in areas of high precipitation, due to growing populations, other industrial water demands, and seasonal variation in precipitation, it can be difficult to meet the needs of shale gas development and still satisfy regional needs for water.

Source: ALL Consulting, 2008

Little Red River, Arkansas

While the water volumes needed to drill and stimulate shale gas wells are large, they generally represent a small percentage of the total water resource use in the shale gas basins. Calculations indicate that water use will range from less than 0.1% to 0.8% by basin[290]. This volume is small in terms of the overall surface water budget for an area; however, operators need this water when drilling activity is occurring, requiring that the water be procured over a relatively short period of time. Water withdrawals during periods of low stream flow could affect fish and other aquatic life, fishing and other recreational activities, municipal water supplies, and other industries such as power plants. To put shale gas water use in perspective, the consumptive use of fresh water for electrical generation in the Susquehanna River Basin alone is nearly 150 million gallons per day, while the projected total demand for peak Marcellus Shale activity in the same area is 8.4 million gallons per day[291].

One alternative that states and operators are pursuing is to make use of seasonal changes in river flow to capture water when surface water flows are greatest. Utilizing seasonal flow differences allows planning of withdrawals to avoid potential impacts to municipal drinking water supplies or to aquatic or riparian communities. In the Fayetteville Shale play of Arkansas, one operator is constructing a 500-acre-ft impoundment to store water withdrawals from the Little Red River obtained during periods of high flow (storm events or hydroelectric power generation releases from Greer's Ferry Dam upstream of the intake) when excess water is available[292] (one acre-foot is equivalent to the volume of water required to cover one acre with one foot of water). The project is limited to 1,550 acre-ft of water annually. As additional mitigation, the company has constructed extra pipelines and hydrants to provide portions of this rural area with water for fire protection. Also included is monitoring of in-stream water quality as well as game and non-game fish species in the reach of river surrounding the intake. This design provides a water recovery system similar in concept to what

This project was developed with input from a local chapter of Trout Unlimited, an active conservation organization in the area, and represents an innovative environmental solution that serves both the community and the gas developer.

some municipal water facilities use. It will minimize the impact on local water supplies because surface water withdrawals will be limited to times of excess flow in the Little Red River. This project was developed with input from a local chapter of Trout Unlimited, an active conservation organization in the area, and represents an innovative environmental solution that serves both the community and the gas developer.

Because the development of shale gas is new in some areas, these water needs may challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies can help operators and communities to coexist and effectively manage local water resources. Understanding local water needs can help operators develop a water storage or management plan that will meet with acceptance in neighboring communities. Although the water needed for drilling an individual well may represent a small volume over a large area, the withdrawals may have a cumulative impact to watersheds over the short term. This potential impact can be avoided by working with local water resource managers to develop a plan outlining when and where withdrawals will occur (i.e., avoiding headwaters, tributaries, small surface water bodies, or other sensitive sources).

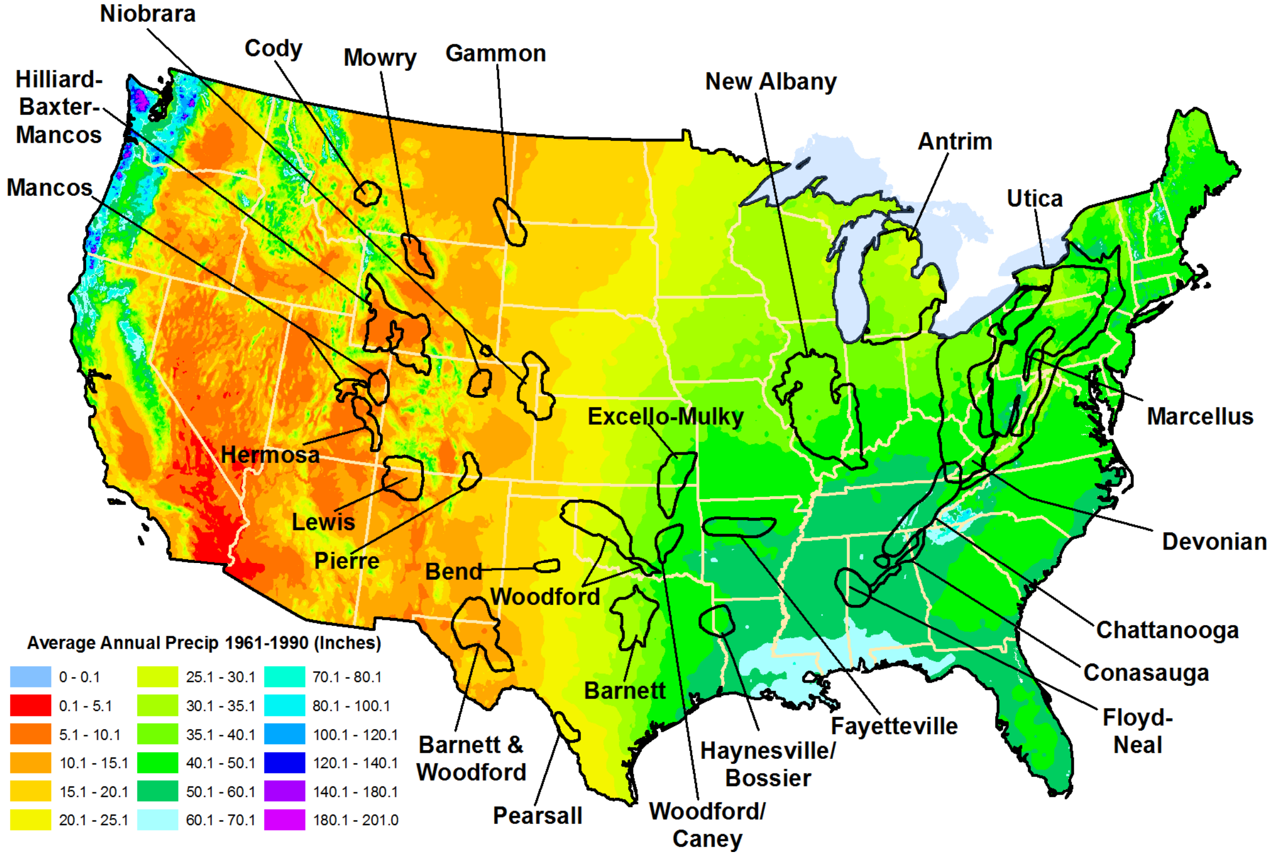
One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs.

In some basins, one key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region and even within a region such that developers will also need to understand local water laws[293] .

Water Management

After a hydraulic fracture treatment, when the pumping pressure has been relieved from the well, the water-based fracturing fluid, mixed with any natural formation water present, begins to flow back through the well casing to the wellhead. This produced water may also contain dissolved constituents from the formation itself. The dissolved constituents are naturally occurring compounds and may vary from one shale play to the next or even by area within a shale play. Initial produced water can vary from fresh (<5,000 ppm Total Dissolved Solids (TDS)) to varying degrees of saline (5,000 ppm to 100,000 ppm TDS[294] or higher). The majority of fracturing fluid is recovered in a matter of several hours to a couple of weeks. In various basins and shale gas plays, the volume of produced water may account for less than 30% to more than 70% of the original fracture fluid volume[295]. In some cases, flow back of fracturing fluid in produced water can continue for several months after gas production has begun[296].

EXHIBIT 38: ANNUAL RAINFALL MAP OF THE UNITED STATES



Source: NRCS

A suite of circumstances explains the disposition of fracturing fluids that are not recovered through production. However, it is important to understand that unrecovered fluids, if any, will remain contained within the target formations. Some of these fluids will occupy macro-porosity (typically natural fracture porosity) in the shale formation and some will occupy the micro-pore space vacated by the gas that is produced. Also, some of the fracturing fluids remain stranded in fractures within the reservoir rock that heal after fracturing, thus preventing the fluids from flowing back to the well. Some of these stranded fluids may flow back to the well in very small volumes over an extended time span. The longer contact time these fluids have with the formation further alters the chemistry of these fluids through increased dissolution of formation minerals, making them similar to the natural formation water. For these reasons it is not possible to unequivocally state that 100% of the fracturing fluids have been recovered or to differentiate flow back water from natural formation water.

Natural formation water has been in contact with the reservoir formation for millions of years and thus contains minerals native to the reservoir rock. The salinity, TDS, and overall quality of formation water vary by geologic basin and specific rock strata. After initial production, produced water can vary from brackish (5,000 ppm to 35,000 ppm TDS), to saline (35,000 ppm to 50,000 ppm TDS), to supersaturated brine (50,000 ppm to >200,000 ppm TDS)[297], and some operators report TDS values greater than 400,000 ppm[298]. The variation in composition changes primarily with changes in the natural formation water chemistry.

States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. Exhibit 39 summarizes current produced water management practices for the various shale gas basins, and is compiled from data collected from producers and regulatory agencies in these basins.

Underground injection has traditionally been the primary disposal option for oil and gas produced water. In most settings, this may be the best option for shale gas produced water. This process uses salt water disposal wells to place the water thousands of feet underground in porous rock formations that are separated from treatable groundwater by multiple layers of impermeable rock thousands of feet thick. Underground injection of the produced water is not possible in every play as suitable injection zones may not be available. Similar to a producing reservoir, there must be a porous and permeable formation capable of receiving injected fluids nearby. If such is not locally available, it may be possible to transport the produced water to a more distant injection site. In well developed urban plays such as the Barnett Shale around the City of Fort Worth, pipelines have been constructed to transport produced water to injection well disposal sites. This minimizes trucking the water and the resultant traffic, exhaust emissions, and wear on local roads[299]. Injection disposal wells are permitted under the federal Safe Drinking Water Act (SDWA), Underground Injection Control (UIC) program (or in the case of state primacy, under equivalent state programs), a stringently permitted and monitored process with many environmental safeguards in place.

Treatment of produced water may be feasible through either self-contained systems at well sites or fields or municipal waste water treatment plants or commercial treatment facilities. The availability of municipal or commercial treatment plants may be limited to larger urban areas where treatment facilities with sufficient available capacity already exist. As in underground injection, transportation to treatment facilities may or may not be practical[300].

Re-use of fracturing fluids is being evaluated by service companies and operators to determine the degree of treatment and make-up water necessary for re-use[301]. The practical use of on-site, self-contained treatment facilities and the treatment methods employed will be dictated by flow rate and total water volumes to be treated, constituents and their concentrations requiring removal, treatment objectives and water reuse or discharge requirements. In some cases it would be more practical to treat the water to a quality that could be reused for a subsequent hydraulic fracturing job, or other industrial use, rather than treating to discharge to a surface water body or for use as drinking water. At the time this Primer was developed there were plans to construct commercial waste water treatment facilities specifically designed for the treatment of produced water associated with shale gas development in some locations around the country[302]. The completion and success of such plants no doubt will be closely tied to the successful expansion of production in the various shale gas plays.

EXHIBIT 39: CURRENT PRODUCED WATER MANAGEMENT BY SHALE GAS BASIN.

Shale Gas Basin	Water Management Technology	Availability	Comments
Barnett Shale	Class II injection wells[303]	Commercial and non-commercial	Disposal into the Barnett and underlying Ellenberger Group[304]
	Recycling[305]	On-site treatment and recycling	For reuse in subsequent fracturing jobs [306]
Fayetteville Shale	Class II injection wells[307]	Non-commercial	Water is transported to two injection wells owned and operated by a single producing company [308]
	Recycling	On-site recycling	For reuse in subsequent fracturing jobs[309]
Haynesville Shale	Class II injection wells	Commercial and non-commercial	
Marcellus Shale	Class II injection wells	Commercial and non-commercial	Limited use of Class II injection wells[310,311]
	Treatment and discharge	Municipal waste water treatment facilities, commercial facilities reportedly contemplated[312]	Primarily in Pennsylvania
	Recycling	On-site recycling	For reuse in subsequent fracturing jobs[313]
Woodford Shale	Class II injection wells	Commercial	Disposal into multiple confining formations[314]
	Land Application		Permit required through the Oklahoma Corporation Commission[315]
	Recycling	Non-commercial	Water recycling and storage facilities at a central location[316]
Antrim Shale	Class II injection wells	Commercial and non-commercial	
New Albany Shale	Class II injection wells	Commercial and non-commercial	

New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water. The treated water can be reused as fracturing make-up water, irrigation water, and in some cases even drinking water. Recycling or re-use of produced water can decrease water demands and provide additional water resources for drought-stricken or arid areas. This allows natural gas-associated produced water to be viewed as a potential resource in its own right[317,318]. In one case, Devon Energy Corporation (Devon) is currently using water distillation units at centralized locations within the Barnett Shale play to treat produced water from hydraulic fracture stimulations[319]. As of early 2008, Devon had hydraulically fractured 50 wells using recycled water. Devon reports that the program is still in its testing and development stages. With further development, such specialized treatment systems may prove beneficial, particularly in more mature plays such as the Barnett; however, their practicality may be limited in emerging shale gas plays. Current levels of interest in recycling and reuse are high, but new approaches and more efficient technologies are needed to make treatment and re-use a wide-spread reality.

While challenges still exist, progress is being made. New technologies and new variations on old technologies are being introduced on a regular basis, and some industry researchers are pursuing ways to reduce the amount of treatment needed. In early 2009, studies were underway to determine the minimum quality of water that could successfully be used in hydraulic fracturing. If hydraulic fracturing procedures or fluid additives can be developed that will allow use of water with a high TDS content, then more treatment options become viable and more water can be re-used. Treatment and re-use of produced water could reduce water withdrawal needs as well as the need for additional disposal options. This approach could also help to resolve many of the concerns associated with these withdrawals.

Naturally Occurring Radioactive Material (NORM)

Some soils and geologic formations contain low levels of radioactive material. This naturally occurring radioactive material (NORM) emits low levels of radiation, to which everyone is exposed on a daily basis. Radiation from natural sources is also called background radiation. Other sources of background radiation include radiation from space and sources that occur naturally in the human body. This background radiation accounts for about 50% of the total exposure for Americans. Most of this background exposure is from radon gas encountered in homes (35% of the total exposure). The average person in the U.S. is exposed to about 360 millirem (mrem) of radiation from natural sources each year (a mrem, or one one-thousandth of a rem, is a measure of radiation exposure)[320]. The other 50% of exposures for Americans comes primarily from medical sources. Consumer products, industrial, and occupational sources contribute less than 3% of the total exposure[321].

In addition to the background radiation at the earth's surface, NORM can also be brought to the surface in the natural gas production process. When NORM is associated with oil and natural gas production, it begins as small amounts of uranium and thorium within the rock. These elements, along with some of their decay elements, notably radium$_{226}$ and radium$_{228}$[322], can be brought to the surface in drill cuttings and produced water. Radon$_{222}$, a gaseous decay element of radium, can come to the surface along with the shale gas.

When NORM is brought to the surface, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges[323]. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks[324].

The principal concern for NORM in the oil and gas industry is that, over time, it can become concentrated in field production equipment[325] and as sludge or sediment inside tanks and process vessels that have an extended history of contact with formation water[326]. Because the general public does not come into contact with oilfield equipment for extended periods, there is little exposure risk from oilfield NORM. Studies have shown that exposure risks for workers and the public are low for conventional oil and gas operations[327,328].

If measured NORM levels exceed state regulatory levels or OSHA exposure dose risks (29 CFR 1910.1096), the material is taken to licensed facilities for proper disposal. In all cases, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment for workers when radiation doses could exceed 5 mrem in one hour or 100 mrem in any five consecutive days. In addition to these federal worker protections, states have regulations that require operators to protect the safety and health of both workers and the public.

Currently there are no existing federal regulations that specifically address the handling and disposal of NORM wastes[d]. Instead, states producing oil and gas are responsible for promulgating and administering regulations to control the re-use and disposal of NORM-contaminated equipment, produced water, and oil-field wastes. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard oilfield waste. Conversely, if NORM concentrations are above regulatory limits, then the material must be disposed of at a licensed facility.

These regulations, standards, and practices ensure that oil and gas operations present negligible risk to the general public with respect to potential NORM exposure. They also present negligible risk to workers when proper controls are implemented[329].

Air Quality

Many of today's air quality rules were primarily designed to regulate emissions from single sources with large volumes of emissions output such as refineries, chemical plants, iron and steel manufacturing facilities, and electrical power generating sites. However, smaller sources such as individual shale gas well sites are also subject to state and federal regulations. Shale gas exploration and production operations are similar to most other conventional and unconventional natural gas exploration and production operations in terms of their air emissions. However, varying gas composition and the fact that there is little or no associated oil production affects the nature of potential emissions.

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[d] EPA does have drinking water standards for NORM.

Sources of Air Emissions

The exploration and production of shale gas may include a variety of potential air emission sources that change depending on the phase of operation. In the early phases of operation, emissions may come from such sources as drilling rigs whose engines may be fueled by either diesel or natural gas and from fracturing operations where multiple diesel-powered pumps are often used to achieve the necessary pressure. Other sources may include the well completion process, which may involve the venting or flaring of some natural gas, and vehicular traffic with engine exhaust and dust from unpaved roads.

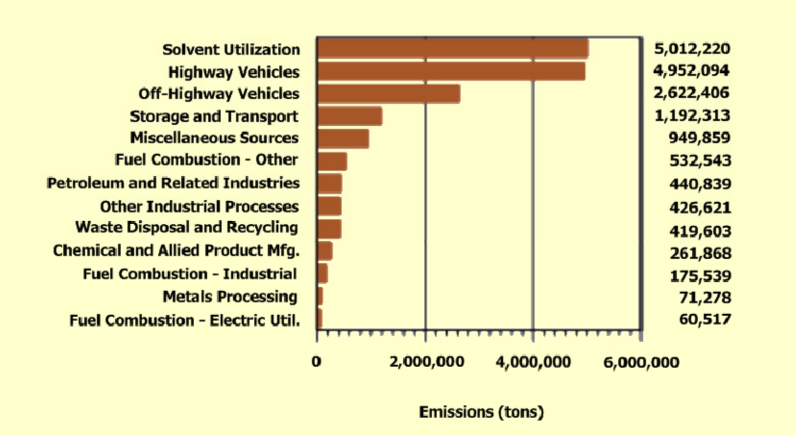
Once production has begun, emission sources may include compressors or pumps that may be needed to bring the produced gas up to the surface or up to pipeline pressure. Fugitive emissions such as leaks from pipe connections and associated equipment may also occur. Piping and pumping equipment may include pneumatic instrument systems, which, as part of their normal operations, release or bleed small amounts of natural gas into the atmosphere. Other sources of emissions in this phase of operations include flaring or blow down of gas in non-routine situations, dehydration units to remove water from the produced gas, and sulfur removal systems that may include flares and/or amine units.

Composition of Air Emissions

EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities[330]. These emissions and their sources are discussed below.

As in any construction or industrial activity, NO_x are formed when fossil fuel is burned to provide power to machinery such as compressor engines and during flaring operations. In addition, VOCs may be emitted during the dehydration of natural gas. VOC emissions are typically lower in natural gas activities than those associated with oil production because gas production is essentially a closed process from well to pipeline with fewer opportunities for emissions. In addition, emissions of benzene, toluene, ethylbenzene, and xylenes are low simply because these compounds do not exist in significant quantities in the natural gas stream. The oil and gas industry in general is a lesser contributor to air emissions than numerous other common sources (see Exhibit 40[331]). Further, oil and natural gas production contributes only 2% of the total benzene emissions in the U.S.[332], and shale gas

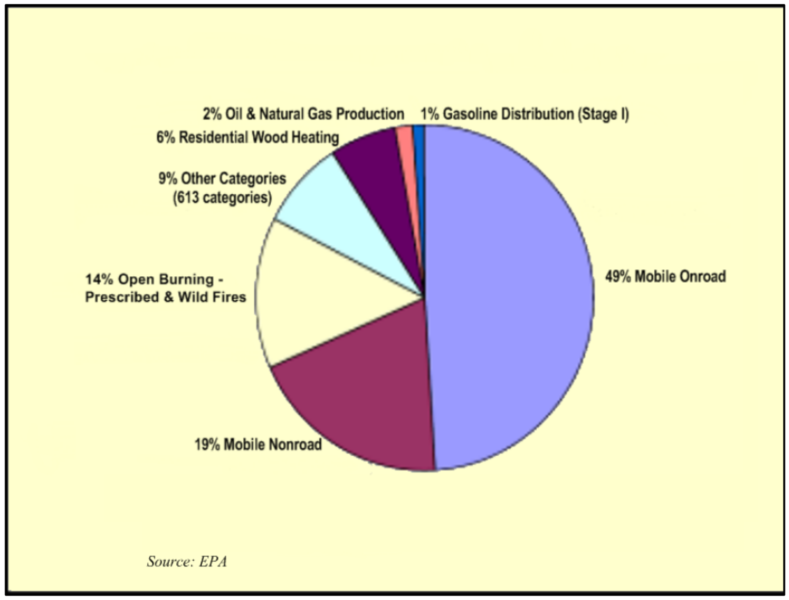
EXHIBIT 40: VOC EMISSIONS BY SOURCE CATEGORY



Source: EPA

represents a very small subset of this 2%.

EXHIBIT 41: BENZENE EMISSIONS BY SOURCE - 1999

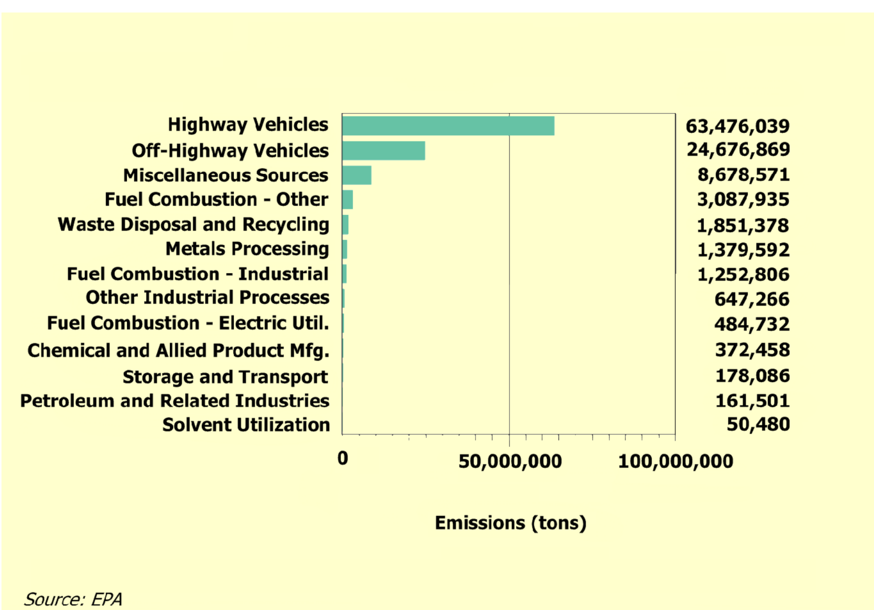


Particulate Matter (PM) may occur from dust or soil entering the air during pad construction, traffic on access roads, and diesel exhaust from vehicles and engines. In addition, CO may be emitted during flaring and from the incomplete combustion of carbon-based fuels used in engines. Flaring is seldom necessary with natural gas operations except during short periods of well testing, completions or workovers and non-routine situations such as a temporary pipeline closure. Exhibit 42[333] shows that CO emissions from the natural gas industry represent a very small part of the total[334].

SO_2 may form when fossil fuels containing sulfur are burned. Thus, SO_2 may be emitted from gasoline or diesel powered equipment used at a shale gas production site. However, emissions of SO_2 are typically very small for shale gas operations compared to coal or oil[335].

Ozone (O_3) itself is not released directly during natural gas development, but two of its main precursors, volatile organic compounds (VOCs) and NO_x, may combine with sunlight to form ground-level O_3 which can then be associated with exploration and production operations.

EXHIBIT 42: CO EMISSIONS BY SOURCE CATEGORY



Hydrogen sulfide (H_2S) emissions are not a concern in shale gas production as, based on discussions with operators from each of the major basins, the shale gas plays developed to date have not produced "sour" gas. If H_2S is encountered as production continues, both states and operators are well equipped to implement appropriate safety measures. States have well-established public safety and worker protection requirements in place and operators have access to proven procedures for working with natural gas contaminated with H_2S.

The American Petroleum Institute (API) has a Recommended Practice (RP 49) for Drilling and Well Servicing Operations Involving H_2S[336]. Producers voluntarily follow this practice to minimize the release of and exposure to H_2S. In areas where concentrations of H_2S may exceed 10 parts per million (ppm), producers implement an H_2S contingency plan. The plan includes appropriate instruction in the use of hydrogen sulfide safety equipment to all personnel present at all hydrogen sulfide hazard areas, gas detection where hydrogen sulfide may exist, and appropriate respiratory protection for normal and emergency use.

Methane (CH_4) is the principal component of natural gas and a known GHG. Although the processing of natural gas is essentially confined from the well to sales, CH_4 may be released as a fugitive emission from gas processing equipment, especially equipment in high pressure service such as pneumatic controls. Producers have strong economic incentives to limit fugitive methane emissions to the greatest degree possible in order to maximize delivery of methane to market. Therefore, they rely on multiple BMPs (e.g., low-bleed gauges and valves, inspection and maintenance programs, infra-red (IR) cameras, etc.[337]) to reduce any potential energy loss.

Another potential source of emissions in natural gas fields are compressor engines. Many gas compressor engines are fueled by natural gas from the lease. Engine manufacturers are constantly improving their technology to reduce the amount of NO_x emissions from their engines. One key has been the use of catalytic technologies to chemically convert NO_x into inert compounds. The addition of catalytic emissions controls has successfully lowered engine emissions from 20 grams per horsepower hour down to 2 grams of NO_x per horsepower hour or less. Also, the addition of air-fuel ratio controllers can be used to ensure the continuous low emissions performance of these engines. Recent EPA regulations require new engines to meet more stringent low NO_x emissions standards regardless of engine size or fuel.

Technological Controls and Practices

The best way to reduce air pollution is to prevent it from occurring in the first place. Pollution prevention can take many forms—upgrading equipment, improving operational practices, reducing waste through byproduct synergies, improving management practices, and installing emissions controls. Several government programs have been established that encompass avoidance, minimization, and mitigation strategies applicable to exploration and production activities. Some are mandatory regulations, as described in the Regulatory Framework section, while others are voluntary.

An example of the latter is the Natural Gas STAR program, a voluntary partnership between the EPA and the natural gas industry formed in 1995 to find cost-effective ways to ensure the natural gas industry is doing everything possible to prevent energy losses and to minimize GHG emissions[338]. The primary goals of the program are to promote technology transfer and implement cost-effective BMPs while reducing CH_4 emissions. The program provides information on many practices that not only reduce CH_4 emissions, but also works to retain greater volumes of natural gas for producers to sell.

Some of the most effective and economic technologies promoted by this program include:

1. Identification of high-bleed pneumatic devices (transducers, valves, controllers, etc.) and replacement with low-bleed ones to reduce fugitive product losses. Traditional pneumatic devices control processes by measuring changes in pressure, releasing small quantities of natural gas in the process. Newer devices are now available that perform the same functions while releasing much smaller amounts of gas.
2. Use of IR cameras in the field to visually identify any fugitive hydrocarbon leaks so that they may be rapidly repaired to reduce potential energy losses. These cameras are tuned to the wavelengths that are reflected by hydrocarbon gases, so that those normally-invisible gases actually become visible as "smoke" in the camera image, thus allowing companies to quickly detect and repair leaks.
3. Installation of flash tank separators in situations that require the use of dehydrators. This can recover 90 to 99% of the methane that would otherwise be flared or vented into the atmosphere[339].
4. Performance of green well completions and workovers. These shale gas operations typically use portable equipment to process and direct the produced natural gas into tanks or directly into the pipeline rather than the traditional practice of venting or flaring the gas. On average, green completions recover 53% of the natural gas that would otherwise have been flared or vented. That captured gas is now retained and sold to market[340].

Many other pollution reduction technologies and practices are described on EPA's GasSTAR web site. In 2004, the Methane to Markets Partnership was formed as a voluntary international program aimed at advancing the recovery and use of methane as a valuable clean energy source[341]. The program includes the oil and gas sector as a focus area along with coal mines, landfills, and the agricultural business. There are approximately 400 program members across the globe representing the oil and gas sector[342]. The collective results of these voluntary programs have been substantial. Total U.S. methane emissions in 2005 were over 11% lower than emissions in 1990, in spite of economic growth over that same time period[343]. EPA expects that these emissions will continue to fall in the future due to expanded industry participation and the ongoing commitment of the participating companies to identify and implement cost-effective technologies and practices.

Additional technologies and practices have been identified that may be used in some settings to reduce air emissions in shale gas fields. One such practice is the use of natural gas instead of diesel to fuel drilling rigs. Another emission-reducing practice applicable to some settings is the use of centralized processing facilities; this reduces vehicle trips, and therefore engine exhaust and dust emissions. Operators have also found that reducing glycol pump rates on dehydration units from their maximum setting to an optimized pump rate will minimize benzene, toluene, ethylbenzene, and total xylenes (BTEX) emissions. These units are often operated at a rate (based on at or near maximum throughput) that accommodates the initial, high rate of gas production from a field. However, as production rates decline, the dehydration units can be adjusted to conform to the lower gas throughput and reduce emissions. Other emission-reducing technologies include the installation of plunger lift systems into shale gas well heads to optimize gas production and reduce methane emissions associated with blowdown operations as well as the optimization of compressor and pump sizes to reduce the necessary horsepower and thus the subsequent exhaust emissions.

As with all operational practices, these BMPs must be applied on a case-by case basis. In some cases a given BMP may actually be counter-productive. In other cases, a particular BMP may create other environmental or operational problems that must be weighed against each other. While each BMP has certain benefits in certain situations, it cannot be universally applied or required.

State and federal requirements along with the technologies and practices developed by industry serve to limit air emissions from shale gas operations. As described earlier, state and federal requirements ensure that local conditions and other emission sources in the area are considered in issuing permits. In addition, advanced technologies and current practices serve to limit air emissions from modern shale gas development.

Summary

The primary differences between modern shale gas development and conventional natural gas development are the extensive use of horizontal drilling and multi-stage hydraulic fracturing. Horizontal drilling allows an area to be developed with substantially fewer wells than would be needed if vertical wells were used. The overall process of horizontal drilling varies little from conventional drilling, with casing and cementing being used to protect fresh and treatable groundwater. The use of horizontal drilling has not introduced new environmental concerns. On the contrary, the reduced number of horizontal wells needed, coupled with multiple wells drilled from a single pad, has significantly reduced surface disturbances and the associated impacts to wildlife and impacts from dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to help reduce community impacts, impacts to sensitive environmental resources, and interference with existing businesses.

Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proven to be a safe and effective stimulation technique. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. The multi-stage hydraulic fracture operations used in horizontal wells may require 3 to 4 million gallons of water. Since it is a relatively new use in these areas, withdrawals for hydraulic fracturing must be balanced with existing water demands. Once the fracture treatment is completed, most of the fracture water comes back to the surface and must be managed in a way that conserves and protects water resources. While challenges continue to exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users can be met and that surface and ground water quality is protected.

An additional consideration in shale gas development is the potential for low levels of naturally occurring radioactive material (NORM) to be brought to the surface. While NORM may be encountered in shale gas operations, there is negligible exposure risk for the general public and there are well established regulatory programs that ensure public and worker safety

Although the use of natural gas offers a number of environmental benefits over other fossil energy sources, some air emissions commonly occur during exploration and production activities. EPA sets standards, monitors the ambient air quality across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

Taken together, state and federal requirements, along with the technologies and practices developed by industry, serve to protect human health and to help reduce environmental impacts from shale gas operations.

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ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
bbls	barrels, petroleum (42 gallons)
bcf	billion cubic feet
BLM	Bureau of Land Management
BMP	Best Management Practices
Btu	British thermal units
CAA	Clean Air Act
CBNG	Coal Bed Natural Gas
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CWA	Clean Water Act
DRBC	Delaware River Basin Commission
EIA	Energy Information Administration
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
FR	Federal Register
ft	foot/feet
FWS	Fish and Wildlife Service
gal	gallon
GHG	Greenhouse Gases
GWPC	Ground Water Protection Council
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCl	Hydrochloric acid
IOGCC	Interstate Oil and Gas Compact Commission
IR	infra-red
Mcf	thousand cubic feet
MMcf	million cubic feet
mrem	millirem
mrem/yr	millirem per year
MSDSs	Material Safety Data Sheets
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory

NORM	Naturally Occurring Radioactive Material
NO_x	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NYDEC	New York State Department of Environmental Conservation
O_3	Ozone
OPA	Oil Pollution Act
OSHA	Occupational Safety and Health Administration
PM	Particulate Matter
ppm	parts per million
RAPPS	Reasonable and Prudent Practices for Stabilization
RCRA	Resource Conservation and Recovery Act
RP	Recommended Practice
RQ	Reportable Quantity
SARA	Superfund Amendments and Reauthorization Act
SCF	standard cubic feet
SDWA	Safe Drinking Water Act
SO_2	Sulfur Dioxide
SPCC	Spill Prevention, Control and Countermeasures
SRBC	Susquehanna River Basin Commission
STRONGER	State Review of Oil and Natural Gas Environmental Regulation, Inc.
SWDA	Solid Waste Disposal Act
tcf	trillion cubic feet
TDS	Total Dissolved Solids
tpy	tons per year
TRI	Toxics Release Inventory
UIC	Underground Injection Control
U.S.	United States
U.S.C.	United States Code
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VOC	Volatile Organic Compound
WQA	Water Quality Act
yr	year

DEFINITIONS

AIR QUALITY. A measure of the amount of pollutants emitted into the atmosphere and the dispersion potential of an area to dilute those pollutants.

AQUIFER. A body of rock that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

BASIN. A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

BIOGENIC GAS. Natural gas produced by living organisms or biological processes.

CASING. Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

COAL BED METHANE/NATURAL GAS (CBM/CBNG). A clean-burning natural gas found deep inside and around coal seams. The gas has an affinity to coal and is held in place by pressure from groundwater. CBNG is produced by drilling a wellbore into the coal seam(s), pumping out large volumes of groundwater to reduce the hydrostatic pressure, allowing the gas to dissociate from the coal and flow to the surface.

COMPLETION. The activities and methods to prepare a well for production and following drilling. Includes installation of equipment for production from a gas well.

CORRIDOR. A strip of land through which one or more existing or potential utilities may be co-located.

DISPOSAL WELL. A well which injects produced water into an underground formation for disposal.

DIRECTIONAL DRILLING. The technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad.

DRILL RIG. The mast, draw works, and attendant surface equipment of a drilling or workover unit.

EMISSION. Air pollution discharge into the atmosphere, usually specified by mass per unit time.

ENDANGERED SPECIES. Those species of plants or animals classified by the Secretary of the Interior or the Secretary of Commerce as endangered pursuant to Section 4 of the Endangered Species Act of 1973, as amended. See also **Threatened and Endangered Species**.

EXPLORATION. The process of identifying a potential subsurface geologic target formation and the active drilling of a borehole designed to assess the natural gas or oil.

FLOW LINE. A small diameter pipeline that generally connects a well to the initial processing facility.

FORMATION (GEOLOGIC). A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

FRACTURING FLUIDS. A mixture of water and additives used to hydraulically induce cracks in the target formation.

GROUND WATER. Subsurface water that is in the zone of saturation; source of water for wells, seepage, and springs. The top surface of the groundwater is the "water table."

HABITAT. The area in which a particular species lives. In wildlife management, the major elements of a habitat are considered to be food, water, cover, breeding space, and living space.

HORIZONTAL DRILLING. A drilling procedure in which the wellbore is drilled vertically to a kick-off depth above the target formation and then angled through a wide 90 degree arc such that the producing portion of the well extends horizontally through the target formation.

HYDRAULIC FRACTURING. Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing a network of fractures through which oil or natural gas can flow to the wellbore.

HYDROSTATIC PRESSURE. The pressure exerted by a fluid at rest due to its inherent physical properties and the amount of pressure being exerted on it from outside forces.

INJECTION WELL. A well used to inject fluids into an underground formation either for enhanced recovery or disposal.

LEASE. A legal document that conveys to an operator the right to drill for oil and gas. Also, the tract of land, on which a lease has been obtained, where producing wells and production equipment are located.

NORM (Naturally Occurring Radioactive Material). Low-level, radioactive material that naturally exists in native materials.

ORIGINAL GAS- IN- PLACE The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

PARTICULATE MATTER (PM). A small particle of solid or liquid matter (e.g., soot, dust, and mist). PM_{10} refers to particulate matter having a size diameter of less than 10 millionths of a meter (micro-meter) and $PM_{2.5}$ being less than 2.5 micro-meters in diameter.

PERMEABILITY. A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

PRIMACY. A right that can be granted to state by the federal government that allows state agencies to implement programs with federal oversight. Usually, the states develop their own set of regulations. By statute, states may adopt their own standards, however, these must be at least as protective as the federal standards they replace, and may be even more protective in order to address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

PRODUCED WATER. Water produced from oil and gas wells.

PROPPING AGENTS/PROPPANT. Silica sand or other particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.

PROVED RESERVES That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.

RECLAMATION. Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil, re-vegetation, and other work necessary to restore it.

SET-BACK. The distance that must be maintained between a well or other specified equipment and any protected structure or feature.

SHALE GAS. Natural gas produced from low permeability shale formations.

SLICKWATER. A water based fluid mixed with friction reducing agents, commonly potassium chloride.

SOLID WASTE. Any solid, semi-solid, liquid, or contained gaseous material that is intended for disposal.

SPLIT ESTATE. Condition that exists when the surface rights and mineral rights of a given area are owned by different persons or entities; also referred to as “severed estate”.

STIMULATION. Any of several processes used to enhance near wellbore permeability and reservoir permeability.

STIPULATION. A condition or requirement attached to a lease or contract, usually dealing with protection of the environment, or recovery of a mineral.

SULFUR DIOXIDE (SO_2). A colorless gas formed when sulfur oxidizes, often as a result of burning trace amounts of sulfur in fossil fuels.

TECHNICALLY RECOVERABLE RESOURCES The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.

THERMOGENIC GAS. Natural gas that is formed by the combined forces of high pressure and temperature (both from deep burial within the earth’s crust), resulting in the natural cracking of the organic matter in the source rock matrix.

THREATENED AND ENDANGERED SPECIES. Plant or animal species that have been designated as being in danger of extinction. See also **Endangered Species.**

TIGHT GAS. Natural gas trapped in a hardrock, sandstone or limestone formation that is relatively impermeable.

TOTAL DISSOLVED SOLIDS (TDS). The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.

UNDERGROUND INJECTION CONTROL PROGRAM (UIC). A program administered by the Environmental Protection Agency, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.

UNDERGROUND SOURCE OF DRINKING WATER (USDW). 40 CFR Section 144.3 An aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer.

WATER QUALITY. The chemical, physical, and biological characteristics of water with respect to its suitability for a particular use.

WATERSHED. All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

WELL COMPLETION. See **Completion**.

WORKOVER. To perform one or more remedial operations on a producing or injection well to increase production. Deepening, plugging back, pulling, and resetting the liner are examples of workover operations.

ENDNOTES

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TRUTHLAND

TruthlandMovie.com

AN ENERGY INDUSTRY DOCUMENTARY RESPONSE

TO THE "GASLAND" MOVIE

ONE MOTHER, LOTS OF QUESTIONS,

AND A PERSONAL JOURNEY TO FIND OUT THE TRUTH

August 2013

TRUTHLAND – THE MOVIE

TABLE OF CONTENTS

NOTES

- This document is a compilation of various portions of the Truthland movie webpage. While significant re-formatting of the material has occurred to facilitate this transition, the content is consistent with the original source.
  - http://www.truthlandmovie.com/
- Hyperlinks are imbedded within the document and indicated by blue font color.

TRUTHLAND – THE MOVIE

1.0 Truthland Movie

1.1 Overview

In the HBO movie “Gasland”, New York City filmmaker Josh Fox tried to scare people into thinking that natural gas development and hydraulic fracturing are new, unregulated, and dangerous.

In response to Gasland, the Independent Petroleum Association of America and Energy In Depth developed their own film documentary called “Truthland”. This film follows a Pennsylvanian mom, teacher, and farmer named Shelly, who after watching Gasland becomes concerned about the movie’s claims. Shelly lives with her family on a farm that’s been in her husband’s family since 1890. Of course, that farm also happens to sit atop the Marcellus Shale, one of the largest natural gas fields in the world. If accessing those resources wasn’t safe, she thought, then:

- What would happen when she turned on the faucet?
- Would it be safe for animals and kids?

Shelly needed to find out for herself, her family, and her community. So she hopped in the car and traveled across the country on her personal journey to find the truth about hydraulic fracturing. Shelly asked environmentalists, academics, and everyday people what they think about the process. Nobody got paid to talk – all they were asked was to tell the truth. The answers she received were drastically different from the information conveyed in Gasland. In short, Truthland corrects the claims within Gasland and sets the record straight.

Watch the Truthland Movie at: http://www.truthlandmovie.com/

1.2 The Story Line

Flammable faucets. Top-secret chemicals. Sick livestock. Ominous voice-overs. Grainy video. And that banjo … that incessant banjo.

Shelly had seen and heard enough.

Is hydraulic fracturing — one of many key processes used to produce America's enormous reserves of natural gas — as unsafe and environmentally ruinous as some have said? The way Gasland director Josh Fox tried so hard to portray it on HBO?

Shelly certainly had a stake in the answer. A teacher by trade from rural northeast Pennsylvania, Shelly lives with her husband, four children and granddaughter on a farm that's been part of her husband's family since 1890. Of course, that farm also happens to sit atop the Marcellus Shale, one of the largest natural gas fields in the world. If accessing those resources wasn't safe, she thought, then neither was her family. She owed it to them — and to herself — to find out the truth. After all, wells were being considered for her property.

So, like the good teacher she is, Shelly began by making a list, running through some of the scarier claims made in the film and pulling together a couple of questions specific to each. Questions like:
What's the deal with this dramatic "fire on water" scene in "Gasland"? If a gas well is drilled near your property, is that what happens to your faucet?

How about the film's claim that chemicals are getting into our water supply — and secret ones to boot? That doesn't sound right.

What about this town called Dimock, Pennsylvania? Gasland depicts it as an absolute wasteland, something straight out of the "Lord of the Rings." What's the real story out there? And what do the people who actually live there have to say about this whole thing?

Armed with serious questions and determined to find serious and credible answers, Shelly packs up her suitcase and hits the road for a trip across the country, making stops along the way to interview academics, environmentalists, regulators and industry experts — people who know a thing or two about the science, technology and history of producing oil and gas in America. And would you believe it? None of the experts who agreed to sit down with Shelly asked her for a dime. Which was only fair, really, since Shelly herself wasn't paid for her time or participation either.

Of course, if you ask Shelly, she'll tell you that she didn't exactly return from the trip empty-handed. She came back with a lot of facts, a lot of answers, and the peace of mind you get from having both those things close by. Not for nothin', but she also returned with a pretty snazzy video highlighting all the amazing people and places she visited during her trip. We call it "Truthland." Hopefully, upon watching it, you'll understand why.

2.0 Shelly Hears from the Experts

Presented in order of appearance in the film…

2.1 John Hanger – Former Secretary, Pennsylvania Department of Environmental Protection (PA DEP) - Harrisburg, PA

"We've never had one case of (hydraulic fracturing) fluid going down the gas well and coming back up and contaminating someone's water well."

Watch Interview

An expert on energy, environment, and the green economy, John previously served as secretary of the Pennsylvania's Department of Environmental Protection and commissioner of the state's Public Utility Commission. He currently serves as Special Counsel at the law firm Eckert Seamans and recently started his own practice, Hanger Consulting LLC.

Resources:

- John Hanger's popular "Facts of the Day" blog
- Sec. Hanger's shares views on Gasland with Philadelphia Inquirer

2.2 Joseph Martin, Ph.D., P.E. – Professor, Engineer, Drexel University - Philadelphia, PA

"There's almost no likelihood or possibility that methane could migrate laterally from a natural gas well."

Watch Interview

Joseph P. Martin, Ph.D., P.E. is a 29-year professor in the College of Civil, Architectural and Environmental Engineering at Drexel University. He holds three degrees in civil engineering—B.S. from Tufts University, M.S. from Northeastern University, and a Ph.D. from Colorado State — and is considered a leading expert in his field. In 2012, Martin was selected as the “Engineer of the Year” by the Delaware County chapter of the Pennsylvania Society of Professional Engineers.

Resources:

- Local news reports on Dr. Martin’s “Engineer of the Year” citation

2.3 Terry Engelder, Ph.D. – Professor of Geosciences, Penn State University - University Park, PA

“I have seen Gasland, and the flaw is that there’s a tremendous amount of innuendo in the movie.”

Watch Interview

Terry Engelder – known as the “father of the Marcellus” – is a professor of geosciences at Penn State and has previously served on posts at the U.S. Geological Survey and Columbia University, among other institutions. A leading authority (perhaps the leading authority) on the Marcellus, Engelder has authored and contributed to over 150 scientific papers on a number of geology-related topics, including shale. In 2011, Engelder was named one of the Top 100 global thinkers by Foreign Policy magazine.

Resources:

- Prof. Engelder chosen among Top 100 global thinkers by Foreign Policy magazine
- Video: Engelder provides updated information on new Marcellus resource estimates
- Ground Water Protection Council study mentioned by Prof. Engelder in the film

2.4 Brian Stawicki, Fred Haas – U.S. Steel employees - Lorain, OH

"Back in 2009, we both got laid off … But we got our jobs back because of the natural gas boom. It created our jobs back plus a lot more."

Watch Interview

Laid off in early 2009, the emergence of shale development in Ohio and continued growth of the industry in Pennsylvania and West Virginia meant greater demand for steel pipe and tubular products – and new opportunities for folks like Brian and Fred to secure high-wage jobs.

Resources:

- More information on U.S. Steel's Lorain Works facility
- NPR: Shale development brings new life to steel industry

2.5 Gary Hanson – Director, Red River Watershed Management Institute - Caddo Parish, LA

"It's literally impossible to (hydraulically fracture) into a groundwater zone."

Watch Interview

Gary is the director of the Red River Watershed Management Institute, a multidisciplinary education center featuring a 585-acre wetland, state-of-the-art water monitoring technology, and environmental assessment and monitoring laboratory. A respected hydrologist, Gary is frequently asked to contribute his time and expertise on issues relating to water conservation and management in the Haynesville Shale.

Resources:

- Gary's presentation to U.S. EPA on groundwater protection in Louisiana
- More on LSU-Shreveport Red River Watershed Management Institute

2.6 Elvis Bowman – Senior Pastor, Greater Mount Tabor Christian Center - Fort Worth, TX

"We have not experienced any of those problems … [The industry] did what they said they would do."

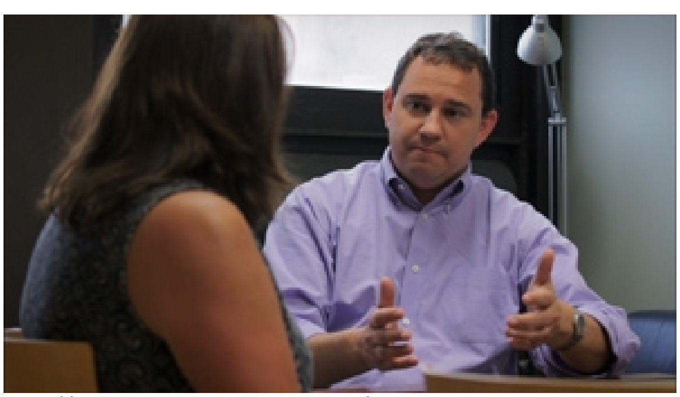
Watch Interview

The Greater Mount Tabor Christian Center was founded in 1965 by Pastor Bowman's father, Reverend E. L. Bowman. Over the past decade, Pastor Bowman has increased the membership of Greater Mount Tabor 100-fold, erected three new facilities for parishioners, organized over 60 different ministries, founded Fort Worth Human Services, Inc. and also started a Christian school associated with the church.

Resources:

- More information on the Greater Mount Tabor Christian Center
- Independent air quality analysis of Fort Worth, Texas – prepared by same investigators used by EPA

2.7 Dr. Michael Webber – Associate Director, Center for International Energy and Environmental Policy (CIEEP), University of Texas - Austin, TX



"This is a unique opportunity, a transformational opportunity for the U.S., and therefore, the world."

Watch Interview

The author of over 150 scientific articles, books, and columns, Michael is an expert on issues relating to energy, engineering, and national security. In addition, Michael serves on the board of advisors for Scientific American, holds four patents, and is one of the originators of the Pecan Street Project, a $30 million public-private partnership geared toward the promotion of smart grid technology and deployment.

Resources:

More information on Univ. of Texas' CIEEP program

Reviews and information on Michael's new book: "Changing the Way America Thinks about Energy"

2.8 Chuck Sylvester – Rancher, former director of National Western Stock Show - Weld County, CO

"[Methane in water] has been going on before there was any drilling, before even people knew what the word 'fracking' meant."

Watch Interview

In Gasland, Josh Fox attempts to blame methane in a Weld Co. water well on natural gas development – a claim that was subsequently responded to and debunked by the Colorado Oil & Gas Conservation Commission in a special fact sheet released by the agency in 2010. For his part, Mr. Sylvester, a lifelong resident of Weld County, was voted into the Colorado 4-H Hall of Fame in 2011.

Resources:

- "Gasland Debunked" fact sheet issued by environmental regulators in Colorado

2.9 Robert Sandell – Resident - Guilford Center, NY

"Well, when we first bought this place and moved in, the lady told me 'don't smoke in the shower,' and I wondered what she was talking about."

Watch Interview

Robert Sandell, a resident of Chenango County, N.Y., has been able to light his faucet on fire for years – despite residing in an area where no Marcellus activity takes place. According to the N.Y. Dept. of Environmental Conservation, methane in groundwater along the state's southern tier has been a natural feature of the environment for hundreds of years.

Resources:

- Article in local newspaper reporting on what DIDN'T cause Mr. Sandell's faucet to ignite

2.10 Loren Salsman – Resident, Environmental Technician - Dimock, PA

"I moved in in '95, and immediately we noticed some gas in the water, which turned out to be methane, and we always had a high amount of iron in the water as well."

Watch Interview

A 17-year resident of Dimock, Loren is a Penn State-trained environmental technician with decades of experience conducting site assessments at Superfund sites, military bases, bulk petroleum storage facilities, gas stations, and industrial plants. As he wrote in a recent blog post on the national controversy that has come to envelope his town: “I know contamination, and there’s none in Dimock.” Loren previously served as a public health sanitarian specializing in residential well water testing.

Resources:

- Commentary and video from Loren from his home in Dimock, Pa.
- Online home of “Dimock Proud,” a group of local residents that formed last year to correct the record on their town

2.11 Walter Brooks – Farmer - Susquehanna County, PA

“Gas companies came in, made a lot of extra jobs for people that were unemployed, and saved a lot of farms around the community — mine included.”

Watch Interview

Walter farms his land in Susquehanna Co., Pa., but like many farmers in rural Pennsylvania, he and his family fell upon hard times a couple years back owing to lower commodity prices and rising debt to the banks. Thanks to responsible Marcellus development in his area, Walter was able to pay off that debt and save a little extra for his family – all without having to sacrifice the quality of the land from which his livelihood was derived.

Resources:

- Comprehensive study of Susquehanna Co. water wells indicates presence of natural methane, unrelated to oil and gas development

2.12 Scott Roberts – Former Deputy Secretary, Pennsylvania Department of Environmental Protection - New Cumberland, PA

"Multiple layers of protection: cement, steel, cement, steel, cement. Production tubing on the inside. … You can see nothing's going to get in or out of this pipe."

Watch Interview

Recently retired from DEP after more than 25 years of service, Scott spent his whole career protecting the health and safety of Pennsylvania residents. Among his career highlights: Working with Democrats and Republicans from Pennsylvania's congressional delegation earlier this decade to secure more than $1 billion in additional federal funding to remediate the state's highest-priority abandoned coal mines.

Resources:

- Additional information on Scott's long career as an environmental regulator in Pennsylvania
- Citation accompanying 2010 "Mayfly Award" awarded to Scott by Western Pennsylvania Coalition for Abandoned Mine Reclamation

3.0 The Facts on Fracturing and Other Stuff Too

The history of fracturing technology's safe use in America extends all the way back to the Truman administration, with more than 1.2 million wells completed via the process since 1947. But only recently has the term "hydraulic fracturing" entered the public's vocabulary, a function of the enormous opportunities that the application of fracturing and horizontal drilling are making possible all around the country through the development of abundant resources from shale.

So what's this technology all about? And how does what you may have heard about the process square with the actual facts? In this section, we highlight – and correct – some of the most pervasive myths that have come to surround the debate over fracturing.

3.1 What is hydraulic fracturing?

It's not a "drilling technique," for starters. It's a technology that's used to enhance the flow of energy from a well once the drilling is done and the rig and derrick are removed from the scene. On average, it's a process that takes about three to five days to complete start to finish. Once the fracturing operation is done, the well is considered "completed," and, once the flowback is collected, is now ready to produce oil and/or natural gas for years, even decades, to come.

- EPA: Background information on hydraulic fracturing
- AXPC: Real facts behind fracture stimulation technology (2010)
- IPAA: "Three E's" fracturing fact sheet (2009)

3.2 So it's only used for oil and natural gas, right?

Actually, no. Over the past 60 years, hydraulic fracturing has been used for a wide variety of purposes, from stimulating the flow of water from water wells, to bringing geothermal wells into commercial viability. It's even been called on by EPA to serve as a remediation tool for cleaning up Superfund sites – bet you didn't know that one.

- EPA: A Citizens Guide to Superfund Cleanup and Hydraulic Fracturing (2001)
- MIT: The Future of Geothermal Energy (2006)

3.3 How does the process work in an oil/gas context?

After the well is drilled and multiple layers of casing and cement are installed, the drilling crew is replaced by a fracturing crew, which then gets to work on preparing the water-based solution for delivery to the formation. Water is far and away the most important aspect of a successful fracturing operation, as it not only creates the tiny fissures in the deep shale rock that liberate the natural gas, but also acts as a carrier and delivery mechanism for the sand, which helps keep those newly created fissures open so that resources can be collected.

Of course, water alone can't create those tiny fractures in the rock – you need to apply some pressure as well. At a typical fracturing operation, dozens of "pump trucks" will be called in to help deliver the pressurized water down the wellbore. The solution itself is made up almost entirely of water and sand, 99.5 percent on average. The small percentage of materials that remain are additives that control the growth of bacteria in the wellbore (which, left unchecked, can corrode the pipes). Other additives alter the surface tension of the water so that it can be easily sent down the hole at the start, and then brought back up again when the fracturing operation is complete.

- Dept. of Energy: Modern Shale Gas Development in the U.S. – A Primer (2009)
- Video: 3-D rendering of the fracturing process (CHK, 2011)

3.4 Isn't the composition of fracturing fluids a secret?

No, it's not. As mentioned, greater than 99 percent of the fluid is composed of water and sand, and the small fraction of what remains includes many common industrial and even household materials that millions of American consumers use every day. By both weight and volume, the most prominent of these materials is a substance known as "guar." Sounds scary, right? It's actually an emulsifying agent more typically found in ice cream. In fact, the ice cream industry hasn't been too pleased with us recently, since, thanks to shale, we've been using a good bit of the stuff as of late (though the guar bean growers don't seem to mind).

The truth is, there isn't a single "hazardous" additive used in the fracturing process that's hidden from public view. On the federal level, operators are bound by requirements of the Community Right-to-Know Act (passed in 1986), which mandate that detailed product information sheets be drawn up, updated, and made immediately available to first-response and emergency personnel in case of an accident on-site. More recently, an effort led by the U.S. Department of Energy and the Ground Water Protection Council (GWPC) culminated in the creation of FracFocus.org – a searchable, nationwide database with specific well-by-well information on the additives used in the fracturing process. States themselves have also upped the ante, with no fewer than a dozen updating their regulations over the past 12 months to promote additional disclosure.

3.5 So what's with all the controversy over "trade secrets"?

In rare cases, a company may ask that a certain "constituent" contained within a larger "additive" set be protected, though even then under law that information must be released to response and medical personnel in case of an emergency. Even without an emergency, companies still disclose the general name of the constituent in question, its common industrial uses, and even the volumes at which it is being deployed. Indeed, the vast majority of these are considered "non-hazardous" by EPA – quite the contrast from what you've read in the papers.

- GWPC: Nationwide, searchable, well-by-well chemical disclosure database
- Halliburton: Regional breakdown of both the additives and constituents used in fracturing solutions
- Range Resources: Completion reports (with detailed fluid disclosure) for more than 120 individual wells

3.6 I hear a lot of talk about "shale gas." How is that different from natural gas?

No difference at all. Shale gas is simply natural gas that comes from shale formations instead of other rock strata like limestone or sandstone. Natural gas from shale is just as clean as natural gas from any of those other rock layers, and just as versatile as a reliable, low-cost power and fuel source for America. The difference is: in shale, there's just a whole lot more natural gas to be found. That's good news for folks who use natural gas to cook their food and heat their home – and even better news for companies in America that use natural gas to make everything from face-creams to fertilizers.

- API: Facts about natural gas from shale
- Union of Concerned Scientists: Great primer on clean energy aspects of natural gas

3.7 Folks say hydraulic fracturing will cause my water to catch on fire. Is that true?

It took an awful long time for the facts to show up to the dance on this one, but finally media are starting to catch up to the truth behind this easily discredited myth. It all started in 2009 with the release of the anti-natural gas film Gasland, whose most memorable scene was of a man in Colorado lighting his faucet on fire and then blaming it on hydraulic fracturing. After the film was released, regulators in Colorado issued a detailed fact sheet seeking to "correct several errors" made in the film – including the one about the flaming faucet.

According to regulators, the well featured in Gasland "contained biogenic gas that was not related to oil and gas activity." So where did the methane come from? "[T]the water well completion report … shows that it penetrated at least four different coal beds. The occurrence of methane in the coals of the Laramie Formation has been well documented."

Further east, states like Pennsylvania were instructing homeowners how to safely vent methane from their water wells long before deep shale development came to town. Here's a how-to guide issued by the Department of Environmental Protection (DEP) in 2004, and another pamphlet released by Penn State Univ. in 2006.

- Colorado regulators' fact sheet: Addressing myths in Gasland (2010)
- EID: Gasland Debunked (June 2010)
- MI Dept. of Public Health: Naturally occurring methane in Michigan's water wells (1965)
- PA DEP: Fact sheet on mitigating methane in water wells (2002)
- Flashback: Methane reported in PA water wells in early 1980s (Pittsburgh Post-Gazette)
- Fox on film: Gasland director admits methane in NY water wells goes back 80 years

3.8 Nearly 65 years of use, and not one case of groundwater contamination caused by hydraulic fracturing? How can that be possible?

You don't have to take our word for it. Recently, an official with the U.S. Department of the Interior told Congress that "we have not seen any impacts to groundwater as a result of hydraulic fracturing." In May 2011, EPA administrator Lisa Jackson told the U.S. Senate that she wasn't aware "of any proven case where the fracking process itself affected water." She confirmed that once again in April 2012, when she told reporters that "in no case have we made a definitive determination that the fracking process has caused chemicals to enter groundwater." Letters from dozens of state environmental agencies – offices that have been regulating the fracturing process for decades — also confirm the safety of the technology.

Of course, just because fracturing's record is good doesn't mean there's never been a single issue with a single one of the more than 500,000 natural gas wells active in America today. Accidents, though rare, have occurred – and as long as humans beings are doing the work, we'll never be able to tell you that an accident in the future is impossible.

Drilling a natural gas well — or any well, for that matter – is not an endeavor without risk. Neither is crossing the street. The key question is: are those risks manageable? And in the case of natural gas, are regulations in place to ensure those risks are being managed in the proper way? Five-hundred thousand wells and 150 years of safe operations later, we'd submit that they are. With that many wells out there, wouldn't it be pretty clear by now if they weren't?

- Video: EPA administrator — "I am not aware of any proven case where the fracking process itself affected water."(May 2011)
- Letters: State regulators set the record straight on safety, performance of fracturing technology
- EIA: Updated data on number of producing natural gas wells in America (2011)

3.9 Speaking of regulation: What's this I keep hearing about a "loophole" in the law?

You've probably heard a lot about this one. Getting the public to believe that hydraulic fracturing is essentially unregulated is critical to some folks' strategy of shutting it down. But here's the truth: States have regulated the fracturing process for more than six decades now, and by any legitimate measure have compiled an impressive record of enforcement in that time.

Unfortunately, and for reasons that have nothing to do with that record of performance, some believe that EPA should step in and create a new role for itself — directly regulating the process from its offices in Washington, D.C. To do that, legislation has been introduced that its proponents say is about closing a "loophole" in the law preventing companies from having to disclose the contents of their solutions. In fact, it's not about either of these things, as any plain-reading of the actual bill will confirm.

Truth is, hydraulic fracturing has never in its nearly 65-year history been regulated under the Safe Drinking Water Act. Language adopted by bipartisan majorities of Congress in 2005 simply reaffirmed that fact. Here's a question for you: If a law at no point in its history had ever been used to regulate you in the first place, how can you be considered "exempt" from it now?

- Wheeling News-Register: Experts set the record straight on myth of "loophole" (2010)
- Fact Sheet: Federal statutes in play at each stage of the oil and gas development process
- Roll-call vote on Energy Policy Act of 2005 — Senate // House

3.10 Does hydraulic fracturing cause earthquakes?

According to USGS scientist Bill Ellsworth: "We find no evidence that [hydraulic fracturing] is related to the occurrence of earthquakes that people are feeling. We think that it's more intimately connected to the wastewater disposal." Ellsworth has also criticized the media's role in misrepresenting his work: "I was greatly surprised to see how words were being used in the press in ways that were inappropriate … We don't see any connection between fracking and earthquakes of any concern to society."

Wastewater injection wells serve many purposes, including long-term CO2 storage, enhanced oil recovery, and permanent disposal of fluids from industrial, non-oil-and-gas related activities. There are about 500,000 injection wells across the United States, and according to EPA, approximately 144,000 "Class II" wastewater injection sites in operation. Class II, one of six classes in total recognized by EPA, covers wastewater from oil and natural gas development.

The link between injection wells and low-level seismicity has been understood and acknowledged for decades, according to the U.S. Department of the Interior. In the 1960s, a series of small earthquakes around Denver were linked to disposal wells receiving wastewater from a nearby chemical plant. USGS has also noted that where these isolated incidents have occurred, it is easily manageable and making simple changes (i.e. reducing flow rates) safely mitigates any discernable risk.

- U.S. Dept. of the Interior: Is the Recent Increase in Felt Earthquakes in the Central US Natural or Manmade?
- Science Magazine (1968): Wastewater disposal triggers earthquakes near Denver, Colorado
- CNBC: Does Fracking Cause Earthquakes? (interview with Bill Ellsworth)
- EID: U.S. Geological Survey says no link between earthquakes and HF
- EID-Ohio: Experts confirm Ohio quakes not linked to HF

3.11 Isn't there a study out there that says natural gas from shale is dirtier than coal?

Indeed, "out there" is probably the best way to describe it. No need to spend too much time on a paper that's been debunked now by the U.S. Department of Energy, Council on Foreign Relations' Michael Levi , Carnegie Mellon University, and even his own colleagues on campus. But last April, two professors from Cornell made quite a stir by releasing a study that suggested natural gas from shale scored worse on greenhouse gases than coal.

Sure, we could tell you the paper was bought and paid for by the Ithaca-based Park Foundation, which funnels tens of millions of dollars a year to opposition groups working to institute a nationwide ban on fracturing. And sure, we could mention that both authors are actively involved in campaigns to prevent shale development from taking place in New York – they even wear pins! But we don't want you to think we're afraid of taking on the substance of the argument. So if you're interested in a point-by-point rebuttal of the study, click here. And if you're interested in seeing what other prominent third-party experts have to say about the paper, go ahead and take a look below.

- EID: Five Things to Know about the Cornell Shale Paper – Long Rebuttal // Fact Sheet
- U.S. Dept. of Energy rebuttal: Lifecycle analysis of natural gas extraction and delivery (2011)
- Carnegie Mellon researcher: "We don't think [Cornell] is using credible data and some of the assumptions they're making are biased." (POLITICO, Aug. 2011)
- Council on Foreign Relations' Michael Levi: "I worry about what this paper says about the peer review process and the way the press treats it." (April 2011)
- You can learn more at FracFocus.org, API's Energy from Shale page, ANGA.us, HydraulicFracturing.com, or, of course, Energy In Depth.

4.0 What They are Saying

The experts have a lot to say about hydraulic fracturing.

4.1 Independent Studies

"[T]here is at present little or no evidence of groundwater contamination from hydraulic fracturing of shales at normal depths. No evidence of chemicals from hydraulic fracturing fluid has been found in aquifers as a result of fracturing operations."

– "Fact-Based Regulation for Environmental Protection in Shale Gas Development," Energy Institute, University of Texas at Austin (p. 18, February 2012)

"[T]here is substantial vertical separation between the freshwater aquifers and the fracture zones in the major shale plays. The shallow layers are protected from injected fluid by a number of layers of casing and cement — and as a practical matter fracturing operations cannot proceed if these layers of protection are not fully functional."

– "The Future of Natural Gas," Massachusetts Institute of Technology (p. 15, 2010)

"[B]ased on over sixty years of practical application and a lack of evidence to the contrary, there is nothing to indicate that when coupled with appropriate well construction; the practice of hydraulic fracturing in deep formations endangers ground water. There is also a lack of demonstrated evidence that hydraulic fracturing conducted in many shallower formations presents a substantial risk of endangerment to ground water."

– "State Oil and Natural Gas Regulations Designed to Protect Water Resources," U.S. Department of Energy and Ground Water Protection Council (p. 39, May 2009)

"Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers."

– “Modern Shale Gas Development in the United States: A Primer,” U.S. Department of Energy and Ground Water Protection Council (p. ES-4, April 2009)

“EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection…”

– “Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,” U.S. Environmental Protection Agency (executive summary, p. ES-16, 2004)

4.2 State/Federal Regulators

“I’m not aware of any proven case where the fracking process itself has affected water.”
– Lisa Jackson, U.S. Environmental Protection Agency Administrator (May 24, 2011)

“Everybody in this room understands that hydraulic fracturing doesn’t connect to the groundwater…It’s almost inconceivable that we would ever contaminate, through the fracking process, the groundwater.”

– John Hickenlooper (D), Governor of Colorado and former petroleum geologist (Aug. 2, 2011)
“We’ve never had one case of fracking fluid going down the gas well and coming back up and contaminating someone’s water well.”

– John Hanger, former Secretary of Pennsylvania’s Department of Environmental Protection (as seen in Truthland)

“I’ve yet to see a single impact of fracking actually directly communicating with fresh groundwater resources…Again and again and again, I never see a single incidence of fracking causing this direct communication that we keep hearing about.”

– Scott Perry, Director of Pennsylvania’s Bureau of Oil and Gas Management (June 28, 2011)

“We have never had any instance of groundwater contamination from hydraulic fracturing — ever. For any fluid, frac fluid, to migrate up a mile, two miles to the water table is impossible. You are more likely to hit the moon with a Roman candle.”

– Elizabeth Ames Jones, Texas Railroad Commission (June 3, 2011)

“No verified or documented instances of harm to groundwater from HF [hydraulic fracturing].”

– Bob Anthony, Oklahoma Corporation Commission (March 30, 2011)

“Although an estimated 80,000 wells have been fractured in Ohio, state agencies have not identified a single instance where groundwater has been contaminated by hydraulic fracturing operations.”

– “Ohio Hydraulic Fracturing State Review,” State Review of Oil and Natural Gas Environmental Regulations, Inc. (January 2011)

“IOGCC member states have all stated that there have been no cases where hydraulic fracturing has been verified to have contaminated drinking water.”

– Interstate Oil and Gas Compact Commission, a multi-state organization of oil and gas regulators (IOGCC website)

“There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing.”

– Cathy Foerster, Alaska Oil and Gas Conservation Commission (2009)

“To the knowledge of the Colorado Oil and Gas Conservation Commission staff, there has been no verified instance of harm to groundwater caused by hydraulic fracturing in Colorado.”

– David Neslin, former Director of the Colorado Oil and Gas Conservation Commission (2009)

"The Louisiana Office of Conservation is unaware of any instance of harm to groundwater in the State of Louisiana caused by the practice of hydraulic fracturing."

– James Welsh, Louisiana Commissioner of Conservation (2009)

"There is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way."

– Harold Fitch, Director of the Michigan Office of Geological Survey (2009)

"In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time."

– Fred Steece, former Oil and Gas Supervisor for the South Dakota Department of Environment and Natural Resources (2009)

"We have had no reports of well damage due to fracking."

– Paul Schmierbach, Environmental Program Manager for the Tennessee Department of Environmental Conservation (2009)

4.3 Academics/Scientists/Engineers

"You can't save the forest if you don't have gas. It's one of the solutions we need to reduce deforestation and reduce the two million people who die every year because of indoor air pollution because they use firewood."

-Kandeh Yumkella, co-chair, United Nation's Sustainable Energy for All Initiative (June 19, 2012)

“We didn’t find (anything) happening related to shale gas that called for draconian measures in terms of regulations or prohibitions.”

– Chip Groat, Director, Center for International Energy and Environmental Policy at the University of Texas at Austin (March 12, 2012)

“There have been fears that hydraulic fracturing fluid injected at depth could reach up into drinking water aquifers. But, the injection is typically done at depths of around 6,000 to 7,000 feet and drinking water is usually pumped from shallow aquifers, no more than one or two hundred feet below the surface. Fracturing fluids have not contaminated any water supply and with that much distance to an aquifer, it is very unlikely they could.”

– Mark Zoback, Professor of Geophysics at Stanford University and member of the Secretary of Energy Committee on Shale Gas Development (August 30, 2011)

“As a New Yorker and hydrogeologist whose business is focused on protecting the environment, I am confident that Marcellus shale development in New York will not come at the expense of our water resources.”

– John Conrad, Senior Hydrogeologist for Conrad Geoscience Corporation (October 23, 2011)

“I have been working in hydraulic fracturing for 40+ years and there is absolutely no evidence hydraulic fractures can grow from miles below the surface to the fresh water aquifers.”

– Stephen A. Holditch , Head of the Department of Petroleum Engineering at Texas A&M University, Member of the Secretary of Energy’s Advisory Board Shale Gas Subcommittee (October 4, 2011)

5.0 Truthland in the News

- Youngstown Vindicator: ‘Truthland’ film takes pro-fracking approach (August 13, 2012)
- WDTV: Residents gather for documentary on fracking (August 8, 2012)
- Williamsport Sun Gazette: Some Natural Gas Truths Get Platform (August 5, 2012)

- The Allegheny Front: In the Scrum Over Fracking and Public Opinion, Movies Take Center Stage (August 4, 2012)
- The Daily Jefferson: Coalition Views Film Purporting to ‘Get the Facts Out’ (August 3, 2012)
- North County Public Radio: “Truthland” Ignites Fracking Debate (August 2, 2012)
- Williamsport Sun Gazette: Panelists, film share benefits of gas industry (August 1, 2012)
- Charleston Daily Mail: ‘Truthland’ Film to be shown for free (July 31, 2012)
- Innovation Trail: Screening of Pro-Fracking Film Turns Hostile (July 31, 2012)
- The Buffalo News: ‘Hydro-Fracking’ film draws crowd, exchange of barbs (July 27, 2012)

STATE OF COLORADO OIL & GAS CONSERVATION COMMISSION

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The documentary *Gasland* has attracted wide attention. Among other things, it alleges that the hydraulic fracturing of oil and gas wells has contaminated nearby water wells with methane in a number of states including Colorado. Because an informed public debate on hydraulic fracturing depends on accurate information, the Colorado Oil and Gas Conservation Commission (COGCC) would like to correct several errors in the film's portrayal of the Colorado incidents.

Background

Methane is a natural hydrocarbon gas that is flammable and explosive in certain concentrations. It is produced either by bacteria or by geologic processes involving heat and pressure. Biogenic methane is created by the decomposition of organic material through fermentation, as is commonly seen in wetlands, or by the chemical reduction of carbon dioxide. It is found in some shallow, water-bearing geologic formations, into which water wells are sometimes completed. Thermogenic methane is created by the thermal decomposition of buried organic material. It is found in rocks buried deeper within the earth and is produced by drilling an oil and gas well and hydraulically fracturing the rocks that contain the gas. In Colorado, thermogenic methane is generally associated with oil and gas development, while biogenic methane is not.

The analytical methods use to differentiate between the two types of methane are well-known, scientifically accepted, and summarized in a well-known presentation by Dennis Coleman and papers by I.R. Kaplan and Dennis Coleman. These works, in turn, cites nearly 75 other references related to the topics of methane generation, "fingerprinting," forensic investigations, and stable isotope geochemistry.

Based upon our review of hundreds of Colorado gas samples over many years, the COGCC is able to differentiate between biogenic and thermogenic methane using both stable isotope analysis of the methane and compositional analysis of the gas. In the Denver-Julesburg and Piceance Basins, the COGCC has consistently found that biogenic gas contains only methane and a very small amount of ethane, while thermogenic gas contains not just methane and ethane but also heavier hydrocarbons such as propane, butane, pentane, and hexanes.
As explained below, *Gasland* incorrectly attributes several cases of water well contamination in Colorado to oil and gas development when our investigations determined that the wells in question contained biogenic methane that is not attributable to such development.

The Weld County Wells

Gasland features three Weld County landowners, Mike Markham, Renee McClure, and Aimee Ellsworth, whose water wells were allegedly contaminated by oil and gas development. The COGCC investigated complaints from all three landowners in 2008 and 2009, and we issued written reports summarizing our findings on each. We concluded that Aimee Ellsworth's well contained a mixture of biogenic and thermogenic methane that was in part attributable to oil and gas development, and Mrs. Ellsworth and an operator reached a settlement in that case.

However, using the same investigative techniques, we concluded that Mike Markham's and Renee McClure's wells contained biogenic gas that was not related to oil and gas activity. Unfortunately, *Gasland* does not mention our McClure finding and dismisses our Markham finding out of hand.

The Markham and McClure water wells are both located in the Denver-Julesburg Basin in Weld County. They and other water wells in this area draw water from the Laramie-Fox Hills Aquifer, which is composed of interbedded sandstones, shales, and coals. Indeed, the water well completion report for Mr. Markham's well shows that it penetrated at least four different coal beds. The occurrence of methane in the coals of the Laramie Formation has been well documented in numerous publications by the Colorado Geological Survey, the United States Geological Survey, and the Rocky Mountain Association of Geologists dating back more than 30 years. For example, a 1976 publication by the Colorado Division of Water Resources states that the aquifer contains "troublesome amounts of . . . methane." A 1983 publication by the United States Geological Survey similarly states that "[m]ethane-rich gas commonly occurs in ground water in the Denver Basin, southern Weld County, Colorado." And a 2001 report by the Colorado Geological Survey discusses the methane potential of this formation and cites approximately 30 publications on this subject.

Laboratory analysis confirmed that the Markham and McClure wells contained biogenic methane typical of gas that is naturally found in the coals of the Laramie–Fox Hills Aquifer. This determination was based on a stable isotope analysis, which effectively "finger-printed" the gas as biogenic, as well as a gas composition analysis, which indicated that heavier hydrocarbons associated with thermogenic gas were absent. In addition, water samples from the wells were analyzed for benzene, toluene, ethylbenzene, and xylenes (BTEX), which are constituents of the hydrocarbons produced by oil and gas wells in the area. The absence of any BTEX compounds in these water samples provided additional evidence that oil and gas activity did not contaminate the Markham and McClure wells.

The COGCC has also reviewed the records for all oil and gas wells located within one-half mile of the Markham and McClure wells, which is more than double the typical hydraulic fracture length in Colorado. This review indicated that: all oil and gas wells near the Markham well were drilled and hydraulically fractured in 1991, except for two wells that were fractured in 2005 and 2006, respectively; and all oil and gas wells near the McClure well were drilled and hydraulically fractured in 2002, except for one well that was hydraulically fractured in 2005. The records do not reflect any pressure failures or other problems associated with these wells that would indicate a loss of fracture fluid or gas from the well bore into the surrounding geologic formations.

In support of its thesis that the Markham and McClure water wells were contaminated by oil and gas development, the *Gasland* website makes several arguments that merit a brief response. First, the website quotes Professor Anthony Ingraffea of Cornell University for the proposition that drilling and hydraulic fracturing could cause biogenic methane to migrate into aquifers under certain circumstances. However, Professor Ingraffea's statement does not suggest that these circumstances apply to the Markham and McClure wells, nor does it address the extensive scientific literature establishing that biogenic methane is naturally present in the aquifer in question. Second, the website quotes Weston Wilson, an Environmental Protection Agency employee, speculating that oil and gas operators in Weld County are withdrawing large amounts of groundwater and that these withdrawals are releasing biogenic methane. However, oil and gas companies in Weld County obtain most of their water from municipalities, which obtain such water from surface water sources such as the Colorado-Big Thompson and Windy

Gap projects. Finally, the website asserts that the water in the Markham and McClure wells deteriorated after drilling and hydraulic fracturing occurred nearby. However, COGCC records indicate little or no temporal relationship between the Markham and McClure complaints and nearby drilling and hydraulic fracturing activities, which occurred several years earlier and in most cases many years earlier.

The West Divide Creek Seeps

Gasland also addresses complaints about oil and gas activity in the West Divide Creek area of the Piceance Basin in Garfield County, though it again confuses issues related to biogenic gas with those related to thermogenic gas. The film focuses on two seeps that are in close geographic proximity but derive from different origins. One of the seeps occurs in a wetland on property owned by Lisa Bracken, who appears in the film; it contains biogenic methane. The other seep, which the COGCC terms the West Divide Creek gas seep, is about 1,500 feet to the south on property owned by a neighbor; it contains thermogenic methane caused by EnCana's failure to properly cement a natural gas well.

Gasland adopts the claim that the West Divide Creek gas seep was caused by hydraulic fracturing. After investigating the matter thoroughly in 2004, COGCC staff concluded the seep was caused by gas migrating up a gas well borehole that had not been properly cemented and in which the upper portion of the gas bearing Williams Fork Formation had not been isolated. On August 16, 2004, following a public hearing, the COGCC commissioners approved an enforcement order (Order 1V-276) that incorporated the staff's causation conclusions and assessed a substantial fine against the operator.

In investigating the West Divide gas seep, the COGCC determined that it contains thermogenic methane. The gas composition and stable isotope signature of the gas closely matched that of the gas being produced from the Williams Fork Formation. The gas from both the West Divide Creek seep and the Williams Fork Formation is composed primarily of methane, but it also contains ethane, propane, butane, pentane, and hexanes. In addition, BTEX compounds were detected in ground and surface water in the vicinity of the West Divide Creek seep, which indicates that the gas is related to oil and gas activities and not of biogenic origin.

In contrast, the laboratory results for the gas samples collected from the seep on Ms. Bracken's property have demonstrated that the gas is biogenic. The COGCC has collected nine gas samples on six different occasions during 2004, 2007, 2009, and 2010. With respect to each sample, the gas composition was found to be 100 percent methane, no heavier hydrocarbon compound was detected, and the stable isotope ratio indicated that the gas is biogenic. The COGCC has also collected six water samples on four different occasions during 2004, 2007, and 2009 and ten soil samples on multiple occasions during 2008 and 2009 from Ms. Bracken's property. BTEX compounds and/or other hydrocarbons associated with oil and gas operations were not detected in any of these samples. Based on these results, the COGCC has concluded that the gas seep on Ms. Bracken's property resulted from the fermentation of organic matter by methanogenic bacteria. This is not uncommon in wetland areas, such as those that exist along West Divide Creek.

Other Information

Oil and gas development is an industrial activity, and property owners sometimes complain that it has contaminated their water well. The COGCC investigates all such complaints and reports the results individually to the complainant and collectively to the Colorado Water Quality Control

Division. In some cases, the COGCC has found that the well contains thermogenic methane linked to oil and gas development. In most cases, however, the COGCC has found that contamination is not present or that the methane comes from biogenic sources and is not attributable to oil and gas production. The following excerpt from a report summarizing the COGCC's investigation following the contamination of the Ellsworth water well is illustrative:

> In response to concerns regarding the presence of methane gas in water wells completed in the Laramie/Fox Hills Aquifer, COGCC, Noble Energy, and Anadarko/Kerr McGee sampled a total of 28 water wells between March 25, 2009 and April 7, 2009 across an approximately 170 square mile area. Sample results show that these wells contained either no methane gas or biogenic (biological generated) methane gas. None of these wells, other than the Ellsworth water well, contained thermogenic methane gas. The sample results along with letters discussing the results were sent by COGCC staff to the 28 well owners [who had requested testing].

Nevertheless, it remains important to establish prudent regulations to ensure that other resources, such as groundwater, are protected. Producing oil and gas formations in much of Colorado, including the Denver-Julesburg and Piceance Basins, lie at depths of up to 8,000 feet below the ground surface, while the aquifers that sustain domestic water wells are generally less than 1,000 feet below the ground surface. COGCC regulations establish casing and cementing standards to ensure that gas being produced from 8,000 feet down does not leak into the shallower aquifers. These regulations require wells to be cased with steel pipe and the casing to be surrounded by cement to create a hydraulic seal within the annular space between the wall of the well bore and the steel pipe. In addition, a number of recent amendments to the COGCC regulations address concerns raised about hydraulic fracturing:

- Rule 205 requires operators to inventory chemicals, including fracturing fluids, and to provide this information upon request to the COGCC and certain health care professionals;
- Rule 317 requires cement bond logs to confirm that aquifers are protected;
- Rule 317B imposes mandatory setbacks and enhanced environmental precautions on oil and gas development occurring near public drinking water sources;
- Rule 341 requires well pressures to be monitored during hydraulic fracturing;
- Rule 608 mandates additional pressure testing and water well sampling for coalbed methane wells; and
- Rules 903 , 904 , and 906 impose enhanced requirements for pit permitting, lining, monitoring, and secondary containment to ensure that pit fluids, including hydraulic fracturing flowback, do not leak.

Finally, it should be understood that the COGCC Director, Dave Neslin, offered to speak with *Gasland's* producer, Josh Fox, on camera during the filming of the movie. Because the issues are technical and complex and arouse concerns in many people, Director Neslin asked that he be allowed to review any material from the interview that would be included in the final film. Unfortunately, Mr. Fox declined. Such a discussion might have prevented the inaccuracies noted above.

Hydraulic fracturing

From Wikipedia, the free encyclopedia

Contents

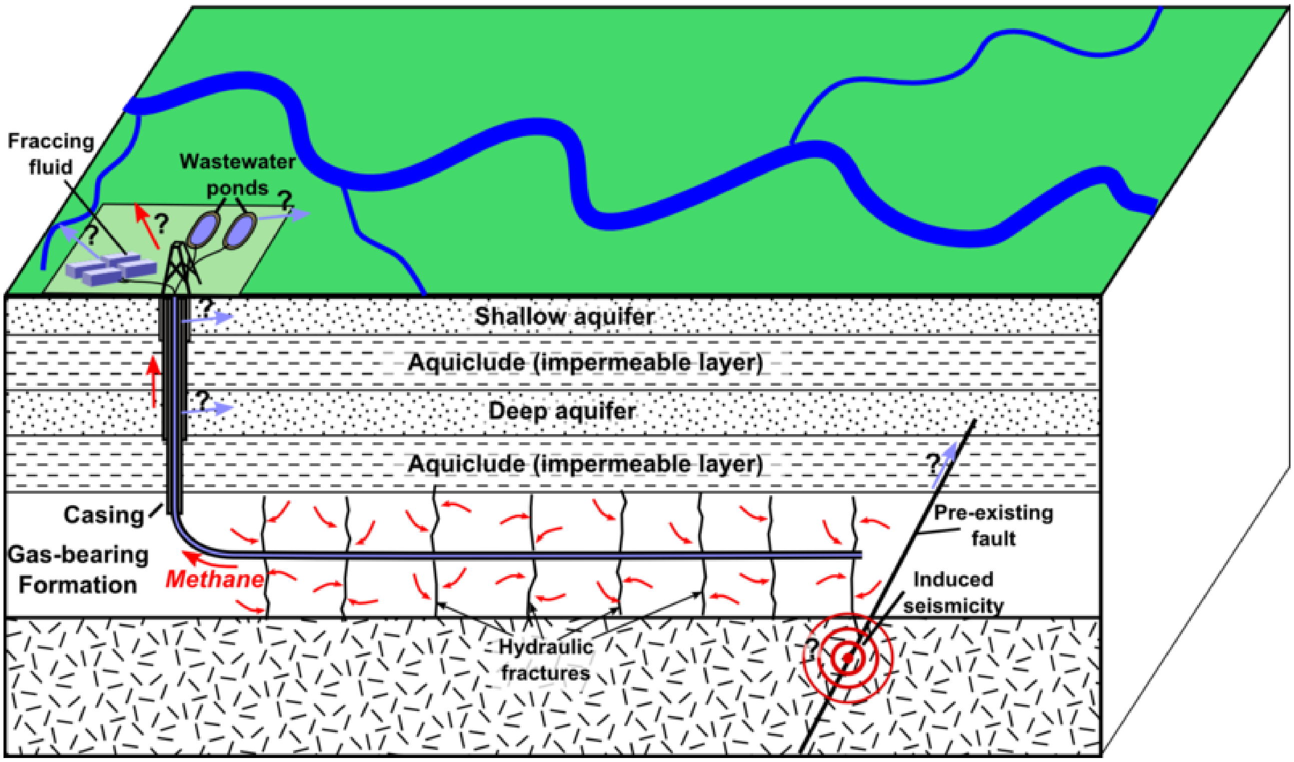
0.0 Introduction

Hydraulic fracturing	
Process type	Mechanical
Industrial sector(s)	Mining
Main technologies or sub-processes	Fluid pressure
Product(s)	Natural gas Petroleum
Inventor	Floyd Farris; J.B. Clark (Stanolind Oil and Gas Corporation)
Year of invention	1947

Hydraulic fracturing is the propagation of fractures in a rock layer by a pressurized fluid. Some hydraulic fractures form naturally—certain veins or dikes are examples—and can create conduits along which gas and petroleum from source rocks may migrate to reservoir rocks. **Induced hydraulic fracturing** or **hydrofracturing**, commonly known as **fracing**, **fraccing**, or **fracking**, is a technique used to release petroleum, natural gas (including shale gas, tight gas, and coal seam gas), or other substances for extraction.[1] This type of fracturing creates fractures from a wellbore drilled into reservoir rock formations. The first use of hydraulic fracturing was in 1947. However, it was only in 1998 that modern fracturing technology, referred to as horizontal slickwater fracturing, made possible the economical extraction of shale gas; this new technology was first used in the Barnett Shale in Texas.[1][2][3] The energy from the injection of a highly pressurized hydraulic fracturing fluid creates new channels in the rock, which can increase the extraction rates and ultimate recovery of hydrocarbons.

Proponents of hydraulic fracturing point to the economic benefits from vast amounts of formerly inaccessible hydrocarbons the process can extract.[4] Opponents point to potential environmental impacts, including contamination of ground water, risks to air quality, the migration of gases and hydraulic fracturing chemicals to the surface, surface contamination from spills and flowback and the health effects of these.[5] For these reasons hydraulic fracturing has come under scrutiny internationally, with some countries suspending or banning it.[6][7]

Schematic depiction of hydraulic fracturing for shale gas



1.0 Geology

Main article: Fracture (geology)

1.1 Mechanics

Fracturing in rocks at depth tends to be suppressed by the confining pressure, due to the load caused by the overlying rock strata. This is particularly so in the case of "tensile" (Mode 1) fractures, which require the walls of the fracture to move apart, working against this confining pressure. Hydraulic fracturing occurs when the effective stress is reduced sufficiently by an increase in the pressure of fluids within the rock, such that the minimum principal stress becomes tensile and exceeds the tensile strength of the material.[8][9] Fractures formed in this way will in the main be oriented in the plane perpendicular to the minimum principal stress and for this reason induced hydraulic fractures in wellbores are sometimes used to determine the orientation of stresses.[10] In natural examples, such as dikes or vein-filled fractures, the orientations can be used to infer past states of stress.[11]

1.2 Veins

Most vein systems are a result of repeated hydraulic fracturing during periods of relatively high pore fluid pressure. This is particularly noticeable in the case of "crack-seal" veins, where the vein material can be seen to have been added in a series of discrete fracturing events, with extra vein material deposited on each occasion.[12] One mechanism to demonstrate such examples of long-lasting repeated fracturing is the effects of seismic activity, in which the stress levels rise and fall episodically and large volumes of fluid may be expelled from fluid-filled fractures during earthquakes. This process is referred to as "seismic pumping".[13]

1.3 Dikes

High-level minor intrusions such as dikes propagate through the crust in the form of fluid-filled cracks, although in this case the fluid is magma. In sedimentary rocks with a significant water content the fluid at the propagating fracture tip will be steam.[14]

2.0 History

Fracturing as a method to stimulate shallow, hard rock oil wells dates back to the 1860s. It was applied by oil producers in the US states of Pennsylvania, New York, Kentucky, and West Virginia by using liquid and later also solidified nitroglycerin. Later, the same method was applied to water and gas wells. The idea to use acid as a nonexplosive fluid for well stimulation was introduced in the 1930s. Due to acid etching, fractures would not close completely and therefore productivity was enhanced. The same phenomenon was discovered with water injection and squeeze cementing operations.[15]

The relationship between well performance and treatment pressures was studied by Floyd Farris of Stanolind Oil and Gas Corporation. This study became a basis of the first hydraulic fracturing experiment, which was conducted in 1947 at the Hugoton gas field in Grant County of southwestern Kansas by Stanolind.[1][15] For the well treatment 1,000 US gallons (3,800 l; 830 imp gal) of gelled gasoline and sand from the Arkansas River was injected into the gas-producing limestone formation at 2,400 feet (730 m). The experiment was not very successful as deliverability of the well did not change appreciably. The process was further described by J.B. Clark of Stanolind in his paper published in 1948. A patent on this process was issued in 1949 and an exclusive license was granted to the Halliburton Oil Well Cementing Company. On

March 17, 1949, Halliburton performed the first two commercial hydraulic fracturing treatments in Stephens County, Oklahoma, and Archer County, Texas.[15] Since then, hydraulic fracturing has been used to stimulate approximately a million oil and gas wells.[16]

In the Soviet Union, the first hydraulic proppant fracturing was carried out in 1952. In Western Europe in 1977–1985, hydraulic fracturing was conducted at Rotliegend and Carboniferous gas-bearing sandstones in Germany, Netherlands onshore and offshore gas fields, and the United Kingdoms sector of the North Sea. Other countries in Europe and Northern Africa included Norway, the Soviet Union, Poland, Czechoslovakia, Yugoslavia, Hungary, Austria, France, Italy, Bulgaria, Romania, Turkey, Tunisia, and Algeria.[17]

Due to shale's high porosity and low permeability, technology research, development and demonstration were necessary before hydraulic fracturing could be commercially applied to shale gas deposits. In the 1970s the United States government initiated the Eastern Gas Shales Project, a set of dozens of public-private hydraulic fracturing pilot demonstration projects. During the same period, the Gas Research Institute, a gas industry research consortium, received approval for research and funding from the Federal Energy Regulatory Commission.[18] In 1977, the Department of Energy pioneered massive hydraulic fracturing in tight sandstone formations. In 1997, based on earlier techniques used by Union Pacific Resources, now part of Anadarko Petroleum Corporation, Mitchell Energy, now part of Devon Energy, developed the hydraulic fracturing technique known as "slickwater fracturing" which involves adding chemicals to water to increase the fluid flow, that made the shale gas extraction economical.[2][3][19]

3.0 Induced hydraulic fracturing

According to the United States Environmental Protection Agency (EPA) *hydraulic fracturing* is a process to stimulate a natural gas, oil, or geothermal energy well to maximize the extraction. The whole process is defined as including the acquisition of source water, well construction, well stimulation, and waste disposal.[20]

3.1 Uses

The technique of hydraulic fracturing is used to increase or restore the rate at which fluids, such as petroleum, water, or natural gas can be produced from subterranean natural reservoirs. Reservoirs are typically porous sandstones, limestones or dolomite rocks, but also include "unconventional reservoirs" such as shale rock or coal beds. Hydraulic fracturing enables the production of natural gas and oil from rock formations deep below the earth's surface (generally 5,000–20,000 feet (1,500–6,100 m)). At such depth, there may not be sufficient permeability or reservoir pressure to allow natural gas and oil to flow from the rock into the wellbore at economic rates. Thus, creating conductive fractures in the rock is pivotal to extract gas from shale reservoirs because of the extremely low natural permeability of shale, which is measured in the microdarcy to nanodarcy range.[21] Fractures provide a conductive path connecting a larger volume of the reservoir to the well. So-called "super fracing", which creates cracks deeper in the rock formation to release more oil and gas, will increase efficiency of hydraulic fracturing.[22] The yield for a typical shale gas well generally falls off sharply after the first year or two.[23]

While the main industrial use of hydraulic fracturing is in arousing production from oil and gas wells,[24][25][26] hydraulic fracturing is also applied:

- To stimulate groundwater wells[27]
- To precondition or induce rock to cave in mining[28]
- As a means of enhancing waste remediation processes, usually hydrocarbon waste or spills[29]
- To dispose of waste by injection into deep rock formations[30]
- As a method to measure the stress in the earth[31]
- For heat extraction to produce electricity in an enhanced geothermal systems[32]
- To increase injection rates for geologic sequestration of CO_2[33]

3.2 Method

A hydraulic fracture is formed by pumping the fracturing fluid into the wellbore at a rate sufficient to increase pressure downhole to exceed that of the fracture gradient (pressure gradient) of the rock.[34] The fracture gradient is defined as the pressure increase per unit of the depth due to its density and it is usually measured in pounds per square inch per foot or bars per meter. The rock cracks and the fracture fluid continues further into the rock, extending the crack still further, and so on. Operators typically try to maintain "fracture width", or slow its decline, following treatment by introducing into the injected fluid a proppant – a material such as grains of sand, ceramic, or other particulates, that prevent the fractures from closing when the injection is stopped and the pressure of the fluid is reduced. Consideration of proppant strengths and prevention of proppant failure becomes more important at greater depths where pressure and stresses on fractures are higher. The propped fracture is permeable enough to allow the flow of formation fluids to the well. Formation fluids include gas, oil, salt water, fresh water and fluids introduced to the formation during completion of the well during fracturing.[34]

During the process fracturing fluid leakoff, loss of fracturing fluid from the fracture channel into the surrounding permeable rock occurs. If not controlled properly, it can exceed 70% of the injected volume. This may result in formation matrix damage, adverse formation fluid interactions, or altered fracture geometry and thereby decreased production efficiency.[35]

The location of one or more fractures along the length of the borehole is strictly controlled by various methods that create or seal off holes in the side of the wellbore. Typically, hydraulic fracturing is performed in cased wellbores and the zones to be fractured are accessed by perforating the casing at those locations.[36]

Hydraulic-fracturing equipment used in oil and natural gas fields usually consists of a slurry blender, one or more high-pressure, high-volume fracturing pumps (typically powerful triplex or quintuplex pumps) and a monitoring unit. Associated equipment includes fracturing tanks, one or more units for storage and handling of proppant, high-pressure treating iron, a chemical additive unit (used to accurately monitor chemical addition), low-pressure flexible hoses, and many gauges and meters for flow rate, fluid density, and treating pressure.[37] Fracturing equipment operates over a range of pressures and injection rates, and can reach up to 100 megapascals (15,000 psi) and 265 litres per second (9.4 cu ft/s) (100 barrels per minute).[38]

3.3 Well types

A distinction can be made between conventional or low-volume hydraulic fracturing used to stimulate high-permeability reservoirs to frac a single well, and unconventional or high-volume hydraulic fracturing, used in the completion of tight gas and shale gas wells as unconventional wells are deeper and require higher pressures than conventional vertical wells.[39] In addition to hydraulic fracturing of vertical wells, it is also performed in horizontal wells. When done in already highly permeable reservoirs such as sandstone-based wells, the technique is known as "well stimulation".[26]

Horizontal drilling involves wellbores where the terminal drillhole is completed as a "lateral" that extends parallel with the rock layer containing the substance to be extracted. For example, laterals extend 1,500 to

5,000 feet (460 to 1,500 m) in the Barnett Shale basin in Texas, and up to 10,000 feet (3,000 m) in the Bakken formation in North Dakota. In contrast, a vertical well only accesses the thickness of the rock layer, typically 50–300 feet (15–91 m). Horizontal drilling also reduces surface disruptions as fewer wells are required to access a given volume of reservoir rock. Drilling usually induces damage to the pore space at the wellbore wall, reducing the permeability at and near the wellbore. This reduces flow into the borehole from the surrounding rock formation, and partially seals off the borehole from the surrounding rock. Hydraulic fracturing can be used to restore permeability.[40]

3.4 Fracturing fluids

Main articles: Proppants and fracking fluids and List of additives for hydraulic fracturing

High-pressure fracture fluid is injected into the wellbore, with the pressure above the fracture gradient of the rock. The two main purposes of fracturing fluid is to extend fractures and to carry proppant into the formation, the purpose of which is to stay there without damaging the formation or production of the well. Two methods of transporting the proppant in the fluid are used – high-rate and high-viscosity. High-viscosity fracturing tends to cause large dominant fractures, while high-rate (slickwater) fracturing causes small spread-out micro-fractures.[citation needed]

This fracture fluid contains water-soluble gelling agents (such as guar gum) which increase viscosity and efficiently deliver the proppant into the formation.[41]
The fluid injected into the rock is typically a slurry of water, proppants, and chemical additives.[42] Additionally, gels, foams, and compressed gases, including nitrogen, carbon dioxide and air can be injected. Typically, of the fracturing fluid 90% is water and 9.5% is sand with the chemicals accounting to about 0.5%.[34][43][44]

A proppant is a material that will keep an induced hydraulic fracture open, during or following a fracturing treatment, and can be gel, foam, or slickwater-based. Fluids make tradeoffs in such material properties as viscosity, where more viscous fluids can carry more concentrated proppant; the energy or pressure demands to maintain a certain flux pump rate (flow velocity) that will conduct the proppant appropriately; pH, various rheological factors, among others. Types of proppant include silica sand, resin-coated sand, and man-made ceramics. These vary depending on the type of permeability or grain strength needed. The most commonly used proppant is silica sand, though proppants of uniform size and shape, such as a ceramic proppant, is believed to be more effective. Due to a higher porosity within the fracture, a greater amount of oil and natural gas is liberated.[45]

The fracturing fluid varies in composition depending on the type of fracturing used, the conditions of the specific well being fractured, and the water characteristics. A typical fracture treatment uses between 3 and 12 additive chemicals.[34] Although there may be unconventional fracturing fluids, the typical used chemical additives are:

- Acids—hydrochloric acid (usually 28%-5%), or acetic acid is used in the pre-fracturing stage for cleaning the perforations and initiating fissure in the near-wellbore rock.[44]
- Sodium chloride (salt)—delays breakdown of the gel polymer chains.[44]
- Polyacrylamide and other friction reducers—minimizes the friction between fluid and pipe, thus allowing the pumps to pump at a higher rate without having greater pressure on the surface.[44] Polyacrylamide are good suspension agents ensuring the proppant does not fall out.
- Ethylene glycol—prevents formation of scale deposits in the pipe.[44]
- Borate salts—used for maintaining fluid viscosity during the temperature increase.[44]
- Sodium and potassium carbonates—used for maintaining effectiveness of crosslinkers.[44]
- Glutaraldehyde—used as disinfectant of the water (bacteria elimination).[44]
- Guar gum and other water-soluble gelling agents—increases viscosity of the fracturing fluid to deliver more efficiently the proppant into the formation.[41][44]
- Citric acid—used for corrosion prevention.
- Isopropanol—increases the viscosity of the fracture fluid.[44]

The most common chemical used for hydraulic fracturing in the United States in 2005–2009 was methanol, while some other most widely used chemicals were isopropyl alcohol, 2-butoxyethanol, and ethylene glycol.[46]

Typical fluid types are:

- Conventional linear gels. These gels are cellulose derivatives (carboxymethyl cellulose, hydroxyethyl cellulose, carboxymethyl hydroxyethyl cellulose, hydroxypropyl cellulose, methyl hydroxyl ethyl cellulose), guar or its derivatives (hydroxypropyl guar, carboxymethyl hydroxypropyl guar) based, with other chemicals providing the necessary chemistry for the desired results.
- Borate-crosslinked fluids. These are guar-based fluids cross-linked with boron ions (from aqueous borax/boric acid solution). These gels have higher viscosity at pH 9 onwards and are used to carry

proppants. After the fracturing job the pH is reduced to 3–4 so that the cross-links are broken and the gel is less viscous and can be pumped out.

- Organometallic-crosslinked fluids zirconium, chromium, antimony, titanium salts are known to crosslink the guar based gels. The crosslinking mechanism is not reversible. So once the proppant is pumped down along with the cross-linked gel, the fracturing part is done. The gels are broken down with appropriate breakers.[41]
- Aluminium phosphate-ester oil gels. Aluminium phosphate and ester oils are slurried to form cross-linked gel. These are one of the first known gelling systems.

For slickwater it is common to include sweeps or a reduction in the proppant concentration temporarily to ensure the well is not overwhelmed with proppant causing a screen-off.[47] As the fracturing process proceeds, viscosity reducing agents such as oxidizers and enzyme breakers are sometimes then added to the fracturing fluid to deactivate the gelling agents and encourage flowback.[41] The oxidizer reacts with the gel to break it down, reducing the fluid's viscosity and ensuring that no proppant is pulled from the formation. An enzyme acts as a catalyst for the breaking down of the gel. Sometimes pH modifiers are used to break down the crosslink at the end of a hydraulic fracturing job, since many require a pH buffer system to stay viscous.[47] At the end of the job the well is commonly flushed with water (sometimes blended with a friction reducing chemical) under pressure. Injected fluid is to some degree recovered and is managed by several methods, such as underground injection control, treatment and discharge, recycling, or temporary storage in pits or containers while new technology is being continually being developed and improved to better handle waste water and improve re-usability.[34]

3.5 Fracture monitoring

Measurements of the pressure and rate during the growth of a hydraulic fracture, as well as knowing the properties of the fluid and proppant being injected into the well provides the most common and simplest method of monitoring a hydraulic fracture treatment. This data, along with knowledge of the underground geology can be used to model information such as length, width and conductivity of a propped fracture.[34] Injection of radioactive tracers, along with the other substances in hydraulic-fracturing fluid, is sometimes used to determine the injection profile and location of fractures created by hydraulic fracturing.[48] The radiotracer is chosen to have the readily detectable radiation, appropriate chemical properties, and a half life and toxicity level that will minimize initial and residual contamination.[49] Radioactive isotopes chemically bonded to glass (sand) and/or resin beads may also be injected to track fractures.[50] For example, plastic pellets coated with 10 GBq of Ag-110mm may be added to the proppant or sand may be labelled with Ir-192 so that the proppant's progress can be monitored.[49] Radiotracers such as Tc-99m and I-131 are also used to measure flow rates.[49] The Nuclear Regulatory Commission publishes guidelines which list a wide range of radioactive materials in solid, liquid and gaseous forms that may be used as tracers and limit the amount that may be used per injection and per well of each radionuclide.[50]

For more advanced applications, microseismic monitoring is sometimes used to estimate the size and orientation of hydraulically induced fractures. Microseismic activity is measured by placing an array of geophones in a nearby wellbore. By mapping the location of any small seismic events associated with the growing hydraulic fracture, the approximate geometry of the fracture is inferred. Tiltmeter arrays, deployed on the surface or down a well, provide another technology for monitoring the strains produced by hydraulic fracturing.[51]

3.6 Horizontal completions

Since the early 2000s, advances in drilling and completion technology have made drilling horizontal wellbores much more economical. Horizontal wellbores allow for far greater exposure to a formation than a conventional vertical wellbore. This is particularly useful in shale formations which do not have sufficient permeability to produce economically with a vertical well. Such wells when drilled onshore are now usually hydraulically fractured in a number of stages, especially in North America. The type of wellbore completion used will affect how many times the formation is fractured, and at what locations along the horizontal section of the wellbore.[52]

In North America, shale reservoirs such as the Bakken, Barnett, Montney, Haynesville, Marcellus, and most recently the Eagle Ford, Niobrara and Utica shales are drilled, completed and fractured using this method.[*citation needed*] The method by which the fractures are placed along the wellbore is most commonly achieved by one of two methods, known as "plug and perf" and "sliding sleeve".[53]

The wellbore for a plug and perf job is generally composed of standard joints of steel casing, either cemented or uncemented, which is set in place at the conclusion of the drilling process. Once the drilling rig has been removed, a wireline truck is used to perforate near the end of the well, following which a fracturing job is pumped (commonly called a stage). Once the stage is finished, the wireline truck will set a plug in the well to temporarily seal off that section, and then perforate the next section of the wellbore.

Another stage is then pumped, and the process is repeated as necessary along the entire length of the horizontal part of the wellbore.[54]

The wellbore for the sliding sleeve technique is different in that the sliding sleeves are included at set spacings in the steel casing at the time it is set in place. The sliding sleeves are usually all closed at this time. When the well is ready to be fractured, using one of several activation techniques, the bottom sliding sleeve is opened and the first stage gets pumped. Once finished, the next sleeve is opened which concurrently isolates the first stage, and the process repeats. For the sliding sleeve method, wireline is usually not required.[*citation needed*]

These completion techniques may allow for more than 30 stages to be pumped into the horizontal section of a single well if required, which is far more than would typically be pumped into a vertical well.[55]

4.0 Economic impacts

See also: Shale gas

Hydraulic fracturing has been seen as one of the key methods of extracting unconventional oil and gas resources. According to the International Energy Agency, the remaining technically recoverable resources of shale gas are estimated to amount to 208 trillion cubic metres (7.3 quadrillion cubic feet), tight gas to 76 trillion cubic metres (2.7 quadrillion cubic feet), and coalbed methane to 47 trillion cubic metres (1.7 quadrillion cubic feet). As a rule, formations of these resources have lower permeability than conventional gas formations. Therefore, depending on the geological characteristics of the formation, specific technologies (such as hydraulic fracturing) are required. Although there are also other methods to extract these resources, such as conventional drilling or horizontal drilling, hydraulic fracturing is one of the key methods making their extraction economically viable. The multi-stage fracturing technique has facilitated the development of shale gas and light tight oil production in the United States and is believed to do so in the other countries with unconventional hydrocarbon resources. Significance of the extraction of unconventional hydrocarbons lies also in the fact that these resources are less concentrated than conventional oil and gas resources.[4]

Hydraulic fracturing will account for nearly 70% of natural gas development in the future.[56] Hydraulic fracturing and horizontal drilling apply the latest technologies and make it commercially viable to recover shale gas and oil. In the United States, 45% of domestic natural gas production and 17% of oil production would be lost within 5 years without usage of hydraulic fracturing.[57]

Development of shale resources supported 600,000 jobs in 2010.[58] Affordable, domestic natural gas is essential to rejuvenating the chemical, manufacturing, and steel industries. The American Chemistry Council determined that a 25% increase in the supply of ethane (a liquid derived from shale gas) could add over 400,000 jobs across the economy, provide over $4.4 billion annually in federal, state, and local tax revenue, and spur $16.2 billion in capital investment by the chemical industry.[59]

They also note that the relatively low price of ethane would give U.S. manufacturers an essential advantage over many global competitors. Similarly, the National Association of Manufacturers estimated that high recovery of shale gas and lower natural gas prices will help U.S. manufacturers employ 1,000,000 workers by 2025 while lower feedstock and energy costs could help them reduce natural gas expenditures by as much as 11.6 billion by 2025.[60] America's Natural Gas Association (ANGA) estimates that lower gas prices will add an additional $926 of disposable household income annually between 2012 and 2015, and that the amount could increase to $2,000 by 2035.[61]

In December 2012 the Council on Foreign Relations argued that the reduction of gas prices could have a major impact on Russia. 60% of Russia's federal revenues come from energy exports and any reduction in income from gas would be catastrophic for Russia. Economic necessity and looming bankruptcy could one day force political reform on Russia. The article suggests that Russia has therefore financed environmental groups to oppose unconventional gas extraction methods like hydraulic fracturing, because there aren't normally protests in these countries. Because of large, country wide protests, Bulgaria and Czech Republic have banned this technology.[62]

5.0 Environmental impact

Main article: Environmental impact of hydraulic fracturing

See also: Environmental impact of hydraulic fracturing in the United States

Hydraulic fracturing has raised environmental concerns and is challenging the adequacy of existing regulatory regimes.[63] These concerns have included ground water contamination, risks to air quality, migration of gases and hydraulic fracturing chemicals to the surface, mishandling of waste, and the health effects of all these, as well as its contribution to raised atmospheric CO_2 levels by enabling the extraction of previously-sequestered hydrocarbons.[5][34][46] Because hydraulic fracturing originated in the United States,[64] its history is more extensive there than in other regions. Most environmental impact studies have therefore taken place there.

5.1 Research issues

Several organizations, researchers, and media outlets have reported difficulty in conducting and reporting the results of studies on hydraulic fracturing due to industry[65][66][67] and governmental pressure, and expressed concern over possible censoring of environmental reports.[65][68][69] Researchers have recommended requiring disclosure of all hydraulic fracturing fluids, testing animals raised near fracturing sites, and closer monitoring of environmental samples.[70] After court cases concerning contamination from hydraulic fracturing are settled, the documents are sealed. The American Petroleum Institute deny that this practice has hidden problems with gas drilling, while others believe it has and could lead to unnecessary risks to public safety and health.[71]

5.2 Air

See also: Environmental impact of hydraulic fracturing in the United States#Air emissions

The air emissions from hydraulic fracturing are related to methane leaks originating from wells, and emissions from the diesel or natural gas powered equipment such as compressors, drilling rigs, pumps etc.[34] Also transportation of necessary water volume for hydraulic fracturing, if done by trucks, can cause high volumes of air emissions, especially particulate matter emissions.[72]

Shale gas produced by hydraulic fracturing causes higher well-to-burner emissions than conventional gas. This is mainly due to the gas released during completing wells as some gas returns to the surface, together with the fracturing fluids. Depending on their treatment, the well-to-burner emissions are 3.5%–12% higher than for conventional gas.[63] According to a study conducted by professor Robert W. Howarth *et al.* of Cornell University, "3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well." The study claims that this represents a 30–100% increase over conventional gas production.[73] Methane gradually breaks down in the atmosphere, forming carbon dioxide, which contributes to greenhouse gasses more than coal or oil for timescales of less than fifty years.[73][74] Howarth's colleagues at Cornell and others have criticized the study's design,[75][76] however several other studies have also found higher emissions from shale-gas production than from conventional gas production.[77][78][79][80] Howarth et al. have responded, "The latest EPA estimate for methane emissions from shale gas falls within the range of our estimates but not those of Cathles et al, which are substantially lower."[81]

In some areas, elevated air levels of harmful substances have coincided with elevated reports of health problems among the local populations. In DISH, Texas, elevated substance levels were detected and traced to hydraulic fracturing compressor stations,[82] and people living near shale gas drilling sites complained of health problems;[83] though a causal relationship to hydraulic fracturing was not established.[83]

5.3 Water

This section should be summarized and a link to Environmental impact of hydraulic fracturing provided by using the main template per the guidance in Wikipedia:Summary style. *(December 2012)*

5.3.1 Consumption

The large volumes of water required have raised concerns about hydraulic fracturing in arid areas, such as Karoo in South Africa.[64] During periods of low stream flow it may affect water supplies for municipalities and industries such as power generation, as well as recreation and aquatic life. It may also require water overland piping from distant sources.[84]

Hydraulic fracturing uses between 1.2 and 3.5 million US gallons (4.5 and 13 Ml) of water per well, with large projects using up to 5 million US gallons (19 Ml). Additional water is used when wells are refractured; this may be done several times.[41][85] An average well requires 3 to 8 million US gallons (11,000 to 30,000 m^3) of water over its lifetime.[34][84][85][86] Using the case of the Marcellus Shale as an example, as of 2008 hydraulic fracturing accounted for 650 million US gallons per year (2,500,000 m^3/a) or less than 0.8% of annual water use in the area overlying the Marcellus Shale.[84][87] The annual number of well permits, however, increased by a factor of five[88] and the number of well starts increased by a factor of over 17 from 2008 to 2011.[89] According to the Oxford Institute for Energy Studies, greater volumes of fracturing fluids are required in Europe, where the shale depths average 1.5 times greater than in the U.S.[90] To minimize water consumption, recycling is one possible option.[63]

5.3.2 Injected fluid

See also: List of additives for hydraulic fracturing

There are concerns about possible contamination by hydraulic fracturing fluid both as it is injected under high pressure into the ground and as it returns to the surface.[91] To mitigate the impact of hydraulic fracturing to groundwater, the well and ideally the shale formation itself should remain hydraulically isolated from other geological formations, especially freshwater aquifers.[63] In the United States hydraulic fracturing areas at least 36 cases of groundwater contamination due to hydraulic fracturing have been suspected and in several cases EPA has determined that hydraulic fracturing was likely the source of the contamination.[71][92][93][94][95][96]

While some of the chemicals used in hydraulic fracturing are common and generally harmless, some are known carcinogens at high enough doses.[46] A report prepared for House Democratic members Henry Waxman, Edward Markey and Diana DeGette stated that out of 2,500 hydraulic fracturing products, "more than 650 of these products contained chemicals that are known or possible human carcinogens, regulated under the Safe Drinking Water Act, or listed as hazardous air pollutants".[46] The report also shows that between 2005 and 2009, 279 products had at least one component listed as "proprietary" or "trade secret" on their Occupational Safety and Health Administration (OSHA) required material safety data sheet (MSDS). The MSDS is a list of chemical components in the products of chemical manufacturers, and according to OSHA, a manufacturer may withhold information designated as "proprietary" from this sheet. When asked to reveal the proprietary components, most companies participating in the investigation were unable to do so, leading the committee to surmise these "companies are injecting fluids containing unknown chemicals about which they may have limited understanding of the potential risks posed to human health and the environment".[46] Without knowing the identity of the proprietary components, regulators cannot test for their presence. This prevents government regulators from establishing baseline levels of the substances prior to hydraulic fracturing and documenting changes in these levels, thereby making it more difficult to prove that hydraulic fracturing is contaminating the environment with these substances.[97]

Another 2011 study identified 632 chemicals used in natural gas operations. Only 353 of these are well-described in the scientific literature. The study indicated possible long-term health effects that might not appear immediately. The study recommended full disclosure of all products used, along with extensive air and water monitoring near natural gas operations; it also recommended that hydraulic fracturing's exemption from regulation under the US Safe Drinking Water Act be rescinded.[98]

5.3.3 Flowback

As the fracturing fluid flows back through the well, it consists of spent fluids and may contain dissolved constituents such as minerals and brine waters. It may account for about 30–70% of the original fracture fluid volume. In addition, natural formation waters may flow to the well and need treatment. These fluids, commonly known as flowback, produced water, or wastewater, are managed by underground injection, wastewater treatment and discharge, or recycling to fracture future wells.[99] Hydraulic fracturing can concentrate levels of uranium, radium, radon, and thorium in flowback. [100]. Treatment of produced waters may be feasible through either self-contained systems at well sites or fields or through municipal waste water treatment plants or commercial treatment facilities.[99] However, the quantity of waste water needing treatment and the improper configuration of sewage plants have become an issue in some regions of the United States. Much of the wastewater from hydraulic fracturing operations is processed by public sewage treatment plants, which are not equipped to remove radioactive material and are not required to test for it.[101] More problematic may be the high levels of Bromide released into the rivers. The Bromide in the water combines with chlorine, which is used to disinfect drinking water at water treatment plants, and forms trihalomethanes (THMs).[102]

5.3.4 Methane

Groundwater methane contamination is also a concern as it has adverse impact on water quality and in extreme cases may lead to potential explosion.[103][104] In 2006, over 7 million cubic feet (200,000 m^3) of methane were released from a blown gas well in Clark, Wyoming and shallow groundwater was found to be contaminated.[105] However, methane contamination is not always caused by hydraulic fracturing. Drilling for ordinary drinking water wells can also cause methane release. Some studies make use of tests that can distinguish between the deep thermogenic methane released during gas/oil drilling, and the shallower biogenic methane that can be released during water-well drilling. While both forms of methane result from decomposition, thermogenic methane results from geothermal assistance deeper underground.[106][107]

According to the 2011 study of the MIT Energy Initiative, "there is evidence of natural gas (methane) migration into freshwater zones in some areas, most likely as a result of substandard well completion practices i.e. poor quality cementing job or bad casing, by a few operators."[108] 2011 studies by the Colorado School of Public Health and Duke University also pointed to methane contamination stemming from hydraulic fracturing or its surrounding process.[103][107] A study by Cabot Oil and Gas examined the Duke study using a larger sample size, found that methane concentrations were related to topography, with the highest readings found in low-lying areas, rather than related to distance from gas production areas. Using a more precise isotopic analysis, they showed that the methane found in the water wells came from both the Marcellus Shale (Middle Devonian) where hydraulic fracturing occurred, and from the shallower Upper Devonian formations.[106]

5.3.5 Radioactivity

See also: Radionuclides associated with hydraulic fracturing

A study examining a number of fracking sites in Pennsylvania and Virginia by Pennsylvania State University, found that water that flows back from gas wells after hydraulic fracturing contains high levels of radium.[109] Recycling this wastewater has been proposed as a partial solution, but this approach has limitations.[110] *The New York Times* has reported radium in wastewater from natural gas wells is released into Pennsylvania rivers,[104] and has compiled a map of these wells and their wastewater contamination levels,[111] and stated that some EPA reports were never made public. The *Times'* reporting on the issue has come under some criticism.[112][113]

5.3.6 Seismicity

Hydraulic fracturing causes induced seismicity called microseismic events or microearthquakes. The magnitude of these events is usually too small to be detected at the surface, although the biggest micro-earthquakes may have the magnitude of about -1.6 (M_w). The injection of waste water from gas operations, including from hydraulic fracturing, into saltwater disposal wells may cause bigger low-magnitude tremors, being registered up to 3.3 (M_w).[114]

The United States Geological Survey (USGS) has reported earthquakes induced by human measures, including hydraulic fracturing and hydraulic fracturing waste disposal wells, in several locations. According to the USGS only a small fraction of roughly 40,000 waste fluid disposal wells for oil and gas operations have induced earthquakes that are large enough to be of concern to the public.[115] Although the magnitudes of these quakes has been small, the USGS says that there is no guarantee that larger quakes will not occur.[116] In addition, the frequency of the quakes has been increasing. In 2009, there were 50 earthquakes greater than magnitude-3.0 in the area spanning Alabama and Montana, and there were 87 quakes in 2010. In 2011 there were 134 earthquakes in the same area, a sixfold increase over 20th century levels.[117] There are also concerns that quakes may damage underground gas, oil, and water lines and wells that were not designed to withstand earthquakes.[116][118]

A British Columbia Oil and Gas Commission investigation concluded that a series of 38 earthquakes (magnitudes ranging from 2.2 to 3.8 on the Richter scale) occurring in the Horn River Basin area between 2009 and 2011 were caused by fluid injection during hydraulic fracturing in proximity to pre-existing faults.[119] A report in the UK also concluded that hydraulic fracturing was the likely cause of some small tremors that occurred during shale gas drilling.[120][121][122]

Several earthquakes occurring throughout 2011, including a 4.0 magnitude quake on New Year's Eve that hit Youngstown, Ohio, are likely linked to a disposal of hydraulic fracturing wastewater, according to seismologists at Columbia University.[123] A similar series of small earthquakes occurred in 2012 in Texas. Earthquakes are not common occurrences in either area. Disposal and injection wells are regulated under the Safe Drinking Water Act and UIC laws.[124]

6.0 Health impact

Concern has been expressed over the possible long and short term health effects of air and water contamination and radiation exposure by gas production.[125][126][100] A study on the effect of gas drilling, including hydraulic fracturing, published by the Cornell University College of Veterinary Medicine, concluded that exposure to gas drilling operations was strongly implicated in serious health effects on humans and animals.[127] As of May 2012, the United States Institute of Medicine and United States National Research Council were preparing to review the potential human and environmental risks of hydraulic fracturing.[128][129]

In the United States the Occupational Safety and Health Administration (OSHA) and the National Institute for Occupational Safety and Health (NIOSH) have released a hazard alert based on data collected by NIOSH that workers may be exposed to dust with high levels of respirable crystalline silica (silica dioxide) during hydraulic fracturing.[130] NIOSH notified company representatives of these findings and provided reports with recommendations to control exposure to crystalline silica and recommend that all hydraulic fracturing sites evaluate their operations to determine the potential for worker exposure to crystalline silica and implement controls as necessary to protect workers.[131]

7.0 Public debate

7.1 Politics and public policy

To control the hydraulic fracturing industry, some governments are developing legislation and some municipalities are developing local zoning limitations.[132] In 2011, France became the first nation to ban hydraulic fracturing.[6][7] Some other countries have placed a temporary moratorium on the practice. The US has the longest history with hydraulic fracturing, so its approaches to hydraulic fracturing may be modeled by other countries.[64]

The considerable opposition against hydraulic fracturing activities in local townships has led companies to adopt a variety of public relations measures to assuage fears about hydraulic fracturing, including the admitted use of "military tactics to counter drilling opponents". At a conference where public relations measures were discussed, a senior executive at Anadarko Petroleum was recorded on tape saying, "Download the US Army / Marine Corps Counterinsurgency Manual, because we are dealing with an insurgency", while referring to hydraulic fracturing opponents. Matt Pitzarella, spokesman for Range Resources also told other conference attendees that Range employed psychological warfare operations veterans. According to Pitzarella, the experience learned in the Middle East has been valuable to Range Resources in Pennsylvania, when dealing with emotionally charged township meetings and advising townships on zoning and local ordinances dealing with hydraulic fracturing.[133][134]

7.2 Media coverage

Josh Fox's 2010 film *Gasland* became a center of opposition to hydraulic fracturing of shale. The movie presented problems with ground water contamination near well sites in Pennsylvania, Wyoming, and Colorado.[135] *Energy in Depth*, an oil and gas industry lobbying group, called the film's facts into question.[136] In response, a rebuttal of *Energy in Depth*'s claims of inaccuracy was posted on *Gasland's* website.[137] The Director of the Colorado Oil and Gas Conservation Commission (COGCC) offered to be interviewed as part of the film if he could review what was included from the interview in the final film but Fox declined the offer. The COGCC took issue with what it called "several errors" in the film after its production.[138] The Independent Petroleum Association of America later produced its own documentary, *Truthland*.[139] Exxon Mobil, Chevron Corporation and ConocoPhillips also aired advertisements during 2011 and 2012 that describe the economic and environmental benefits of natural gas and argue hydraulic fracturing is safe.[139] The film *Promised Land*, starring Matt Damon, takes on hydraulic fracturing.[140] The gas industry has made plans to counter the film's criticisms of hydraulic fracturing with informational flyers, and Twitter and Facebook posts.[139]

One *New York Times* report claimed that an early draft of a 2004 EPA study discussed "possible evidence" of aquifer contamination but the final report omitted that mention.[65] Some have criticized the narrowing of EPA studies, including the EPA study on hydraulic fracturing's impact on drinking water to be released in late 2014,[141] such that hydrocarbon extraction processes not unique to hydraulic fracturing, such as drilling, casing, and above ground impacts, are considered beyond scope.[66][68][142][143][144]

8.0 See also

- Directional drilling
- Environmental concerns with electricity generation
- Environmental impact of petroleum
- Environmental impact of the oil shale industry
- ExxonMobil Electrofrac
- Hydraulic fracturing by country
- Hydraulic fracturing in the United States
- Natural gas
- Shale gas

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10.0 External links

This article's **use of external links may not follow Wikipedia's policies or guidelines**. Please improve this article by removing excessive or inappropriate external links, and converting useful links where appropriate into footnote references. *(May 2012)*

Wikinews has related news: ***Disposal of fracking wastewater poses potential environmental problems***

- Natural Gas Extraction—Hydraulic Fracturing (EPA website)
- EPA's Draft Hydraulic Fracturing Study Plan
- FracFocus Site indicating chemical composition of fracking fluid of individual wells
- FracTracker.org: Maps, data, and articles from news, government, industry, and academic sources.
- Fracking collected news and commentary at *ProPublica*
- Hydraulic Fracturing at Earthworks
- Hydraulic fracturing illustration on *ProPublica*
- 60 Minutes Report on Hydraulic Fracturing]
- Shale gas and fracking collected news and commentary at *The Guardian*

United States Environmental Protection Agency

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Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources

PROGRESS REPORT

United States Environmental Protection Agency
Office of Research and Development

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Washington, DC

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Table of Contents

Table of Contents

List of Tables

List of Tables

List of Tables

List of Figures

List of Figures

List of Acronyms and Abbreviations

ADQ	Audit of data quality
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
Br-DBP	Brominated disinfection byproduct
BTEX	Benzene, toluene, ethylbenzene, and xylene
CASRN	Chemical Abstracts Service Registration Number
CBI	Confidential business information
CBM	Coalbed methane
COGCC	Colorado Oil and Gas Conservation Commission
CWT	Centralized waste treatment facility
DBP	Disinfection byproduct
DSSTox	Distributed Structure-Searchable Toxicity Database Network
FORTRAN	Formula translation
GIS	Geographic information system
GWPC	Ground Water Protection Council
HAA	Haloacetic acid
HSPF	Hydrologic Simulation Program FORTRAN
IRIS	Integrated Risk Information System
LBNL	Lawrence Berkeley National Laboratory
LOAEL	Lowest observed adverse effect levels
MCL	Maximum contaminant level
MGD	Million gallons per day
MSDS	Material Safety Data Sheet
NAS	National Academy of Sciences
NDIC	North Dakota Industrial Commission
NEMS	National Energy Modeling System
NOM	Naturally occurring organic matter
NPDES	National Pollutant Discharge Elimination System
NRC	National Response Center
NYSDEC	New York State Department of Environmental Conservation
PADEP	Pennsylvania Department of Environmental Protection
POTW	Publicly owned treatment work
PPRTV	Provisional Peer-Reviewed Toxicity Value
PWS	Public water systems
QA	Quality assurance

List of Acronyms and Abbreviations

QAPP	Quality assurance project plan
QC	Quality control
RRC	Railroad Commission of Texas
SDWA	Safe Drinking Water Act
SOP	Standard operating procedure
SRB	Susquehanna River Basin
SRBC	Susquehanna River Basin Commission
SWAT	Soil and Water Assessment Tool
TDS	Total dissolved solids
THM	Trihalomethane
TOPKAT	Toxicity Prediction by Komputer Assisted Technology
TOUGH	Transport of Unsaturated Groundwater and Heat
TSA	Technical systems audit
TSCA	Toxic Substances Control Act
UCRB	Upper Colorado River Basin
UIC	Underground injection control
US EIA	US Energy Information Administration
US EPA	US Environmental Protection Agency
US FWS	US Fish and Wildlife Service
US GAO	US Government Accountability Office
US OMB	US Office of Management and Budget
USCB	US Census Bureau
USDA	US Department of Agriculture
USGS	US Geological Survey
USHR	US House of Representatives
WWTF	Wastewater treatment facility

Executive Summary

Natural gas plays a key role in our nation's clean energy future. The United States has vast reserves of natural gas that are commercially viable as a result of advances in horizontal drilling and hydraulic fracturing technologies, which enable greater access to gas in rock formations deep underground. These advances have spurred a significant increase in the production of both natural gas and oil across the country.

Responsible development of America's oil and gas resources offers important economic, energy security, and environmental benefits. However, as the use of hydraulic fracturing has increased, so have concerns about its potential human health and environmental impacts, especially for drinking water. In response to public concern, the US House of Representatives requested that the US Environmental Protection Agency (EPA) conduct scientific research to examine the relationship between hydraulic fracturing and drinking water resources (USHR, 2009).

In 2011, the EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources.* The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, if any, and to identify the driving factors that may affect the severity and frequency of such impacts. Scientists are focusing primarily on hydraulic fracturing of shale formations to extract natural gas, with some study of other oil- and gas-producing formations, including tight sands, and coalbeds. The EPA has designed the scope of the research around five stages of the hydraulic fracturing water cycle. Each stage of the cycle is associated with a primary research question:

- Water acquisition: What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- Chemical mixing: What are the possible impacts of hydraulic fracturing fluid surface spills on or near well pads 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 flowback and produced water (collectively referred to as "hydraulic fracturing wastewater") surface spills on or near well pads on drinking water resources?
- Wastewater treatment and waste disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewater on drinking water resources?

This report describes 18 research projects underway to answer these research questions and presents the progress made as of September 2012 for each of the projects. Information presented as part of this report cannot be used to draw conclusions about potential impacts to drinking water resources from hydraulic fracturing. The research projects are organized according to five different types of research activities: analysis of existing data, scenario evaluations, laboratory studies, toxicity assessments, and case studies.

Analysis of Existing Data

Data from multiple sources have been obtained for review and analysis. Many of the data come directly from the oil and gas industry and states with high levels of oil and gas activity. Information on the chemicals and practices used in hydraulic fracturing has been collected from nine companies that hydraulically fractured a total of 24,925 wells between September 2009 and October 2010. Additional data on chemicals and water use for hydraulic fracturing are being pulled from over 12,000 well-specific chemical disclosures in FracFocus, a national hydraulic fracturing chemical registry operated by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. Well construction and hydraulic fracturing records provided by well operators are being reviewed for 333 oil and gas wells across the United States; data within these records are being scrutinized to assess the effectiveness of current well construction practices at containing gases and liquids before, during, and after hydraulic fracturing.

Data on causes and volumes of spills of hydraulic fracturing fluids and wastewater are being collected and reviewed from state spill databases in Colorado, New Mexico, and Pennsylvania. Similar information is being collected from the National Response Center national database of oil and chemical spills.

In addition, the EPA is reviewing scientific literature relevant to the research questions posed in this study. A *Federal Register* notice was published on November 9, 2012, requesting relevant, peer-reviewed data and published reports, including information on advances in industry practices and technologies. This body of literature will be synthesized with results from the other research projects to create a report of results.

Scenario Evaluations

Computer models are being used to identify conditions that may lead to impacts on drinking water resources from hydraulic fracturing. The EPA has identified hypothetical, but realistic, scenarios pertaining to the water acquisition, well injection, and wastewater treatment and waste disposal stages of the water cycle. Potential impacts to drinking water sources from withdrawing large volumes of water in semi-arid and humid river basins—the Upper Colorado River Basin in the west and the Susquehanna River Basin in the east—are being compared and assessed.

Additionally, complex computer models are being used to explore the possibility of subsurface gas and fluid migration from deep shale formations to overlying aquifers in six different scenarios. These scenarios include poor well construction and hydraulic communication via fractures (natural and created) and nearby existing wells. As a first step, the subsurface migration simulations will examine realistic scenarios to assess the conditions necessary for hydraulic communication rather than the probability of migration occurring.

In a separate research project, concentrations of bromide and radium at public water supply intakes located downstream from wastewater treatment facilities discharging treated hydraulic fracturing wastewater are being estimated using surface water transport models.

Laboratory Studies

Laboratory studies are largely focused on identifying potential impacts of inadequately treating hydraulic fracturing wastewater and discharging it to rivers. Experiments are being designed to test how well common wastewater treatment processes remove selected contaminants from hydraulic fracturing wastewater, including radium and other metals. Other experiments are assessing whether or not hydraulic fracturing wastewater may contribute to the formation of disinfection byproducts during common drinking water treatment processes, with particular focus on the formation of brominated disinfection byproducts, which have significant health concerns at high exposure levels.

Samples of raw hydraulic fracturing wastewater, treated wastewater, and water from rivers receiving treated hydraulic fracturing wastewater have been collected for source apportionment studies. Results from laboratory analyses of these samples are being used to develop a method for determining if treated hydraulic fracturing wastewater is contributing to high chloride and bromide levels at downstream public water supplies.

Finally, existing analytical methods for selected chemicals are being tested, modified, and verified for use in this study and by others, as needed. Methods are being modified in cases where standard methods do not exist for the low-level detection of chemicals of interest or for use in the complex matrices associated with hydraulic fracturing wastewater. Analytical methods are currently being tested and modified for several classes of chemicals, including glycols, acrylamides, ethoxylated alcohols, disinfection byproducts, radionuclides, and inorganic chemicals.

Toxicity Assessments

The EPA has identified chemicals reportedly used in hydraulic fracturing fluids from 2005 to 2011 and chemicals found in flowback and produced water. Appendix A contains tables with over 1,000 of these chemicals identified. Chemical, physical, and toxicological properties are being compiled for chemicals with known chemical structures. Existing models are being used to estimate properties in cases where information is lacking. At this time, the EPA has not made any judgment about the extent of exposure to these chemicals when used in hydraulic fracturing fluids or found in hydraulic fracturing wastewater, or their potential impacts on drinking water resources.

Case Studies

Two rounds of sampling at five case study locations in Colorado, North Dakota, Pennsylvania, and Texas have been completed. In total, water samples have been collected from over 70 domestic water wells, 15 monitoring wells, and 13 surface water sources, among others. This research will help to identify the source of any contamination that may have occurred.

The EPA continues to work with industry partners to begin research activities at potential prospective case study locations, which involve sites where the research will begin before well construction. This will allow the EPA to collect baseline water quality data in the area. Water quality will be monitored for any changes throughout drilling, injection of fracturing fluids, flowback, and production. Samples of flowback and produced water will be used for other parts of the study, such as assessing the efficacy of wastewater treatment processes at removing contaminants in hydraulic fracturing wastewater.

Invigorating the Research Study Through Consultation and Peer Review

The EPA is committed to conducting a study that uses the best available science, independent sources of information, and a transparent, peer-reviewed process that will ensure the validity and accuracy of the results. The agency is working in consultation with other federal agencies, state and interstate regulatory agencies, industry, non-governmental organizations, and others in the private and public sector. In addition to workshops held in 2011, stakeholders and technical experts are being engaged through technical roundtables and workshops, with the first set of roundtables held November 14–16, 2012. These activities will provide the EPA with ongoing access to a broad range of expertise and data, timely and constructive technical feedback, and updates on changes in industry practices and technologies relevant to the study. Technical roundtables and workshops will be followed by webinars for the general public and posting of summaries on the study's website. Increased stakeholder engagement will also allow the EPA to educate and inform the public of the study's goals, design, and progress.

To ensure scientifically defensible results, each research project is subjected to quality assurance and peer review activities. Specific quality assurance activities performed by the EPA make sure that the agency's environmental data are of sufficient quantity and quality to support the data's intended use. Research products, such as papers or reports, will be subjected to both internal and external peer review before publication, which make certain that the data are used appropriately. Published results from the research projects will be synthesized in a report of results that will inform the research questions associated with each stage of the hydraulic fracturing water cycle. The EPA has designated the report of results as a "Highly Influential Scientific Assessment," which will undergo peer review by the EPA's Science Advisory Board, an independent and external federal advisory committee that conducts peer reviews of significant EPA research products and activities. The EPA will seek input from individual members of an *ad hoc* expert panel convened under the auspices of the EPA Science Advisory Board. The EPA will consider feedback from the individual experts in the development of the report of results.

Ultimately, the results of this study are expected to inform the public and provide decision-makers at all levels with high-quality scientific knowledge that can be used in decision-making processes.

Looking Forward: From This Report to the Next

1. Introduction

Oil and natural gas provided more energy in the United States for residential and industrial use than any other energy source in 2010—37% and 25%, respectively (US EIA, 2011a). Advances in technology and new applications of existing techniques, as well as supportive domestic energy policy and economic developments, have recently spurred an increase in oil and gas production across a wide range of geographic regions and geologic formations in the United States. Hydraulic fracturing is a technique used to produce economically viable quantities of oil and natural gas, especially from unconventional reservoirs, such as shale, tight sands, coalbeds, and other formations. Hydraulic fracturing involves the injection of fluids under pressures great enough to fracture the oil- and gas-producing formations. The resulting fractures are held open using "proppants," such as fine grains of sand or ceramic beads, to allow oil and gas to flow from small pores within the rock to the production well.

As the use of hydraulic fracturing has increased, so have concerns about its potential impact on human health and the environment, especially with regard to possible impacts on drinking water resources.[1] These concerns have increased as oil and gas exploration and development has spread from areas with a long history of conventional production to new areas with unconventional reservoirs, such as the Marcellus Shale, which extends from New York through parts of Pennsylvania, West Virginia, eastern Ohio, and western Maryland.

In response to public concerns and anticipated growth in the oil and gas industries, the US Congress urged the US Environmental Protection Agency (EPA) to examine the relationship between hydraulic fracturing and drinking water resources (USHR, 2009):

> *The conferees urge the agency to carry out a study on the relationship between hydraulic fracturing and drinking water, using a credible approach that relies on the best available science, as well as independent sources of information. The conferees expect the study to be conducted through a transparent, peer-reviewed process that will ensure the validity and accuracy of the data. The Agency shall consult with other federal agencies as well as appropriate state and interstate regulatory agencies in carrying out the study, which should be prepared in accordance with the agency's quality assurance principles.*

In 2010, the EPA launched the planning of the current study and included multiple opportunities for the public and the Science Advisory Board[2] to provide input during the study planning process.[3] The EPA's *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*

[1] Common concerns raised by stakeholders include potential impacts to air quality and ecosystems as well as sociologic effects (e.g., community changes). A more comprehensive list of concerns reported to the EPA during initial stakeholder meetings can be found in Appendix C of the EPA's *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (EPA/600/R-11/121).

[2] The Science Advisory Board is an independent and external federal advisory committee that conducts peer reviews of scientific matters for the EPA.

[3] During summer 2010, the EPA engaged stakeholders in a dialogue about the study through facilitated meetings. Summaries of these meetings are available at http://www.epa.gov/hfstudy/publicoutreach.html.

(subsequently referred to as the "Study Plan") was finalized in November 2011 (US EPA, 2011e). The purpose of the EPA's current study is to assess the potential impacts of hydraulic fracturing on drinking water resources,[4] if any, and to identify the driving factors that may affect the severity and frequency of such impacts. This study includes research on hydraulic fracturing to extract oil and gas from shale, tight sand, and coalbeds, focusing primarily on hydraulic fracturing of shale for gas extraction. It is intended to assess the potential impacts to drinking water resources from hydraulic fracturing as it is currently practiced and has been practiced in the past, and it is not intended to evaluate best management practices or new technologies. Emphasis is placed on identifying possible exposure pathways and hazards, providing results that can then be used to assess the potential risks to drinking water resources from hydraulic fracturing. Ultimately, results from the study are intended to inform the public and provide policymakers at all levels with high-quality scientific knowledge that can be used in decision-making.

The body of this progress report presents the research progress made by the EPA, as of September 2012, regarding the potential impacts of hydraulic fracturing on drinking water resources; information presented as part of this report cannot be used to draw conclusions about the proposed research questions. Chapters 3 through 7 provide project-specific updates that include background information on the research project, a description of the research methods, an update on the current status and next steps of the work, as well as a summary of the quality assurance (QA) activities to date;[5] these chapters are written for scientific and engineering professionals. All projects described in this progress report are currently underway, and nearly all are expected to be completed in the next few years. Results from individual projects will undergo peer review prior to publication. The EPA intends to synthesize the published results from these research projects in a report of results, described in more detail in Section 9.3.

1.1. Stakeholder Engagement

The EPA is committed to conducting this study in an open and transparent manner. During the development of the study, the EPA met with stakeholders from the general public; federal, state, regional and local agencies; tribes; industry; academia; and non-governmental organizations. Webinars and meetings with these separate groups were held to discuss the study scope, data gaps, opportunities for sharing data and conducting joint studies, current policies and practices for protecting drinking water resources, and the public engagement process.

In addition to webinars and meetings, the EPA held a series of technical workshops in early 2011 on four subjects integral to hydraulic fracturing and the study: chemical and analytical methods, well construction and operation, chemical fate and transport, and water resource management.[6] Technical experts from the oil and natural gas industry, academia, consulting firms, commercial laboratories, state and federal agencies, and environmental organizations were chosen to

[4] For this study, "drinking water resources" are considered to be any body of water, ground or surface, that could (now or in the future) serve as a source of drinking water for public or private water supplies.

[5] QA activities include implementation of quality assurance project plans (QAPPs), technical systems audits (TSAs), and audits of data quality (ADQs). These activities are described further in Section 8.1.

[6] Proceedings from the four technical workshops are available at http://www.epa.gov/hfstudy/technicalworkshops.html.

participate in each of the workshops. The workshops gave EPA scientists the opportunity to interact with technical experts regarding current hydraulic fracturing technology and practices and to identify and design research related to the potential impacts of hydraulic fracturing on drinking water resources. Information presented during the workshops is being used to inform ongoing research.

The EPA has recently announced additional opportunities for stakeholder engagement. The goals of this enhanced engagement process are to improve public understanding of the study, ensure that the EPA is current on changes in industry practices and technologies so that the report of results reflects an up-to-date picture of hydraulic fracturing operations, and obtain timely and constructive feedback on ongoing research projects.

Stakeholders and technical experts are being engaged through the following activities:

- *Technical roundtables* with invited experts from diverse stakeholder groups to discuss the work underway to answer key research questions and identify possible topics for technical workshops. The roundtables also give the EPA access to a broad and balanced range of expertise as well as data from outside the agency.
- *Technical workshops* with experts invited to participate in more in-depth discussions and share expertise on discrete technical topics relevant to the study.
- *Information requests* through a *Federal Register* notice, requesting that the public submit relevant studies and data—particularly peer-reviewed studies—for the EPA's consideration, including information on advances in industry practices and technologies.
- *Study updates* to a wide range of stakeholders, including the general public, states, tribes, academia, non-governmental organizations, industry, professional organizations, and others.
- *Periodic briefings* with the EPA's Science Advisory Board to provide updates on the progress of the study.

These efforts will help:

- Inform the EPA's interpretation of the research being conducted as part of this study.
- Identify additional data and studies that may inform the report or results.
- Identify future research needs.

Additional information on the ongoing stakeholder engagement process can be found in Appendix B and online at http://www.epa.gov/hfstudy/. The website includes the presentations made by the EPA during the technical roundtables held in November 2012 as well as a list of roundtable participants. Readers are encouraged to check this website for up-to-date information on upcoming webinars for the general public and proceedings from technical workshops, which are currently scheduled for spring 2013.

2. Overview of the Research Program

The EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* is organized into five topics according to the potential for interaction between hydraulic fracturing and drinking water resources. These five topics—stages of the hydraulic fracturing water cycle—are illustrated in Figure 1 and include (1) water acquisition, (2) chemical mixing, (3) well injection, (4) flowback and produced water, and (5) wastewater treatment and waste disposal.

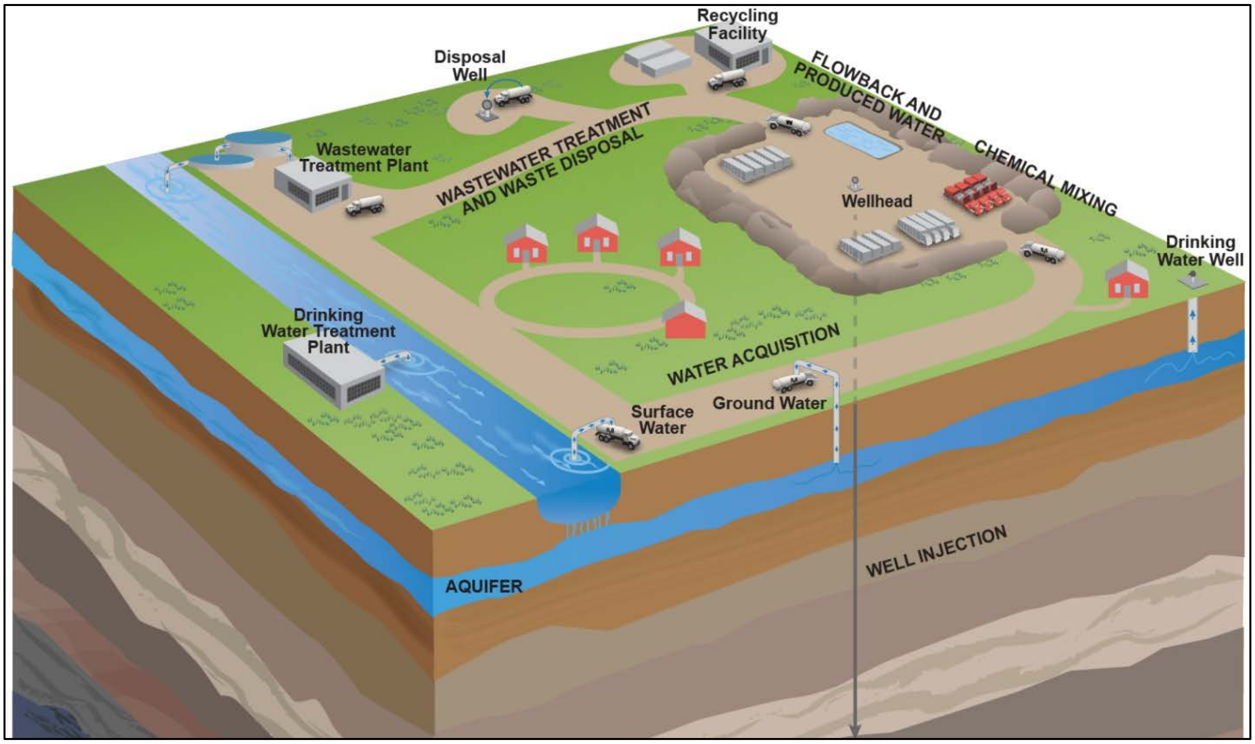

Figure 1. Illustration of the five stages of the hydraulic fracturing water cycle. The cycle includes the acquisition of water needed for the hydraulic fracturing fluid, onsite mixing of chemicals with the water to create the hydraulic fracturing fluid, injection of the fluid under high pressures to fracture the oil- or gas-containing formation, recovery of flowback and produced water (hydraulic fracturing wastewater) after the injection is complete, and treatment and/or disposal of the wastewater.

Figure 2 lists potential drinking water issues identified for each stage of the hydraulic fracturing water cycle.

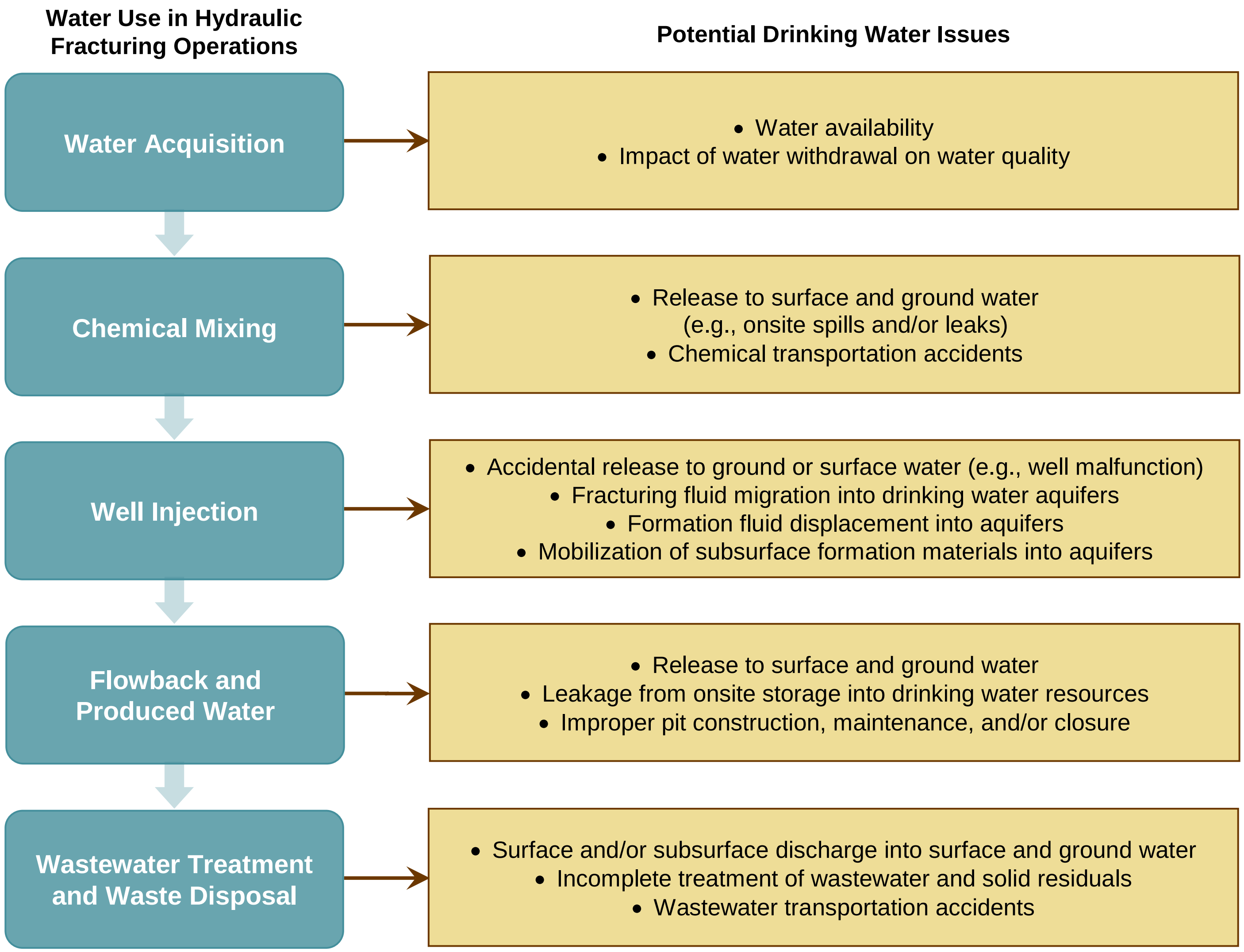

Figure 2. Potential drinking water issues associated with each stage of the hydraulic fracturing water cycle. The potential issues help to define the fundamental research questions. Figure reprinted from the Study Plan (US EPA, 2011e).

As described in the Study Plan, the potential issues led to the development of primary research questions that are supported by secondary research questions. The secondary research questions are addressed by the research projects listed in Table 1. Table 1 also provides short titles and descriptions of the research projects; these titles are used throughout the rest of the report.

Table 1. Titles and descriptions of the research projects conducted as part of the EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. These titles are used throughout the rest of the report. Detailed descriptions of each project can be found in Chapters 3 through 7.

Research Project	Description
Analysis of Existing Data	
Literature Review	Review and assessment of existing papers and reports, focusing on peer-reviewed literature
Spills Database Analysis	Analysis of selected federal and state databases for information on spills of hydraulic fracturing fluids and wastewaters
Service Company Analysis	Analysis of information provided by nine hydraulic fracturing service companies in response to a September 2010 information request on hydraulic fracturing operations
Well File Review	Analysis of information provided by nine oil and gas operators in response to an August 2011 information request for 350 well files
FracFocus Analysis	Analysis of data compiled from FracFocus, the national hydraulic fracturing chemical registry operated by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission
Scenario Evaluations	
Subsurface Migration Modeling	Numerical modeling of subsurface fluid migration scenarios that explore the potential for gases and fluids to move from the fractured zone to drinking water aquifers
Surface Water Modeling	Modeling of concentrations of selected chemicals at public water supplies downstream from wastewater treatment facilities that discharge treated hydraulic fracturing wastewater to surface waters
Water Availability Modeling	Assessment and modeling of current and future scenarios exploring the impact of water usage for hydraulic fracturing on drinking water availability in the Upper Colorado River Basin and the Susquehanna River Basin
Laboratory Studies	
Source Apportionment Studies	Identification and quantification of the source(s) of high bromide and chloride concentrations at public water supply intakes downstream from wastewater treatment plants discharging treated hydraulic fracturing wastewater to surface waters
Wastewater Treatability Studies	Assessment of the efficacy of common wastewater treatment processes on removing selected chemicals found in hydraulic fracturing wastewater
Br-DBP Precursor Studies	Assessment of the ability of bromide and brominated compounds present in hydraulic fracturing wastewater to form brominated disinfection byproducts (Br-DBPs) during drinking water treatment processes
Analytical Method Development	Development of analytical methods for selected chemicals found in hydraulic fracturing fluids or wastewater

Table continued on next page

Table continued from previous page	
Research Project	**Description**
	Toxicity Assessment
Toxicity Assessment	Toxicity assessment of chemicals reportedly used in hydraulic fracturing fluids or found in hydraulic fracturing wastewater
	Case Studies
Retrospective Studies	*Investigations of whether reported drinking water impacts may be associated with or caused by hydraulic fracturing activities*
Las Animas and Huerfano Counties, Colorado	Investigation of potential drinking water impacts from coalbed methane extraction in the Raton Basin
Dunn County, North Dakota	Investigation of potential drinking water impacts from a well blowout during hydraulic fracturing for oil in the Bakken Shale
Bradford County, Pennsylvania	Investigation of potential drinking water impacts from shale gas development in the Marcellus Shale
Washington County, Pennsylvania	Investigation of potential drinking water impacts from shale gas development in the Marcellus Shale
Wise County, Texas	Investigation of potential drinking water impacts from shale gas development in the Barnett Shale
Prospective Studies	*Investigation of potential impacts of hydraulic fracturing through collection of samples from a site before, during, and after well pad construction and hydraulic fracturing*

Each project has been designed to inform answers to one or more of the secondary research questions with multiple projects informing answers to each secondary research question. The answers to the secondary research questions will then inform answers to the primary research questions. Figure 3 illustrates the relationship between water cycle stage, primary and secondary research questions, and research projects.

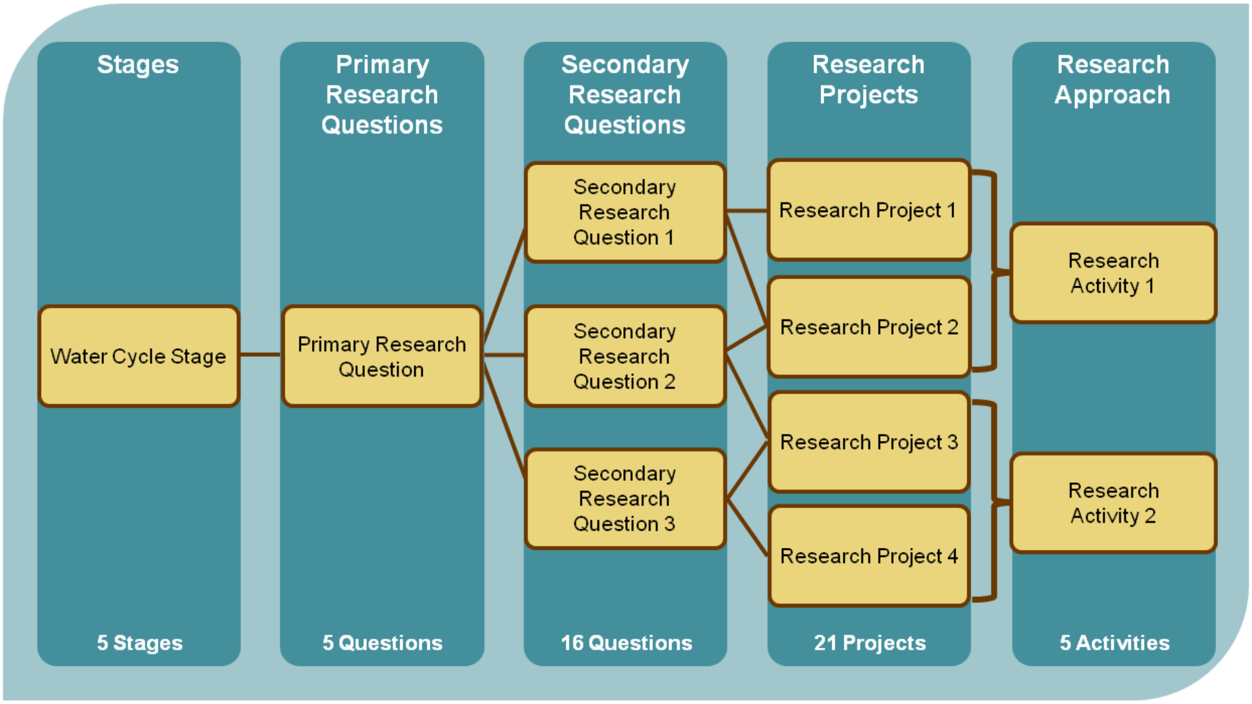

Figure 3. Illustration of the structure of the EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. Results from multiple research projects may be used to inform answers to one secondary research question. Additionally, one research project may provide information to help answer multiple secondary research questions. Each research project falls under one type of research activity.

2.1. Research Questions

This section describes the activities that occur during each stage of the water cycle, potential drinking water issues, and primary research questions, which are listed in Figure 4.[7] It also introduces the secondary research questions and lists the associated research projects. This section is intended to offer a broad overview of the EPA's study and direct the reader to further information in subsequent chapters of this progress report. Later chapters (Chapters 3 through 7) contain detailed information about the progress of individual research projects listed in Tables 2 through 6 below.

[7] Additional information on the hydraulic fracturing water cycle stages and research questions can be found in the Study Plan.

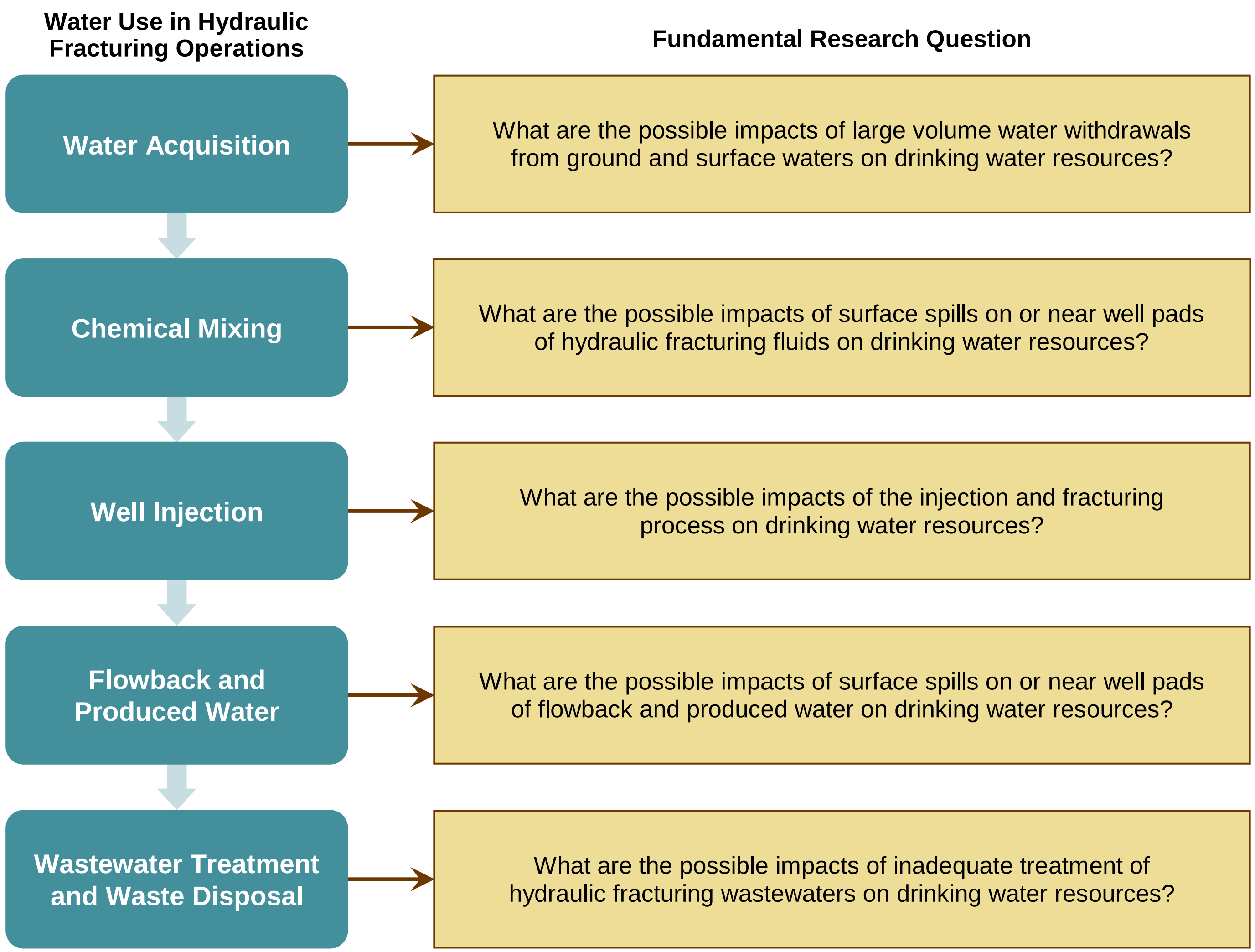

Figure 4. Fundamental research questions posed for each stage of the hydraulic fracturing water cycle. Figure reprinted from the Study Plan (US EPA, 2011e).

2.1.1. Water Acquisition: What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?

Hydraulic fracturing fluids are usually water-based, with approximately 90% of the injected fluid composed of water (GWPC and ALL Consulting, 2009). Estimates of water needs per well have been reported to range from 65,000 gallons for coalbed methane (CBM) production up to 13 million gallons for shale gas production, depending on the characteristics of the formation being fractured and the design of the production well and fracturing operation (GWPC and ALL Consulting, 2009; Nicot et al., 2011). Five million gallons of water are equivalent to the water used by approximately 50,000 people for one day.[8] The source of the water may vary, but is typically ground water, surface water, or treated wastewater, as illustrated in Figure 5. Industry trends suggest a recent shift to using treated and recycled produced water (or other treated wastewaters) as base fluids in hydraulic fracturing operations.

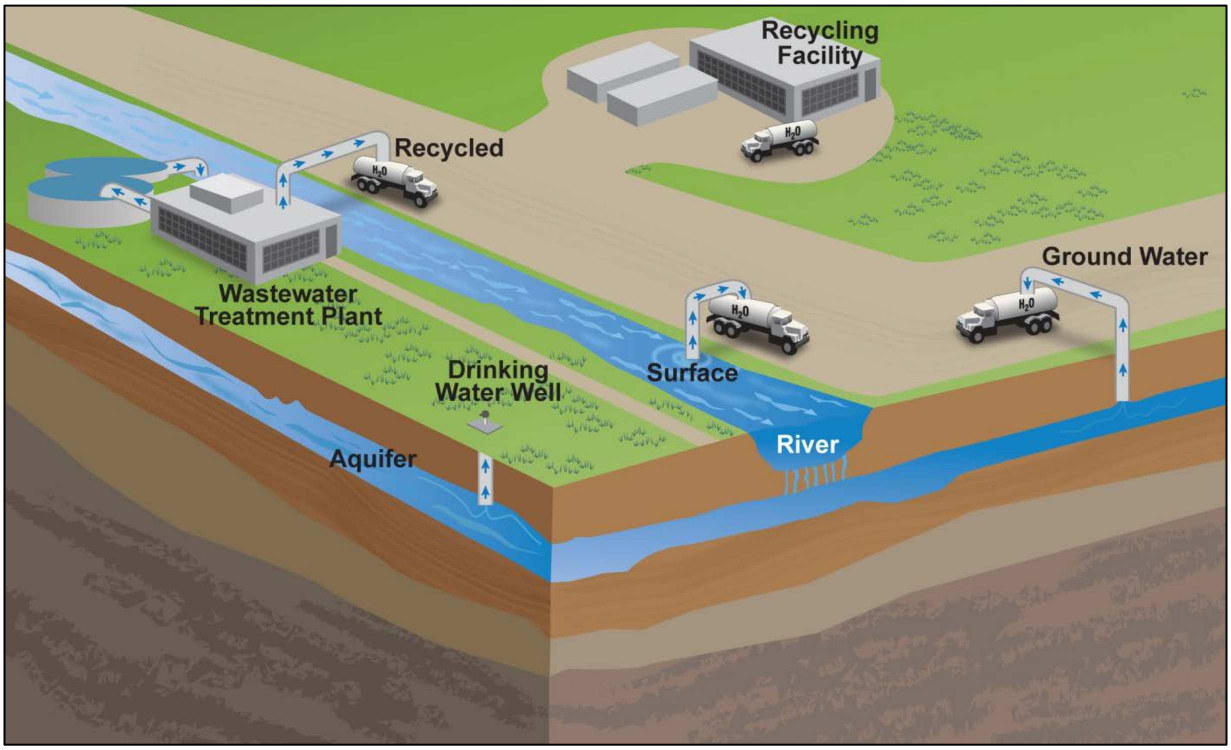

Figure 5. Water acquisition. Water for hydraulic fracturing can be drawn from a variety of sources including surface water, ground water, treated wastewater generated during previous hydraulic fracturing operations, and other types of wastewater.

The EPA is working to better characterize the amounts and sources of water currently being used for hydraulic fracturing operations, including recycled water, and how these withdrawals may impact local drinking water quality and availability. To that end, secondary research questions have been developed, as well as the research projects listed in Table 2.

[8] This assumes that the average American uses approximately 100 gallons of water per day. See http://www.epa.gov/watersense/pubs/indoor.html.

Table 2. Secondary research questions and applicable research projects identified for the water acquisition stage of the hydraulic fracturing water cycle. The table also identifies the sections of this report that contain detailed information about the listed research projects.

Secondary Research Questions	Applicable Research Projects	Section
How much water is used in hydraulic fracturing operations, and what are the sources of this water?	Literature Review	3.1
	Service Company Analysis	3.3
	Well File Review	3.4
	FracFocus Analysis	3.5
	Water Availability Modeling	4.3
How might water withdrawals affect short- and long-term water availability in an area with hydraulic fracturing activity?	Literature Review	3.1
	Water Availability Modeling	4.3
What are the possible impacts of water withdrawals for hydraulic fracturing operations on local water quality?	Literature Review	3.1

2.1.2. Chemical Mixing: What are the possible impacts of surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources?

Once onsite, water is mixed with chemicals to create the hydraulic fracturing fluid that is pumped down the well, as illustrated in Figure 6. The fluid serves two purposes: to create pressure to propagate fractures and to carry the proppant into the fracture. Chemicals are added to the fluid to change its properties (e.g., viscosity, pH) in order to optimize the performance of the fluid. Roughly 1% of water-based hydraulic fracturing fluids are composed of various chemicals, which is equivalent to 50,000 gallons for a shale gas well that uses 5 million gallons of fluid.

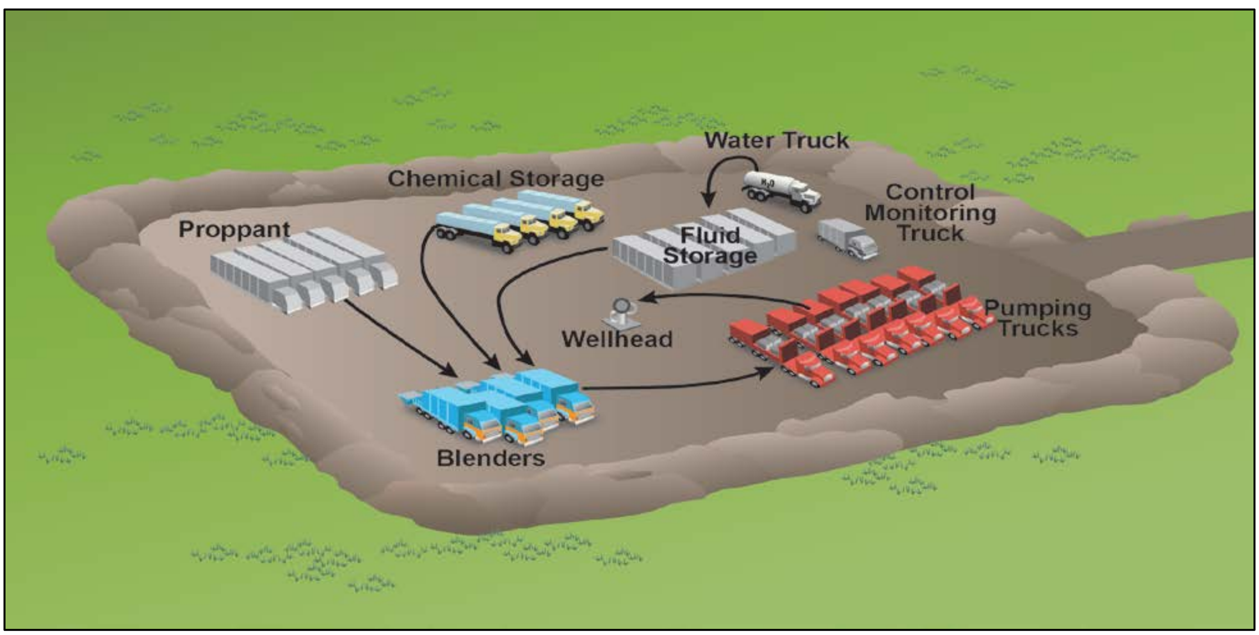

Figure 6. Chemical mixing. Water is mixed with chemicals and proppant onsite to create the hydraulic fracturing fluid immediately before injection.

Hydraulic fracturing operations require large quantities of supplies, equipment, water, and vehicles. Onsite storage, mixing, and pumping of hydraulic fracturing fluids may result in accidental releases, such as spills or leaks.[9] Released fluids could then flow into nearby surface water bodies or infiltrate into the soil and near-surface ground water, potentially reaching drinking water resources. In order to explore the potential impacts of surface releases of hydraulic fracturing fluids on drinking water resources, the EPA is: (1) compiling information on reported spills; (2) identifying chemical additives used in hydraulic fracturing fluids and their chemical, physical, and toxicological properties; and (3) gathering data on the environmental fate and transport of selected hydraulic fracturing chemical additives. These activities correspond to the secondary research questions and research projects described in Table 3.

Table 3. Secondary research questions and applicable research projects identified for the chemical mixing stage of the hydraulic fracturing water cycle. The table also identifies the sections of this report that contain detailed information about the listed research projects.

Secondary Research Questions	Applicable Research Projects	Section
What is currently known about the frequency, severity, and causes of spills of hydraulic fracturing fluids and additives?	Literature Review	3.1
	Spills Database Analysis	3.2
	Service Company Analysis	3.3
	Well File Review	3.4
What are the identities and volumes of chemicals used in hydraulic fracturing fluids, and how might this composition vary at a given site and across the country?	Literature Review	3.1
	Service Company Analysis	3.3
	FracFocus Analysis	3.5
	Analytical Method Development	5.4
What are the chemical, physical, and toxicological properties of hydraulic fracturing chemical additives?	Toxicity Assessment	6
If spills occur, how might hydraulic fracturing chemical additives contaminate drinking water resources?	Literature Review	3.1
	Retrospective Case Studies	7

2.1.3. Well Injection: What are the possible impacts of the injection and fracturing process on drinking water resources?

The hydraulic fracturing fluid is pumped down the well at pressures great enough to fracture the oil- or gas-containing rock formation, as shown in Figure 7 for both horizontal and vertical well completions. Production wells are drilled and completed in order to best and most efficiently drain the geological reservoir of its hydrocarbon resources. This means that wells may be drilled and completed vertically (panel b in Figure 7), vertically at the top and then horizontally at the bottom (panel a), or in other configurations deviating from vertical, known as "deviated wells."

[9] As noted in the Study Plan, transportation-related spills of hydraulic fracturing chemical additives and wastewater are outside of the scope of the current study.

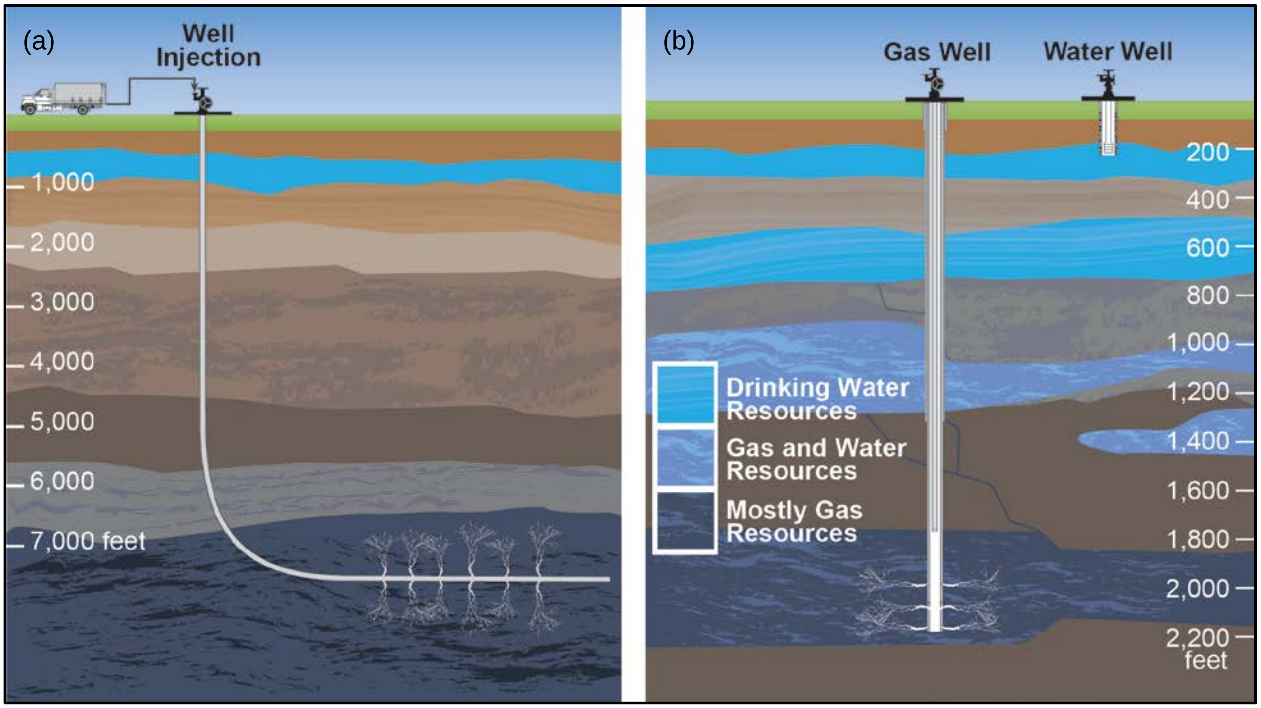

Figure 7. Well injection. During injection, hydraulic fracturing fluids are pumped into the well at high pressures, which are sustained until the fractures are formed. Hydraulic fracturing can be used with both (a) deep, horizontal well completions and (b) shallower, vertical well completions. Horizontal wells are typically used in formations such as tight sandstones, carbonate rock, and shales. Vertical wells are typically used in formations for conventional production and coalbed methane.

Within this stage of the hydraulic fracturing water cycle, the EPA is studying a number of scenarios that may lead to changes in local drinking water resources, including well construction failure and induced fractures intersecting existing natural (e.g., faults or fractures) or man-made (e.g., abandoned wells) features that may act as conduits for contaminant transport. Table 4 lists the secondary research questions and research projects that address these concerns.

Table 4. Secondary research questions and applicable research projects identified for the well injection stage of the hydraulic fracturing water cycle. The table also identifies the sections of this report that contain detailed information about the listed research projects.

Secondary Research Questions	Applicable Research Projects	Section
How effective are current well construction practices at containing gases and fluids before, during, and after fracturing?	Literature Review	3.1
	Service Company Analysis	3.3
	Well File Review	3.4
	Subsurface Migration Modeling	4.1
	Retrospective Case Studies	7
Can subsurface migration of fluids or gases to drinking water resources occur, and what local geologic or man-made features might allow this?	Literature Review	3.1
	Service Company Analysis	3.3
	Well File Review	3.4
	Subsurface Migration Modeling	4.1
	Retrospective Case Studies	7

2.1.4. 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?

When the injection pressure is reduced, the direction of fluid flow reverses, leading to the recovery of flowback and produced water. For this study, "flowback" is the fluid returned to the surface after hydraulic fracturing has occurred, but before the well is placed into production, while "produced water" is the fluid returned to the surface after the well has been placed into production.[10] They are collectively referred to as "hydraulic fracturing wastewater" and may contain chemicals injected as part of the hydraulic fracturing fluid, substances naturally occurring in the oil- or gas-producing formation,[11] hydrocarbons, and potential reaction and degradation products.

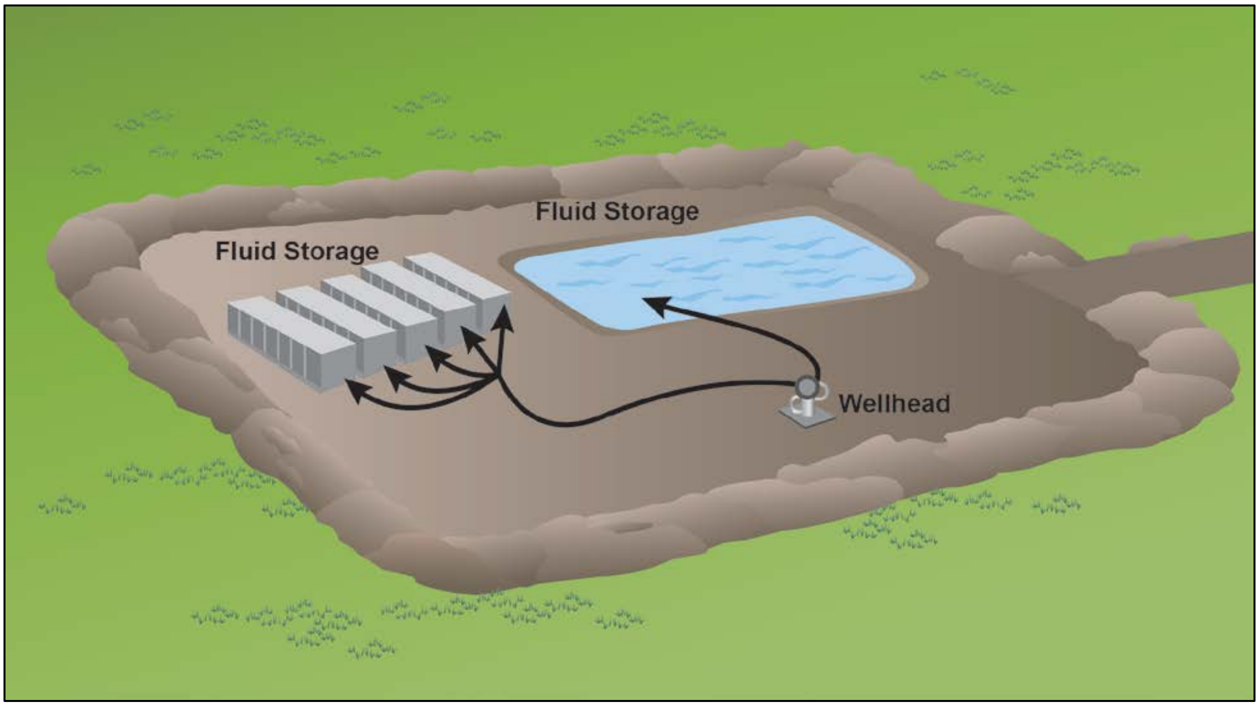

Figure 8. Flowback and produced water. During this stage, the pressure on the hydraulic fracturing fluid is reduced and the flow is reversed. The flowback and produced water contain hydraulic fracturing fluids, native formation water, and a variety of naturally occurring substances picked up by the wastewater during the fracturing process. The fluids are separated from any gas or oil produced with the water and stored in either tanks or an open pit.

As depicted in Figure 8, the wastewater is typically stored onsite in impoundment pits or tanks. Onsite transfer and storage of hydraulic fracturing wastewater may result in accidental releases, such as spills or leaks, which may reach nearby drinking water resources. The potential impacts to drinking water resources from flowback and produced water are similar to the potential impacts identified in the chemical mixing stage of the hydraulic fracturing water cycle, with the exception of different fluid compositions for injected fluids and wastewater. Therefore, the secondary research

[10] Produced water is a product of all oil and gas wells, including wells that have not been hydraulically fractured.

[11] Substances naturally found in hydraulically fractured formations may include brines, trace elements (e.g., mercury, lead, arsenic), naturally occurring radioactive material (e.g., radium, thorium, uranium), gases (e.g., natural gas, hydrogen sulfide), and organic material (e.g., organic acids, polycyclic aromatic hydrocarbons, volatile organic compounds).

questions and associated research projects are similar. The secondary research questions and applicable research projects are listed in Table 5.

Table 5. Secondary research questions and applicable research projects identified for the flowback and produced water stage of the hydraulic fracturing water cycle. The table also identifies the sections of this report that contain detailed information about the listed research projects.

Secondary Research Questions	Applicable Research Projects	Section
What is currently known about the frequency, severity, and causes of spills of flowback and produced water?	Literature Review	3.1
	Spills Database Analysis	3.2
	Service Company Analysis	3.3
	Well File Review	3.4
What is the composition of hydraulic fracturing wastewaters, and what factors might influence this composition?	Literature Review	3.1
	Service Company Analysis	3.3
	Well File Review	3.4
	Analytical Method Development	5.4
What are the chemical, physical, and toxicological properties of hydraulic fracturing wastewater constituents?	Toxicity Assessment	6
If spills occur, how might hydraulic fracturing wastewater contaminate drinking water resources?	Literature Review	3.1
	Retrospective Case Studies	7

2.1.5. Wastewater Treatment and Waste Disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

Estimates of the fraction of hydraulic fracturing wastewater recovered vary by geologic formation and range from 10% to 70% of the injected hydraulic fracturing fluid (GWPC and ALL Consulting, 2009; US EPA, 2011f). For a hydraulic fracturing job that uses 5 million gallons of hydraulic fracturing fluid, this means that between 500,000 and 3.5 million gallons of fluid will be returned to the surface. As illustrated in Figure 9, the wastewater is generally managed through disposal into deep underground injection control (UIC) wells,[12] treatment followed by discharge to surface water bodies,[13] or treatment followed by reuse.

[12] Underground injection of fluids related to oil and gas production (including flowback and produced water) is authorized by the Safe Drinking Water Act.

[13] Treatment processes involving discharge to surface waters are authorized by the Clean Water Act and the National Pollutant Discharge Elimination System program.

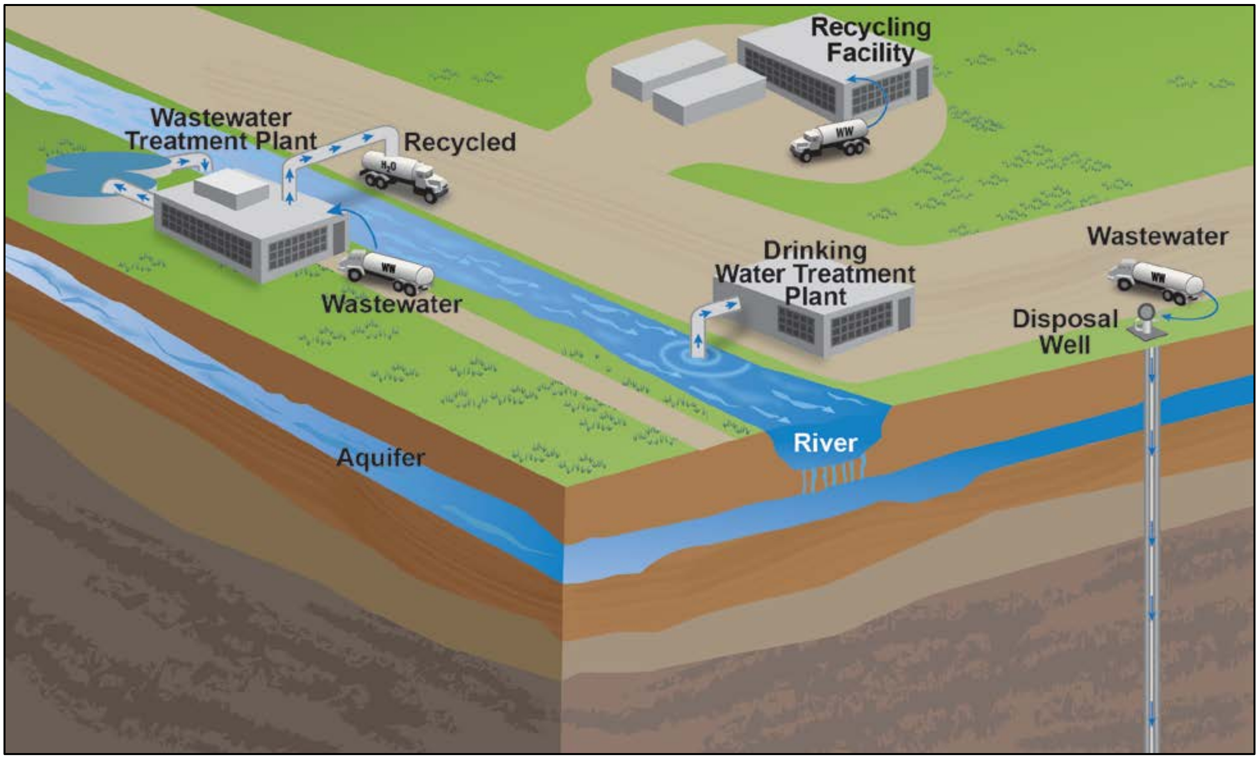

Figure 9. Wastewater treatment and waste disposal. Flowback and produced water is frequently disposed of in deep injection wells, but may also be trucked, or in some cases piped, to a disposal or recycling facility. Once treated, the wastewater may be reused in subsequent hydraulic fracturing operations or discharged to surface water.

Understanding the treatment, disposal, and reuse of flowback and produced water from hydraulic fracturing activities is important. For example, contaminants present in these waters may be inadequately treated at publicly owned treatment works (POTWs), discharges from which may threaten downstream drinking water intakes, as depicted in Figure 9.[14] Table 6 summarizes the secondary research questions and the applicable research projects for each question.

[14] As noted in the Study Plan, this study does not propose to evaluate the potential impacts of underground injection or the associated potential impacts due to transport and storage leading up to ultimate disposal in a UIC well.

Table 6. Secondary research questions and applicable research projects identified for the wastewater treatment and waste disposal stage of the hydraulic fracturing water cycle. The table also identifies the sections of this report that contain detailed information about the listed research projects.

Secondary Research Questions	Applicable Research Projects	Section
What are the common treatment and disposal methods for hydraulic fracturing wastewater, and where are these methods practiced?	Literature Review	3.1
	Well File Review	3.4
	FracFocus Analysis	3.5
How effective are conventional POTWs and commercial treatment systems in removing organic and inorganic contaminants of concern in hydraulic fracturing wastewater?	Literature Review	3.1
	Wastewater Treatability Studies	5.2
What are the potential impacts from surface water disposal of treated hydraulic fracturing wastewater on drinking water treatment facilities?	Literature Review	3.1
	Surface Water Modeling	4.2
	Source Apportionment Studies	5.1
	Br-DBP Precursor Studies	5.3

2.2. Environmental Justice

Environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.[15]

During the planning process, some stakeholders raised concerns about environmental justice and hydraulic fracturing, while others stated that hydraulic fracturing–related activities provide benefits to local communities. In its review of the draft Study Plan, the EPA's Science Advisory Board supported the inclusion in the study of an environmental justice analysis as it pertains to the potential impacts on drinking water resources. The EPA, therefore, attempted to conduct a screening to provide insight into the research questions in Table 7.

Table 7. Research questions addressed by assessing the demographics of locations where hydraulic fracturing activities are underway.

Fundamental Research Question	Secondary Research Questions
Does hydraulic fracturing disproportionately occur in or near communities with environmental justice concerns?	• Are large volumes of water being disproportionately withdrawn from drinking water resources that serve communities with environmental justice concerns? • Are hydraulically fractured oil and gas wells disproportionately located near communities with environmental justice concerns? • Is wastewater from hydraulic fracturing operations being disproportionately treated or disposed of (via POTWs or commercial treatment systems) in or near communities with environmental justice concerns?

[15] The EPA's definition of environmental justice can be found at http://www.epa.gov/environmentaljustice/basics/index.html and was informed by E.O. 12898.

Environmental justice screening uses easily obtained environmental and demographic information to highlight locations where additional review (i.e., information collection or analysis) may be warranted (US EPA, 2012c). Screenings do not examine whether co-location of specific activities and communities with certain demographics (e.g., low-income, non-white minority, young children, and elderly subpopulations) may lead to any positive or negative impacts on a given community.

Nationwide data on the locations of water withdrawals and wastewater treatment associated with hydraulic fracturing activities are difficult to obtain. The EPA was not able to identify comprehensive data sources that identify the locations of water withdrawals associated with hydraulic fracturing or facilities receiving hydraulic fracturing wastewaters. Geographic data on hydraulic fracturing-only water use (rather than general oil and gas water use) are limited, and the available data are aggregated by regions too large for an environmental justice analysis. Data on commercial and publicly owned treatment works accepting hydraulic fracturing wastewater were found to be inconsistent between states or difficult to obtain.

Data on the locations of hydraulically fractured oil and gas production wells considered for the environmental justice screen are available from two sources: data provided to the EPA from nine hydraulic fracturing service companies (see Section 3.3) and data obtained from FracFocus (Section 3.5). The service company data set includes county-level locations of approximately 25,000 oil and gas wells hydraulically fractured between September 2009 and October 2010. In total, 590 of the 3,221 counties in the United States contained wells hydraulically fractured by the nine service companies during the period under analysis. In comparison, the FracFocus data set includes latitude/longitude and county-level information on the location of roughly 11,000 wells hydraulically fractured between January 2009 and February 2012. In total, only 251 of the 3,221 counties in the United States contained wells reported to FracFocus during this time period.

The county-level resolution provided by the service company data set is insufficient for determining whether hydraulic fracturing activities are occurring in communities that possess characteristics associated with environmental justice populations. Finer resolution is needed since counties can contain a multitude of communities, townships, and even cities, with diverse populations. Data obtained from FracFocus provide well locations at finer resolution (i.e., specific latitude/longitude coordinates), which may provide further opportunity for either state- or nationwide environmental justice screens.

2.3. Changes to the Research Program

The EPA has significantly modified some of the research projects since the publication of the Study Plan. These modifications are discussed below.

FracFocus Analysis. In early 2011, the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission jointly launched a new national registry for chemicals used in hydraulic fracturing, called FracFocus. This registry is an online repository where oil and gas well operators can upload information regarding the chemical composition of hydraulic fracturing fluids used in specific oil and gas production wells. Extracting data from FracFocus allows the EPA to gather publicly available, nationwide data on the water volumes and chemicals used in hydraulic fracturing operations, as reported by oil and gas operating companies. These data are being analyzed to identify chemicals used in hydraulic fracturing fluids as well as the geographic distribution of water and chemical use.

Prospective Case Studies. The EPA identified the location of one of the prospective case studies as De Soto Parish, Louisiana, in the Haynesville Shale. Due to scheduling conflicts, the location in De Soto Parish is no longer being considered for a prospective case study.

The EPA continues to work with industry partners to identify locations and develop research activities for prospective case studies. As part of these case studies, the EPA intends to monitor local water quality for up to a year or more after hydraulic fracturing occurs. It is likely, therefore, that the prospective case studies will be completed after the report of results. In that event, results from any prospective case studies will be published in a follow-up report.

Chemical Prioritization. As part of the toxicity assessment research project, the EPA is compiling chemical, physical, and toxicological properties for chemicals reportedly used in hydraulic fracturing fluids and/or detected in flowback and produced water. One aspect of the planned second phase of this work was to include prioritizing a subset of these chemicals for future toxicity screening using high throughput screening assays. However, consistent with recommendations of the Science Advisory Board, the agency will not conduct high throughput screening assays at this time on a subset of these chemicals, but will continue efforts to identify, evaluate, and prioritize existing toxicity data.

Reactions Between Hydraulic Fracturing Fluids and Shale. Based on research already being conducted by the US Department of Energy and academic institutions on the interactions between hydraulic fracturing fluids and various rock formations,[16] the EPA has decided to discontinue its work in this area. The EPA continues to believe in the importance of research to address research questions associated with this project, but has decided to rely upon work being conducted by another federal agency.

Therefore, the EPA has removed two research questions associated with this project:

- How might hydraulic fracturing fluids change the fate and transport of substances in the subsurface through geochemical interactions?
- What are the chemical, physical, and toxicological properties of substances in the subsurface that may be released by hydraulic fracturing operations?

2.4. Research Approach

The research projects listed in Table 1 and discussed in detail in Chapters 3 through 7 of this progress report require a broad range of scientific expertise in environmental and petroleum engineering, ground water hydrology, fate and transport modeling, and toxicology, as well as many other disciplines. Consequently, the EPA is using a transdisciplinary research approach that

[16] See, for example, research underway by the US Department of Energy's National Energy Technology Laboratory (http://www.netl.doe.gov/publications/factsheets/rd/R%26D166.pdf) and Penn State 3S Laboratory (http://3s.ems.psu.edu/research.html).

integrates various types of expertise from inside and outside the agency. The research projects fall into five categories: analysis of existing data, case studies, scenario modeling and evaluation, laboratory studies, and toxicology assessments. Table 8 summarizes the five main types of research activities occurring as part of this study and their objectives. Figure 3 illustrates the relationship between the research activities and the research projects and questions.

Table 8. Research activities and objectives. Each research project falls under one type of research activity.

Activity	Objective
Analysis of existing data	Gather and summarize existing data from various sources to provide current information on hydraulic fracturing activities; includes information requested of hydraulic fracturing service companies and oil and gas operators*
Scenario evaluations	Use computer modeling to assess the potential for hydraulic fracturing to impact drinking water resources
Laboratory studies	Conduct targeted experiments to test and develop analytical detection methods and to study the fate and transport of selected chemicals during wastewater treatment and discharge to surface water
Toxicity assessment	Identify chemicals used in hydraulic fracturing fluids or reported to be in hydraulic fracturing wastewater and compile available chemical, physical, and toxicological properties
Case studies	
Retrospective	Study sites with reported contamination to understand the underlying causes and potential impacts to drinking water resources
Prospective	Develop understanding of hydraulic fracturing processes and their potential impacts on drinking water resources

* For more information on the information requests, see http://www.epa.gov/hfstudy/analysis-of-existing-data.html.

3. Analysis of Existing Data

The objective of this approach is to gather and summarize data from many sources to provide current information on hydraulic fracturing activities. The EPA is collecting and analyzing data on chemical spills, surface water discharges, and chemicals found in hydraulic fracturing fluids and wastewater, among others. These data have been collected from a variety of sources, including state and federal agencies, industry, and public sources. Included among these sources is information received after the September 2010 letter requesting data from nine hydraulic fracturing service companies and the August 2011 letter requesting well files from nine oil and gas well operators.[17] This chapter includes progress reports for the following projects:

3.1. Literature Review

3.1.1. Relationship to the Study

The EPA is gathering and assessing literature relevant to all secondary research questions.

3.1.2. Project Introduction

An extensive review of existing literature is an important component of the EPA's study of the relationship between hydraulic fracturing and drinking water resources. The objective of this literature review is to identify and analyze data and literature relevant to all secondary research questions. This objective will be met by reviewing a wide range of information sources on the five stages of the hydraulic fracturing water cycle. Sources identified through the literature review are subject to a quality review to support decisions regarding their inclusion in the EPA's report of

[17] Copies of these information requests are available at http://www.epa.gov/hfstudy/analysis-of-existing-data.html.

results. Information gathered during the literature review will be synthesized with results from the other research projects described in this progress report to answer the research questions posed in the Study Plan and summarized in Chapter 2.

3.1.3. Research Approach

Existing literature and data is being identified through a variety of methods, including conducting a search of published documents, searching online databases such as OnePetro[18] and Web of Knowledge℠ [19] and reviewing materials provided to the EPA through technical workshops, comment submissions, and the Science Advisory Board's review of the draft study plan.[20] Once identified, sources are classified as shown in Table 9.

Table 9. Classifications of information sources with examples. Once identified, existing literature and data sources are classified according to the following categories.

Source Classification	Examples
Peer-reviewed literature	Journal publications, reports, and white papers developed by federal and state agencies
Non-peer-reviewed literature	Non-peer-reviewed government documents; congressional documents and hearing proceedings; workshop proceedings; Ph.D. theses; non-peer-reviewed reports and white papers from industry, associations, and non-governmental organizations
Unpublished data	Online databases, personal communications, unpublished manuscripts, unpublished government data

Once sources are grouped into the categories shown in Table 9 above, assessment factors are used to further evaluate their merit. Five assessment factors are being used to evaluate the quality of existing data and information: soundness, applicability and utility, clarity and completeness, uncertainty and variability, and evaluation and review (US EPA, 2003a). These factors are described in more detail in Table 10.

[18] OnePetro is an online library of technical literature for the oil and gas exploration and production industry. It can be accessed at http://www.onepetro.org/.

[19] Thomson Reuters Web of Knowledge℠ is a research platform that provides access to objective content and powerful tools to search, track, measure, and collaborate in the sciences, social sciences, arts, and humanities. It can be accessed at http://wokinfo.com/.

[20] A list of literature recommended by the Science Advisory Board can be found on pages 29–34 of the Science Advisory Board's review of the draft Study Plan, available at http://yosemite.epa.gov/sab/sabproduct.nsf/0/2BC3CD632FCC0E99852578E2006DF890/$File/EPA-SAB-11-012-unsigned.pdf.

Table 10. Description of factors used to assess the quality of existing data and information compiled during the literature review. The assessment factors are identified in (US EPA, 2003a).

Factors	Description
Soundness	The extent to which the scientific and technical procedures, measures, methods, or models employed to generate the information are reasonable for, and consistent with, the intended application
Applicability and utility	The extent to which the information is relevant for the agency's intended use
Clarity and completeness	The degree of clarity and completeness with which the data, assumptions, methods, quality assurance, sponsoring organizations, and analyses employed to generate the information are documented
Uncertainty and variability	The extent to which the variability and uncertainty (quantitative and qualitative) in the information or in the procedures, measures, methods or models are evaluated and characterized
Evaluation and review	The extent of independent verification, validation, and peer review of the information or of the procedures, measures, methods, or models

Information included in the report of results will be drawn primarily from peer-reviewed publications. Peer-reviewed publications contain the most reliable information, although some portions of the report may contain compilations of data from a variety of sources and source classifications. Non-peer-reviewed and unpublished sources will not form the sole basis of any conclusions presented in the report of results. Generally, these sources will be used to support results presented from peer-reviewed work, enhance understanding based on peer-reviewed sources, identify promising ideas of investigation, and discuss further in-depth work needed.

The criteria in Table 10 are applied to all sources to ensure that the EPA is using high-quality data. In some cases, these data may not strictly meet the quality guidelines outlined in Table 10, though they still provide valuable information. Principal investigators on this project are responsible for deciding whether to include these data and providing all available background information in order to place these results in the appropriate context.

3.1.4. Status and Preliminary Data

The literature review is currently underway. Water acquisition, chemical mixing, and flowback and produced water are the only stages of the hydraulic fracturing water cycle for which specific updates are available at this time.

Water Acquisition. The water acquisition literature review is intended to complement the analysis of existing data on hydraulic fracturing fluid source water resources from nine service companies (see Section 3.3) and nine oil and gas operators (Section 3.4), as well as the analysis of existing data from FracFocus (Section 3.5). Work at this stage is directed at answering three secondary research questions:

- How much water is used in hydraulic fracturing operations, and what are the sources of this water?
- How might water withdrawals affect short- and long-term water availability in an area with hydraulic fracturing activity?

- What are the possible impacts of water withdrawals for hydraulic fracturing operations on local water quality?

To date, work has focused on the first question regarding the volumes and sources of water acquired for use in hydraulic fracturing. The literature review focuses on the major basins where hydraulic fracturing is prevalent in order to present a national perspective on water use. Hydrocarbon plays that will be highlighted include the Barnett, Eagle Ford, and Haynesville Shales in the South, the Bakken Shale in the Midwest, and the Marcellus and Utica Shales in the East.

The Barnett, Eagle Ford, and Haynesville Shales have undergone the most thorough analysis as reflected by the availability of peer-reviewed literature pertaining to the Texas oil and gas basins and to the water resources in the southern United States. The Bakken Shale has also been investigated extensively, although very little peer-reviewed literature was available for analysis as of July 2012. Instead, information on volumes and sources of water in the Bakken Shale comes largely from news articles. Water acquisition in the Marcellus and Utica Shales has not yet been analyzed, but water withdrawal data is expected to be available.

Chemical Mixing and Flowback and Produced Water. Existing scientific literature is being reviewed to identify how chemicals used in hydraulic fracturing fluids or present in hydraulic fracturing wastewaters may contaminate drinking water resources as a result of surface spills of these fluids. Relevant information from the literature review will help address the research questions listed below:

- If spills occur, how might hydraulic fracturing chemical additives contaminate drinking water resources?
- If spills occur, how might hydraulic fracturing wastewaters contaminate drinking water resources?

The EPA has identified chemicals for further review based on publicly available information on hazard and frequency of use. Tables 11 and 12 identify a subset of chemicals used in hydraulic fracturing fluids as reported to the US House of Representatives' Committee on Energy and Commerce by 14 hydraulic fracturing service companies as being used in hydraulic fracturing fluids between 2005 and 2009 (USHR, 2011). Table 11 lists chemicals that are known or suspected carcinogens, regulated by the Safe Drinking Water Act (SDWA), or listed as Clean Air Act hazardous air pollutants. The Committee included the hazardous air pollutant designation for listed chemicals because some may impact drinking water (e.g., methanol and ethylene glycol). Table 12 lists the chemical components appearing most often in over 2,500 hydraulic fracturing products used between 2005 and 2009, according to the information reported to the Committee.

Table 11. Chemicals identified by the US House of Representatives Committee on Energy and Commerce as known or suspected carcinogens, regulated under the Safe Drinking Water Act (SDWA) or classified as hazardous air pollutants (HAP) under the Clean Air Act. The number of products containing each chemical is also listed. These chemicals were reported by 14 hydraulic fracturing service companies to be in a total of 652 different products used between 2005 and 2009. Reproduced from USHR (2011).

Chemicals	Category	No. of Products
Methanol	HAP	342
Ethylene glycol	HAP	119
Naphthalene	Carcinogen, HAP	44
Xylene	SDWA, HAP	44
Hydrochloric acid	HAP	42
Toluene	SDWA, HAP	29
Ethylbenzene	SDWA, HAP	28
Diethanolamine	HAP	14
Formaldehyde	Carcinogen, HAP	12
Thiourea	Carcinogen	9
Benzyl chloride	Carcinogen, HAP	8
Cumene	HAP	6
Nitrilotriacetic acid	Carcinogen	6
Dimethyl formamide	HAP	5
Phenol	HAP	5
Benzene	Carcinogen, SDWA, HAP	3
Di (2-ethylhexyl) phthalate	Carcinogen, SDWA, HAP	3
Acrylamide	Carcinogen, SDWA, HAP	2
Hydrofluoric acid	HAP	2
Phthalic anhydride	HAP	2
Acetaldehyde	Carcinogen, HAP	1
Acetophenone	HAP	1
Copper	SDWA	1
Ethylene oxide	Carcinogen, HAP	1
Lead	Carcinogen, SDWA, HAP	1
Propylene oxide	Carcinogen, HAP	1
p-Xylene	HAP	1

Table 12. Chemical appearing most often in hydraulic fracturing in over 2,500 products reported by 14 hydraulic fracturing service companies as being used between 2005 and 2009. Reproduced from USHR (2011).

Chemical	No. of Products
Methanol	342
Isopropanol	274
Crystalline silica	207
2-Butoxyethanol	126
Ethylene glycol	119
Hydrotreated light petroleum distillates	89
Sodium hydroxide	80

Existing scientific literature is also being reviewed for the chemicals identified as part of the analytical method development research project (see Table 45 in Section 5.4). This table includes chemicals associated with injected hydraulic fracturing fluids and wastewater.

Literature searches have found papers describing impacts from spills of produced water (Healy et al., 2011; Healy et al., 2008), although the emphasis is often on ecosystem impacts rather than drinking water impacts. Produced water has the greatest number of literature publications for reported spills compared to hydraulic fracturing fluids and flowback, because produced water must be managed in both conventional and unconventional oil and gas production. Papers describing impacts from spills of produced water from conventional oil and gas production wells are being considered as part of the literature review because the chemical composition of flowback and produced water from hydraulically fractured formations is similar to that of conventional reservoirs (Hayes, 2009). Publications about impoundment leaks or other types of surface impoundment failures are also included within the scope of the flowback and produced water literature review.

Because some of the chemicals commonly used in hydraulic fracturing fluid are ubiquitous, a very large numbers of papers have been found. To narrow the scope, recent review papers on environmental impacts and other published summaries on transport of chemicals or classes of chemicals are being sought. Information on the chemicals listed in Tables 11, 12, and 45 has been collected primarily by searching peer-reviewed literature using keyword searches of major databases, including Web of Knowledge℠, Proquest,[21] and OnePetro. Review papers describing impacts from spills of hydraulic fracturing fluids containing benzene, toluene, ethylbenzene, and xylenes (Farhadian et al., 2008; Seagren and Becker, 2002; Seo et al., 2009); ethylene glycol (Staples et al., 2001); phenol (Van Schie and Young L.Y., 2000); surfactants (Scott and Jones, 2000; Sharma et al., 2009; Soares A. et al., 2008; Van Ginkel, 1996); and napthalenes (Haritash and Kaushik, 2009; Rogers et al., 2002) have been identified. Other sources of information include the Government Accountability Office report on federal research on produced water (US GAO, 2012); toxicological profiles from the Agency for Toxic Substances and Disease Registry, which often contain brief summaries of information on transport and transformation;[22] EPA software systems (US EPA, 2012b); and chemical reference handbooks (Howard, 1989; Howard et al., 1991; Montgomery, 2000). Specific discussion of abiotic transformations is included in some of these references, including the Agency for Toxic Substances and Disease Registry Toxicological Profiles, environmental organic chemistry references (Schwarzenbach et al., 2002), and review papers (Stangroom et al., 2010).

Chemical and physical properties of most of the organic chemicals listed in Tables 11 and 12 have been summarized, and the analysis is nearly complete. As more chemicals of interest are identified throughout the study, the number of chemicals may expand. Fewer publications exist for less

[21] ProQuest can be accessed at http://www.proquest.com.

[22] See, for example, pages 258–259 of ATSDR (2007).

common chemicals, however, and obtaining enough data to characterize these chemicals' potential to affect drinking water resources may not be feasible.

3.1.5. Next Steps

Next steps include completing the literature review for questions pertaining to sources, volumes, and impacts of large volume water withdrawals on local water quality and water availability. Further review of the water acquisition and quantity literature will specifically address the volumes and sources of water used in the Marcellus and Utica Shales. The literature review on chemical mixing and flowback and produced water for information that may answer the secondary research questions for those water stages will be completed. The EPA will also review relevant literature on all the remaining secondary research questions.

3.1.6. Quality Assurance Summary

The quality assurance project plan (QAPP) for the literature review, "Data and Literature Evaluation for the EPA's *Study of the Potential Impacts of Hydraulic Fracturing (HF) on Drinking Water Resources* (Version 0)," was approved on September 4, 2012 (US EPA, 2012f). Links to the all of the QAPPs are provided in Appendix C.

3.2. Spills Database Analysis

3.2.1. Relationship to the Study

The primary research questions for the chemical mixing and flowback and produced water stages of the hydraulic fracturing water cycle focus on the potential for hydraulic fracturing fluids and wastewaters to be spilled on the surface, possibly impacting nearby drinking water resources. This project searches various data sources in order to answer the research questions listed in Table 13.

Table 13. Secondary research questions addressed by reviewing existing databases that contain data relating to surface spills of hydraulic fracturing fluids and wastewater.

Water Cycle Stage	Applicable Research Questions
Chemical mixing	What is currently known about the frequency, severity, and causes of spills of hydraulic fracturing fluids and additives?
Flowback and produced water	What is currently known about the frequency, severity, and causes of spills of flowback and produced water?

3.2.2. Project Introduction

Hydraulic fracturing operations require large quantities of chemical additives, equipment, water, and vehicles, which may create risks of accidental releases, such as spills or leaks. Surface spills or releases can occur as a result of events such as tank ruptures, equipment or surface impoundment failures, overfills, vandalism, accidents, ground fires, or improper operations. Released fluids might flow into nearby surface water bodies or infiltrate into the soil and near-surface ground water, potentially reaching drinking water aquifers (NYSDEC, 2011).

Over the past few years, there have been numerous media reports of spills of hydraulic fracturing fluids and wastewater (US EPA, 2011e). While the media reports have highlighted specific surface spills of hydraulic fracturing fluids and wastewaters, the frequency and typical causes of these spills remain unclear. Additionally, these reports may tend to highlight severe spills and may not accurately reflect the distribution, number, and severity of spills across the country. The EPA is compiling information on surface spills of hydraulic fracturing fluids and wastewaters as reported in federal and state databases to assess the frequency, severity, and causes of spills associated with hydraulic fracturing. Hydraulic fracturing fluid and wastewater spill information was also collected from nine hydraulic fracturing service companies and nine oil and gas operators, as discussed in Sections 3.3 and 3.4, respectively. Together, these data are being used to describe spills of hydraulic fracturing fluids and wastewater and to identify factors that may lead to potential impacts on drinking water resources.

3.2.3. Research Approach

There is currently no national repository or database that contains spill data focusing primarily on hydraulic fracturing operations. In the United States, spills relating to oil and gas operations are reported to the National Response Center (NRC) and various state regulatory entities. For example, in Colorado, spills are reported to the Oil and Gas Conservation Commission, within the Department of Natural Resources, while in Texas, oil and gas related spills are reported to the Texas Railroad Commission and the Texas Commission on Environmental Quality, depending on which agency has jurisdiction. The EPA has identified one federal database and databases in five states for review, as listed in Table 14. The NRC database was selected because it is the only nationwide source of information on releases of hazardous substances and oil. Spill databases from Colorado, New Mexico, Pennsylvania, Texas, and Wyoming were chosen for further consideration due to the large number of hydraulically fractured oil and gas wells found in those states.[23]

Table 14. Oil and gas-related spill databases used to compile information on hydraulic fracturing-related incidents.

Source	Website
National Response Center Freedom of Information Act data	http://www.nrc.uscg.mil/foia.html
Colorado Oil and Gas Information System	http://www.cogcc.state.co.us
New Mexico Energy, Minerals and Natural Resources Department	https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting/Data/Incidents/Spills.aspx http://www.emnrd.state.nm.us/ocd/Statistics.html
Pennsylvania Department of Environmental Protection Compliance Reporting Database	http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/OG_Compliance
Texas Railroad Commission and Texas Commission on Environmental Quality	Consolidated Compliance and Enforcement Data System (not publicly available online)
Wyoming Department of Environmental Quality Water Quality Enforcement Actions	http://deq.state.wy.us/out/WQenforcementactions.htm

Each of the publicly available databases identified in Table 14 has been searched for spill incidents related to hydraulic fracturing operations. The search timeframe is limited to incidents between January 1, 2006, and April 30, 2012, in order to encompass the increase in hydraulic fracturing

[23] Based on data provided by nine hydraulic fracturing service companies of oil and gas wells fractured between 2009 and 2010. See Figure 10 in Section 3.3.

activity seen during that period. To the extent that data are publicly available, electronically accessible, and readily searchable for spill-related data, the following information is being compiled about specific hydraulic fracturing-related spill incidents:

- Data source
- Location
- Chemicals/products spilled
- Estimated/reported volume of spill
- Cause of spill
- Reported impact to nearby water resources
- Proximity of the spill to the well or well pad

The information obtained from the NRC and state databases is being reviewed with information received in response to the EPA's September 2010 information request to nine hydraulic fracturing service companies (see Section 3.3) and the EPA's August 2011 information request to nine oil and gas operators (Section 3.4). The resulting list of unique spill incidents is being queried to identify common causes of hydraulic fracturing-related spills, chemicals spilled, the ranges of volumes spilled, and the potential impacts of these spills to drinking water sources. Because the main focus of this study is to identify hydraulic fracturing-related spills on the well pad that may impact drinking water resources, the following topics are not included in the scope of this project:

- Transportation-related spills (except when tanker trucks act as mobile portable storage containers for chemicals, products, and hydraulic fracturing wastewater used on drilling sites)
- Drilling mud spills
- Air releases
- Spills associated with disposal through underground injection control wells
- Erosion and sediment control issues
- Spill drills and exercise events (per NRC data)
- Well construction and permitting violations
- Leaks from pipes transporting flowback and produced water from one site to another for reuse

3.2.4. Status and Preliminary Data

The EPA has initiated work on all publicly available databases listed in Table 14. This section summarizes the type of information available in each database and lists the criteria being used to search each database.

National Response Center Freedom of Information Act Data. This database contains nationwide data on releases of hazardous substances and oil that trigger the federal notification requirements under several laws. The NRC is the sole federal point of contact for reporting of all hazardous substances releases and oil spills. Its information comes from people who arrive on the scene or discover a spell, then call the NRC hotline or submit a Web-based report form. The information collected by the NRC during the initial notification call may include the suspected responsible party; the incident location by county, state, and nearest city; the released material and volume or quantity released; and a description of the incident, incident causes, affected media, initial known damages, and remedial actions taken. This information is often based on the estimates made by persons responding to a spill and may be incomplete. More accurate information may be available once a response is complete, but this database is not updated with such information.

The data fields that can be used to query the NRC database are listed in Table 15. Many of these fields only allow searches from a fixed (i.e., drop-down) list, although several of the data fields are open to any input. None of the search terms in the fixed lists are specific to hydraulic fracturing or oil and gas exploration and production.

Table 15. Data fields available in the NRC Freedom of Information Act database. "Fixed list data fields" contain a fixed list of search terms form which the user can choose. "Open data fields" can receive any input from the user.

Fixed List Data Fields	Open Data Fields
Type of call	NRC report number
Incident date range	Nearest city
State	Suspected responsible company
County	Material name
Incident type	
Incident cause	
Medium affected	

Given the query restrictions, broad searches are being conducted using the listed responsible company, material name, and incident date range fields (i.e., leaving other fields blank).

The resulting spills are being examined to determine their relevance to this study. Since the database includes only initial incident reports, information is frequently missing or estimated, such as total volume spilled. Also, misspellings in the reports or the use of different vocabulary can cause the search engine to miss relevant incidents.

Colorado. The Colorado Oil and Gas Conservation Commission gathers data regarding pits, spills/releases, and complaints relating to oil and gas exploration and production. Oil and gas operators are required to report spills and releases that occur as a result of oil and gas operations, in accordance with Colorado Oil and Gas Conservation Commission Rule 906 (COGCC, 2011). Reported information is entered into the Colorado Oil and Gas Information System Inspection/Incident Database. Each report documents the type of facility, volume spilled and/or recovered, ground water impacts, depth to shallowest ground water, surface water impacts, distance to nearest surface water, cause of spill, and a detailed description of the incident. The database is searchable by API number,[24] complainant, operator, facility/lease, location, remediation project number, and document number. Since there is no searchable data field in the database to indicate whether the spill is related to hydraulic fracturing, the database was queried for all spill/release reports. Only reports dated from January 1, 2006, to April 30, 2012, were selected for further review. This search returned over 2,500 reports that are currently being evaluated to identify incidents related to hydraulic fracturing activities.

New Mexico. The Oil Conservation Division of the State of New Mexico Energy, Minerals and Natural Resources Department tracks information, in two separate databases, on both spill incidents and incidents where liquids in pits have contaminated ground water. Release Notification and Corrective Action forms are submitted to the Oil Conservation Divisions District offices. Spills can be reported by industry representatives or state agency personnel.

The spills database is searchable by facility and well names, incident type, operator, location, lease type, spilled material, spill cause, spill source, and the spill referrer (person who reported the incident). The database was initially searched using the spill material, spill cause, and spill source data fields. Each of these fields can only be searched using the preset search terms listed in Table 16. The initial search was conducted using the search terms in bold in Table 16. The EPA is currently examining the resulting list of spills to determine their relevancy to this study and is considering running additional queries to collect more information.

[24] The API (American Petroleum Institute) number is a unique, permanent, numeric identifier assigned to each well drilled for oil and gas in the United States.

Table 16. Preset search terms available for the spill material, spill cause, and spill source data fields in the New Mexico Oil Conservation Division Spills Database. Terms in bold have been searched.

Spill Material	Spill Cause	Spill Source
All	All	All
Acid	**Blowout**	Coupling
Brine water	Corrosion	Gas compression station
B.S. & W (basic sediment & water)	Equipment failure	Dump line
Chemical (specify)	Fire	Motor
Condensate	Freeze	Flowline—injection
Diesel	Human error	Flowline—production
Drilling mud/fluid	Lightning	**Frac tank**
Glycol	Other	Fitting
Gasoline	Normal operations	Injection header
Gelled brine (frac fluid)	Vandalism	Other (specify)
Hydrogen sulfate	Vehicular accident	**Pit (specify)**
Crude oil		Pipeline (any)
Motor oil		Production tank
Natural gas (methane)		Pump
Natural gas liquids		Separator
Lube oil		Transport
Other (specify)		Unknown
Produced water		Valve
Unknown		Well
		Water tank

The database containing information regarding contamination of ground water due to pits tracks only the current company, facility name, tracking number, county, location, and status of the contamination incidents. Details regarding the contamination incident and the relation of the event to hydraulic fracturing are not included. Additional research is needed to determine if the pit information is related to hydraulic fracturing.

Pennsylvania. The Pennsylvania Department of Environmental Protection's Compliance Reporting Database provides information on oil and gas inspections, violations, enforcement actions, and penalties assessed and collected. Users can search the database according to the following fixed-variable data fields: county, municipality, date inspected, operator, Marcellus only,[25] inspections with violations only, and resolved violations only.

Table 17 displays the total number of incidents retrieved for four different queries, all using a date range of January 1, 2006, to April 30, 2012.

[25] This data field was recently changed to "unconventional only" (last accessed July 6, 2012).

Table 17. Total number of incidents retrieved from the Pennsylvania Department of Environmental Protection's Compliance Reporting Database by varying inputs in the "Marcellus only" and inspections with "violations only data fields." In all cases, "no" was entered in the "resolved violations only" field.

Marcellus Only	Inspections with Violations Only	Total Number of Incidents Retrieved
Yes	No	25,687
Yes	Yes	4,319
No	Yes	18,700
No	No	Unknown*

* Error message received when formatting results of this query.

The queries shown in Table 17 returned information collected during inspections that found violations and/or when spills are reported. An incident or inspection may have multiple violations, leading to a large total number of violations retrieved from the database. The EPA's initial effort focused on the query that returned the fewest violations, which totaled 4,319 inspections with violations specific to the Marcellus Shale region. Inspection and violation comment fields for each incident are being reviewed to identify incidents related to hydraulic fracturing activities.

Texas. Representatives of the Railroad Commission of Texas, the Texas Commission on Environmental Quality, and the Texas General Land Office have confirmed that there is no central database in Texas on hydraulic fracturing-related spills. In Texas, a memorandum of understanding between the Railroad Commission and Commission on Environmental Quality identifies the jurisdiction of these agencies over waste materials resulting from exploring, developing, producing, and refining oil and gas. Pursuant to this understanding, oil and gas operators are required to report spills to the Railroad Commission, which maintains a publicly available database of spills of petroleum, oil, and condensate. The EPA has reviewed this database and determined that it does not include chemical spills; most of the spills reported in the database are crude oil spills. Therefore, there will be no further analysis of this database.

The Commission on Environmental Quality is Texas' lead agency in responding to spills of all hazardous substances that may cause pollution or lower air quality pursuant to the Texas Hazardous Substances Spill Prevention and Control Act (Texas Water Code §26.261). The Commission on Environmental Quality may generate an investigation, inspection, or complaint report in response to emergency spill notifications. These reports are submitted to the state's Consolidated Compliance and Enforcement Data System. However, the investigation and inspection reports in this database are not available electronically on the Texas Commission on Environmental Quality's website or at their Central Files Room.

Other attempts were made to obtain information on potential ground water contamination incidents related to hydraulic fracturing by examining the Joint Groundwater Monitoring and Contamination Reports prepared by the Texas Groundwater Protection Committee; this effort was unsuccessful in getting the relevant incident details. The abovementioned searches for hydraulic fracturing spill-related data may not be an exhaustive investigation of all available information from Texas' state agencies or organizations, but other publicly available sources of information have not been located at this time.

Wyoming. The Wyoming Department of Environmental Quality maintains a publicly available database of water quality enforcement actions. This database includes reports of water quality violations categorized by the year they occurred, from 2006 to 2012. None of the reports differentiate between hydraulic fracturing-related incidents and those due to other stages of oil and gas development. Many of the oil and gas-related violations were for CBM produced water discharges, such as to surface water. Due to the lack of information to differentiate between hydraulic fracturing-related incidents and other oil and gas-related incidents, there will be no further analysis of this dataset.

The spills database analysis has several important limitations:

- *Potential underreporting.* This affects the EPA's ability to assess the number or frequency of hydraulic fracturing-related spill incidents, since it is likely that some spills are not reported to the NRC or state agencies.
- *Variation in reporting requirements for different sources.* This makes it difficult to categorize reported spills as hydraulic fracturing-related and to comprehensively identify the causes, chemical identity, and volumes of hydraulic fracturing-related spills.
- *The lack of electronic accessibility of some state-reported data on oil and gas-related spills and emergency responses.* This also significantly impacts the comprehensiveness of the available information.

3.2.5. Next Steps

As noted, the EPA is reviewing the list of spill incidents generated by searching the NRC, Colorado, New Mexico, and Pennsylvania databases to identify incidents related to hydraulic fracturing activities. Spill incidents identified through this review will be combined with data received from nine hydraulic fracturing service companies (see Section 3.3) and nine oil and gas operators (Section 3.4) to create a master database of hydraulic fracturing-related spills from these sources. The compiled information will be examined to identify, where possible, common causes of hydraulic fracturing-related spills, chemicals spilled, and ranges of volumes spilled. Specific steps will then include:

- Creating a reference table of information gathered from all incidences determined to be related to hydraulic fracturing.
- Reviewing this reference table for trends in the causes and volumes of hydraulic fracturing-related spills.

3.2.6. Quality Assurance Summary

The QAPP for the analysis of publicly available information on surface spills related to hydraulic fracturing, "Hydraulic Fracturing (HF) Surface Spills Data Analysis (Version 1)," was approved on August 6, 2012 (US EPA, 2012l). The project underwent a technical systems audit (TSA) by the designated EPA QA Manager on August 27, 2012. The methods and products being developed under the project adhered to the approved QAPP, and no corrective actions were identified.

3.3. Service Company Analysis

3.3.1. Relationship to the Study

The EPA asked nine hydraulic fracturing service companies for information about hydraulic fracturing operations conducted from 2005 to 2010. The data are being analyzed for information that can be used to inform answers to the research questions in Table 18.

Table 18. Secondary research questions addressed by analyzing data received from nine hydraulic fracturing service companies.

Water Cycle Stage	Applicable Research Questions
Water acquisition	• How much water is used in hydraulic fracturing operations, and what are the sources of this water?
Chemical mixing	• What is currently known about the frequency, severity, and causes of spills of hydraulic fracturing fluids and additives? • What are the identities and volumes of chemicals used in hydraulic fracturing fluids, and how might this composition vary at a given site and across the country?
Well injection	• How effective are current well construction practices at containing gases and fluids before, during, and after fracturing? • Can subsurface migration of fluids or gases to drinking water resources occur and what local geologic or man-made features may allow this? • How might hydraulic fracturing fluids change the fate and transport of substances in the subsurface through geochemical interactions?
Flowback and produced water	• What is currently known about the frequency, severity, and causes of spills of flowback and produced water? • What is the composition of hydraulic fracturing wastewaters, and what factors might influence this composition?

3.3.2. Project Introduction

Hydraulic fracturing is typically performed by a service company under a contract with the oil or gas production well operator. The service companies possess detailed information regarding the implementation of hydraulic fracturing, from design through fracturing. In September 2010, the EPA requested information from nine companies on the chemical composition of hydraulic fracturing fluids used from 2005 to 2010, standard operating procedures (SOPs), impacts of chemicals on human health and the environment, and the locations of oil and gas wells hydraulically fractured in 2009 and 2010. The EPA is analyzing the information received from the service companies to better understand current hydraulic fracturing operating practices and to answer the research questions listed above.

Service Companies Selected. Nine service companies received the information request: BJ Services Company, Complete Production Services, Halliburton, Key Energy Services, Patterson-UTI Energy, RPC, Schlumberger, Superior Well Services, and Weatherford International. These companies reflect a range of industry market share and variation in company size. The EPA estimated that BJ Services Company, Halliburton, and Schlumberger performed approximately 95% of hydraulic fracturing services in the United States in 2003 (US EPA, 2004b), and the three companies reported the highest annual revenues for 2009 of the nine companies selected for the information request.[26] The remaining six companies represent mid-sized and small companies performing hydraulic fracturing services between 2005 and 2009.[27] Table 19 shows the annual revenue, number of employees, and company services reported by the companies to the US Securities and Exchange Commission in the 2009 Form 10-K.

Table 19. Annual revenue and approximate number of employees for the nine service companies selected to receive the EPA's September 2010 information request. The companies reflect a range of industry market share and company sizes. Information was obtained from Form 10-K, filed with the US Securities and Exchange Commission in 2009.

Company	Annual Revenue for 2009 (Millions)	Number of Employees (Approximate)
BJ Services Company*	$4,122	14,400
Complete Production Services	$1,056	5,200
Halliburton	$14,675	51,000
Key Energy Services	$1,079	8,100
Patterson-UTI Energy	$782	4,200
RPC	$588	2,000
Schlumberger	$22,702	77,000
Superior Well Services	$399	1,400
Weatherford International	$8,827	52,000

* BJ Services reports on a fiscal year calendar ending on September 30.

Three of the nine service companies that reported information to the EPA were acquired by other companies since 2010. Baker Hughes completed the purchase of BJ Services Company in April 2010, Patterson-UTI Energy purchased Key Energy Services in October 2010, and Superior Well Services acquired Complete Production Services in February 2012.

3.3.3. Research Approach

The EPA received responses to the September 2010 information request from each of the nine service companies. Data and information relevant to the research questions posed above were collected and organized in Microsoft Excel spreadsheets and Microsoft Access databases. Each company reported information in various organizational formats and using different descriptive terms; therefore, the EPA has put all nine datasets into a consistent format for analysis and resolving any issues associated with terminology, data gaps, or inconsistencies. This selection of information serves as the basis for targeted queries and data summaries described below. The queries and data summaries have been designed to answer the secondary research questions listed in Table 18.

Much of the data and information received by the EPA was claimed to be confidential business information (CBI) under the Toxic Substances Control Act (TSCA). Five of the nine companies,

[26] Information was obtained from the 2009 Form 10-K, filed with the US Securities and Exchange Commission.

[27] Annual revenue and number of employees were used as indicators of company size.

however, also provided non-confidential information.[28] Because the majority of the information has been claimed as CBI, the analyses described below are being conducted in accordance with the procedures outlined in the EPA's TSCA CBI Protection Manual (US EPA, 2003b). All results are treated as CBI until determinations are made or until masking has been done to prevent disclosure of CBI information.

Summary of Service Company Operations. The EPA is using information provided by the companies to write a narrative description of the range of their operations, which includes information on the role of the service companies in each stage of the hydraulic fracturing water cycle.

Information has been compiled on the number and location of wells hydraulically fractured by the nine service companies between September 2009 and October 2010, resulting in a map that displays the number of wells fractured per county as reported by the companies. This information is intended to illustrate the intensity and geographic distribution of hydraulic fracturing activities by these companies.

Water Acquisition. The following information from the service company data on volumes, quality, and sources of water used in hydraulic fracturing fluids is being summarized and will include:

- *Water use by shale play*. The range of water volumes used based on the shale play in which the well is located. (The companies did not provide information on geologic formations other than shale.)
- *Procedures and considerations relating to water acquisition.* Summary of any SOPs, water quality requirements, water source preferences, and decision processes described in the submissions from the nine service companies.

Chemical Mixing. The following information collected from the service companies is being assembled to identify the composition of different hydraulic fracturing fluid formulations and the factors that influence formulation composition:

- Chemical name
- Chemical formula
- Chemical Abstracts Service Registration Number (CASRN)
- Material Safety Data Sheets (MSDSs) for each fluid product
- Concentration of each chemical in each fluid product
- Manufacturer of each product and chemical
- Purpose and use of each chemical in each fluid product

[28] The non-confidential information is available on the federal under docket number EPA-HQ-ORD-2010-0674 or via http://www.regulations.gov/#!searchResults;rpp=10;po=0;s=epa-hq-ord-2010-0674.

For the purposes of the analysis, the EPA defines a "product" as an additive composed of a single chemical or several chemicals. A "chemical" is an individual chemical included in a product. A "fluid formulation" is the entire suite of products and carrier fluid injected into a well during hydraulic fracturing. The following information from the service company data on chemicals, products, and fluid formulations is being summarized:

- *Formulations, products, and product function.* The formulations reported by the nine service companies and the number and types of products used in those formulations.
- *Products, chemicals in those products and concentrations, and manufacturer of each product.* The chemicals used in each product may be used in conjunction with the formulations data (described in the previous bullet) to discern the chemicals used in each formulation. The manufacturer of each product will also be included.
- *Number of products reported for a given product function and the frequency with which a product function is reported in the formulations data.* The product function with the greatest number of products and the product function that is most often used in formulations.
- *Number of products and chemicals for each type of formulation.* The chemicals and products for various types of formulations and a description of the average number of products and chemicals for each formulation type, as well as the sample size for each population and common product functions for each formulation type.
- *Typical loadings for each group of products of a given product function and for each fluid formulation type.* The typical proportion of a product in a formulation. Typical loading values (e.g., gallons per thousand gallons) indicate an amount or volume of a product added to a volume of fracturing fluids rather than an accurate representation of the concentration of a particular product or the chemical constituents of a product in a fluid formulation.

Information provided by the companies relating to surface spills of hydraulic fracturing fluids and chemicals has been compiled, resulting in a table of specific spill incidences. The table includes information on the location, composition, volume, cause, and any reported impacts of each spill. This information will be used in the larger analysis of surface spills reported in federal and state databases (Section 3.2).

Well Injection. The EPA requested information regarding the hydraulic fracturing service companies' procedures for establishing well integrity, procedures used during well injections, and response plans to address unexpected circumstances (e.g., unexpected pressure changes during injection). Information provided by the companies will be used to write a narrative description of the range of operations conducted by this sample of service companies.

Flowback and Produced Water. Although this information was not requested, the EPA received some documents and information that referenced flowback and produced water, including policies, practices, and procedures employed by companies to determine estimated volumes and management options. The EPA has reviewed this information as well as information relevant to the frequency, severity, and causes of flowback and produced water spills and the composition of hydraulic fracturing wastewaters. The outputs of the analysis will include the following:

- *Reported spills of flowback and produced water.* Information on the composition of the fluid spilled, the volume spilled, the reported cause of the spill, and any reported impacts to nearby water resources. This information will be integrated into the larger analysis of surface spills reported in federal and state databases (see Section 3.2).
- *Reported compositions of hydraulic fracturing wastewater.* Information on the chemical and physical properties of hydraulic fracturing wastewater, such as the identities of analytes of interest and reported concentration ranges. To the extent possible, this information will be organized according to geologic and geographic location as well as time after fluid injection.
- *Flowback and produced water management.* Where possible, information about the role of hydraulic fracturing service companies in handling flowback and produced water will be described.

3.3.4. Status and Preliminary Data

Preliminary data analyses of service company operations, water acquisition, chemical mixing, and flowback and produced water has been completed and the analysis of well injection information has begun. The EPA has met with representatives from each of the nine hydraulic fracturing service companies to discuss their responses to the September 2010 information request. Information gathered during these meetings has been used to inform the data analysis and to ensure that confidential information is protected. As of September 2012, the EPA continues to clarify the information reported and to work with the nine hydraulic fracturing service companies to release information originally designated as CBI without compromising trade secrets.

Service Company Operations. As a group, the nine service companies reported that they hydraulically fractured 24,925 wells in the United States in 2009 and 2010. The companies reported the number of wells per county, which is displayed for all companies in Figure 10.

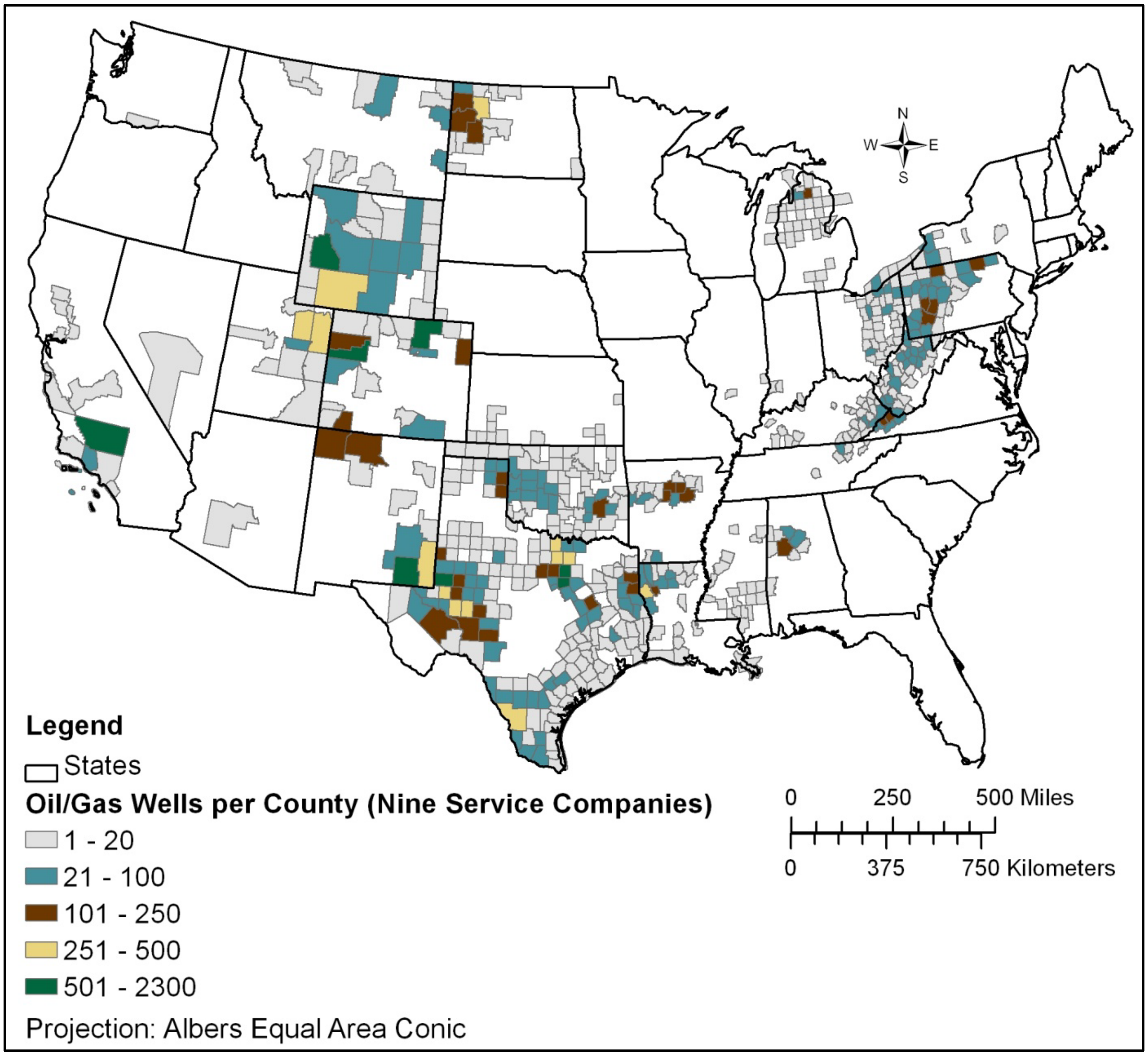

Figure 10. Locations of oil and gas production wells hydraulically fractured between September 2009 and October 2010. The information request to service companies (September 2010) resulted in county-scale locations for 24,925 wells. The service company wells represented in this map include only 24,879 wells because the EPA did not receive locational information for 46 of the 24,925 reported wells. (ESRI, 2010a, b; US EPA, 2011a)

Chemical Mixing. The service companies reported a total of 114 example formulations and 1,858 unique producets, which consist of 677 unique chemicals, used by the service companies between September 2005 and 2010.[29] Table 20 shows the number of formulations, products, and chemicals reported by each of the nine service companies; the totals for products and chemical constituents in Table 20 reflect use by multiple companies and are therefore greater than the sum of unique products and chemical constituents. The formulations reported to the EPA are not comprehensive, as each service company chose them as examples of the fluids they use.

[29] Products and chemical constituents noted here are unique and may have been reported multiple times by the service companies.

Table 20. Formulations, products, and chemicals reported as used or distributed by the nine service companies between September 2005 and September 2010.

Company	Formulations	Products*	Chemical Constituents[†]
BJ Services	37	401	118
Key Energy Services	16	180	119
Halliburton	15	450	304
RPC	13	182	128
Schlumberger	11	110	61
Patterson-UTI Energy	10	67	67
Weatherford International	6	214	180
Complete Production Services	3	122	92
Superior Well Services	3	312	117

* Companies reported examples of formulations, which did not contain all of the products reported to the EPA.
[†] Not all products have reported chemicals.

Non-confidential hydraulic fracturing chemicals reported by the companies appear in Appendix A, along with chemicals reported from publicly available sources.

Well Injection. Seven service companies reported 231 protocols to the EPA. The protocols describe the procedures used by the companies for many aspects of field and laboratory work, including site and infrastructure planning, chemical mixing and design of fracturing fluid formulations, health and safety practices, well construction, and hydraulic fracturing. The EPA is analyzing the information to assess how hydraulic fracturing service companies use SOPs, to better understand how well integrity is established prior to fracturing, and to evaluate procedures used during well injection.

Flowback and Produced Water. Data provided by the companies indicate that the company conducting the fracturing is often not the same company that manages the flowback process. Five of the companies responded that they do not provide flowback services, although one of these companies provides analytical support to operators for the testing of flowback water for potential reuse. Two of the nine stated that they provide flowback services independent of their hydraulic fracturing services. For another two companies, the EPA received no information clearly describing role regarding flowback services. Only one company provided detailed information on flowback management.

3.3.5. Next Steps

All analyses will undergo a QA review before being compiled in a final report. The EPA will continue to work with each of the nine companies to determine how best to summarize the results so that CBI is protected while providing information in a transparent manner.

3.3.6. Quality Assurance Summary

The QAPP for the analysis of data received from nine service companies, "Analysis of Data Received from Nine Hydraulic Fracturing (HF) Service Companies (Version 1)," was approved on August 1, 2012 (US EPA, 2012h). A TSA on the work was conducted by designated EPA QA Manager on August 28, 2012, to review the methods being used and work products being developed with the data. The work accurately reflected what is described in the QAPP, and no corrective actions were identified. In addition, the EPA's contractor, Eastern Research Group, has been involved with collecting and compiling data submitted from the nine hydraulic fracturing service companies. Eastern Research Group's QAPP was approved on January 19, 2011 (Eastern Research Group Inc., 2011).

3.4. Well File Review

3.4.1. Relationship to the Study

The well file review provides an opportunity to assess well construction and hydraulic fracturing operations, as reported by the companies that own and operate oil and gas production wells. Results from the review will inform answers to the secondary research questions listed in Table 21.

Table 21. Secondary research questions addressed by the well file review research project.

Water Cycle Stage	Applicable Research Questions
Water acquisition	• How much water is used in hydraulic fracturing operations, and what are the sources of this water?
Chemical mixing	• What is currently known about the frequency, severity, and causes of spills of hydraulic fracturing fluids and additives? • What are the identities and volumes of chemicals used in hydraulic fracturing fluids, and how might this composition vary at a given site and across the country? • If spills occur, how might hydraulic fracturing chemical additives contaminate drinking water resources?
Well injection	• How effective are current well construction practices at containing gases and fluids before, during, and after fracturing? • Can subsurface migration of fluids and gases to drinking water resources occur and what local geologic or man-made features may allow this?
Flowback and produced water	• What is currently known about the frequency, severity, and causes of spills of flowback and produced water? • What is the composition of hydraulic fracturing wastewaters, and what factors might influence this composition? • If spills occur, how might hydraulic fracturing wastewater contaminate drinking water resources?
Wastewater treatment and waste disposal	• What are the common treatment and disposal methods for hydraulic fracturing wastewaters, and where are these methods practiced?

3.4.2. Project Introduction

The process of planning, designing, permitting, drilling, completing, and operating oil and gas wells involves many steps, all of which are ultimately controlled by the company that owns or operates the well, referred to as the "operator." Assisting the operator are service companies that provide specialty services, such as seismic surveys, lease acquisition, road and pad building, well drilling, logging, cementing, hydraulic fracturing, water and waste hauling, and disposal. Some operators can perform some of these services on their own and some rely exclusively on service companies.

During the development and production of oil and gas wells, operators receive documentation from service companies about site preparation and characteristics, well design and construction, hydraulic fracturing, oil and gas production, and waste management. Operators typically maintain much of this information in an organized file, which cumulatively represents the history of the well. The EPA refers to this file as a "well file." Some of the information in a well file may be required by law to be reported to state oil and gas agencies, and some of the information may be considered CBI by the operator.

For this project, the EPA is scrutinizing actual well files from hydraulic fracturing operations in different geographic areas that are operated by companies of various sizes. These wells include vertical, horizontal, and deviated wells that produce oil, gas, or both from differing geological environments. This review is providing information that can be used to identify practices that may impact drinking water resources**.**

3.4.3. Research Approach

While a portion of the data needed for this project is reported to state oil and gas agencies, the complete dataset is available only in the well files compiled by oil and gas operators.[30] Further, different states have different reporting requirements. As a result, the EPA selected 350 well identifiers believed to represent oil and gas production wells hydraulically fractured by the nine hydraulic fracturing service companies and requested the corresponding well files from operators associated with those wells.[31] This section describes the process used by the EPA to select well files for review, the information requested, and the planned analyses.

Well File Selection. The EPA used a list of hydraulically fractured oil and gas wells provided to the agency by the nine hydraulic fracturing service companies (referred to hereafter as the "service company well list") to select 350 specific well identifiers associated with nine oil and gas operators.[32] The service company well list obtained by the EPA contains 24,925 well identifiers associated with wells that were reported to have been hydraulically fractured between September 2009 and October 2010 (Figure 10) and identifies 1,146 oil and gas operators. This compiled list includes, for each well, a well identifier, the operator's name, and the well's state and county location.

Counties containing the 24,925 well identifiers were grouped into four geographic regions according to a May 9, 2011, map of current and prospective shale gas plays within the lower 48 states (US EIA, 2011c).[33] If any portion of a county was within one of the shale gas plays defined on the map, the entire county was assigned to that shale play and the corresponding geographic region. The four regions—East, South, West, and Other—are shown in Figure 11 with the corresponding number of wells in each region. Counties outside the shale gas plays were grouped

[30] The EPA analyzed several state oil and gas agency websites and estimated that it would find less than 15% of the necessary data from websites to answer the research questions.

[31] Oil and gas production wells are generally assigned API numbers by state oil and gas agencies, a unique 10-digit number. Wells may also be commonly identified by a well name that is designated by the operator. The EPA considers both of these to be well identifiers.

[32] The EPA used the service company well list because it is unaware of the existence of a single list showing all oil and gas production wells in the United States, their operators, and whether each well has been hydraulically fractured.

[33] Wells within a designated shale play on the map are not guaranteed to be producing from that shale; they could be producing from rock formations within the same stratigraphic column.

into the Other region, which includes areas where oil and gas is produced from a variety of rock formations.[34] This grouping process allowed the EPA to select wells that reflect the geographic distribution of hydraulically fractured oil and gas wells.

A list of operators and their corresponding total well count was sorted by well count from highest to lowest. Operators with fewer than 10 well identifiers were removed, resulting in a final list of 266 operators and 22,573 wells. The resulting operators were categorized as “large,” “medium,” or “small.” Large operators were defined as those that accounted for the top 50% of the well identifiers on the list, medium operators for the next 25% and small operators for the last 25%. As a result, there were 17 large operators, 86 medium operators, and 163 small operators. To ensure that the final selected well identifiers would have geographic diversity among large operators, each large operator was assigned to one geographic region that contained a large number of its well identifiers.

One large operator was randomly chosen from each of the regions (i.e., one large operator from each of the East, South, West, and Other regions), for a total of four large operators. Two medium operators and three small operators were also chosen, with no preference for geographic region. This resulted in the selection of nine operators: Clayton Williams Energy, ConocoPhillips, EQT Production, Hogback Exploration, Laramie Energy, MDS Energy, Noble Energy, SandRidge Energy, and Williams Production.

[34] Forty-six well identifiers had unknown counties and have been included in the Other region for the purposes of this analysis.

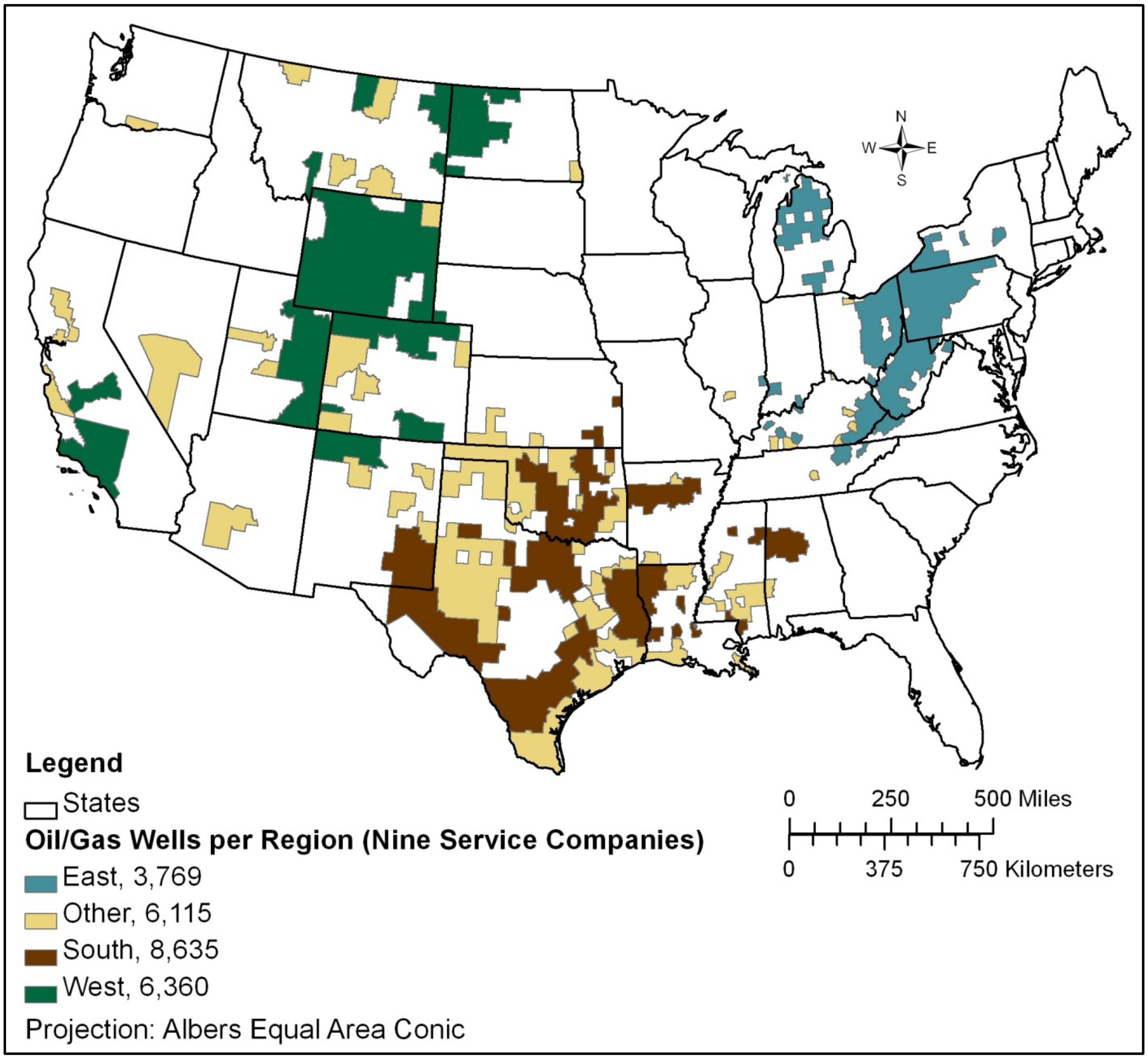

Figure 11. Locations of oil and gas production wells hydraulically fractured from September 2009 through October 2010. The information request to service companies (September 2010) resulted in county-scale locations for 24,925 wells. The service company wells are represented above as regional well summaries and summarize only 24,879 wells because the EPA did not have locational information for 46 of the 24,925 reported wells. (ESRI, 2010a, b; US EPA, 2011a)

The nine operators were associated with 2,455 well identifiers. The EPA initially chose 400 of those 2,455 well identifiers to request the associated well files for its analysis. The selection of 400 well identifiers required balancing goals of maximizing the geographic diversity of wells and maximizing the precision of any forthcoming statistical estimates. The well identifiers were chosen using an optimization algorithm that evaluated the statistical precision given different allocations across operating company/shale play combinations. The algorithm identified a solution given four constraints:

- Select all well identifiers for the three small operators whose total number of well identifiers was fewer than 35. For all other operators, keep the number of selected well identifiers between 35 and 77.
- Have at least two well identifiers (or one if there is only one) from each combination of a large operator and geographic region.
- Keep the regional distribution of sampled well identifiers close to the regional distribution of all 24,925 well identifiers on the initial service company well list.
- Keep the expected sampling variance due to unequal weights relatively small.

Due to resource and time constraints, the EPA subsequently decided to review 350 well files, so 50 of the 400 selected well identifiers were randomly removed. This sample size is large enough to be considered reasonably representative of the total number of wells hydraulically fractured by the nine service companies in the United States during the specified time period.

Data Requested. An information request letter was sent in August 2011 to the nine operators identified above, asking for 24 distinct items organized into five topic areas: (1) geologic maps and cross sections; (2) drilling and completion information; (3) water quality, volume, and disposition; (4) hydraulic fracturing; and (5) environmental releases.[35] Table 22 shows the potential relationship between the five topic areas and the stages of the hydraulic fracturing water cycle.

Table 22. The potential relationship between the topic areas in the information request and the stages of the hydraulic fracturing water cycle.

Water Cycle Stage	Information Request Topic Areas				
	Geologic Maps and Cross Sections	Drilling and Completion Information	Water Quality, Volume, and Disposition	Hydraulic Fracturing	Environmental Releases
Water acquisition			✓	✓	
Chemical mixing		✓	✓	✓	✓
Well injection	✓	✓	✓	✓	✓
Flowback and produced water			✓	✓	✓
Wastewater treatment and waste disposal			✓	✓	

Well File Review and Analysis. The EPA received responses to the August 2011 information request from each of the nine operators. Data and information contained in the well files is being extracted from individual well files and compiled in a single Microsoft Access database. All data in the database are linked by the well's API number; this process is described in more detail in the QAPP for this research project (US EPA, 2012j).

[35] See the text of the information request for the specific items requested under each topic area. The information request can be found at http://www.epa.gov/hfstudy/August_2011_request_letter.pdf.

Information in the database is being used to design queries that will inform answers to the research questions listed in Table 21. Examples of queries being designed include:

- What sources and volumes of water are used for hydraulic fracturing fluids?
- How many well files contain reports of chemicals spilled during hydraulic fracturing, and do the reports show whether the spills led to any impacts to drinking water resources?
- How many wells have poor cement bonds immediately above the uppermost depth being hydraulically fractured? This may indicate that the cement sheath designed to isolate the target zone being stimulated may fail, potentially leading to gas and fluid migration up the wellbore.
- How many well files contain reports of flowback or produced water spilled, and do the reports show whether the spills lead to any impacts to drinking water resources?
- What are the reported treatment and/or disposal methods for the wastewater generated from hydraulic fracturing?

3.4.4. Status and Preliminary Data

Of the 350 well identifiers selected for analysis, the EPA received information on 334 wells. One of these was never drilled, ultimately providing the EPA with well files for 333 drilled wells.[36] Table 23 lists the number of wells for which valid data were provided by each operator and their designated company size.

Table 23. Number of wells for which data were provided by each operator. Company size, as determined for this analysis, is also listed. The nine operators provided data on a total of 333 oil and gas production wells.

Operator	Company Size	Number of Wells
Noble Energy	Large	67
ConocoPhillips	Large	57
Williams Production	Large	50
Clayton Williams Energy	Medium	36
SandRidge Energy	Medium	35
EQT Production	Large	29
MDS Energy	Small	24
Laramie Energy	Small	21
Hogback Exploration	Small	14
Total		333

Figure 12 shows a map of the 333 well locations. The well locations are distributed within 13 states: Arkansas, Colorado, Kentucky, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wyoming.

[36] Sixteen of the 350 well identification numbers were not valid for this project: 13 were duplicate entries, one was in Canada, one was not a well, and one was not actually owned by the selected operator. In total, roughly 5% of the 350 well identifiers chosen for review by the EPA do not correspond to oil and gas wells that have been hydraulically fractured. This provides a rough assessment of the accuracy of the original data received from the nine hydraulic fracturing service companies (the service company well list).

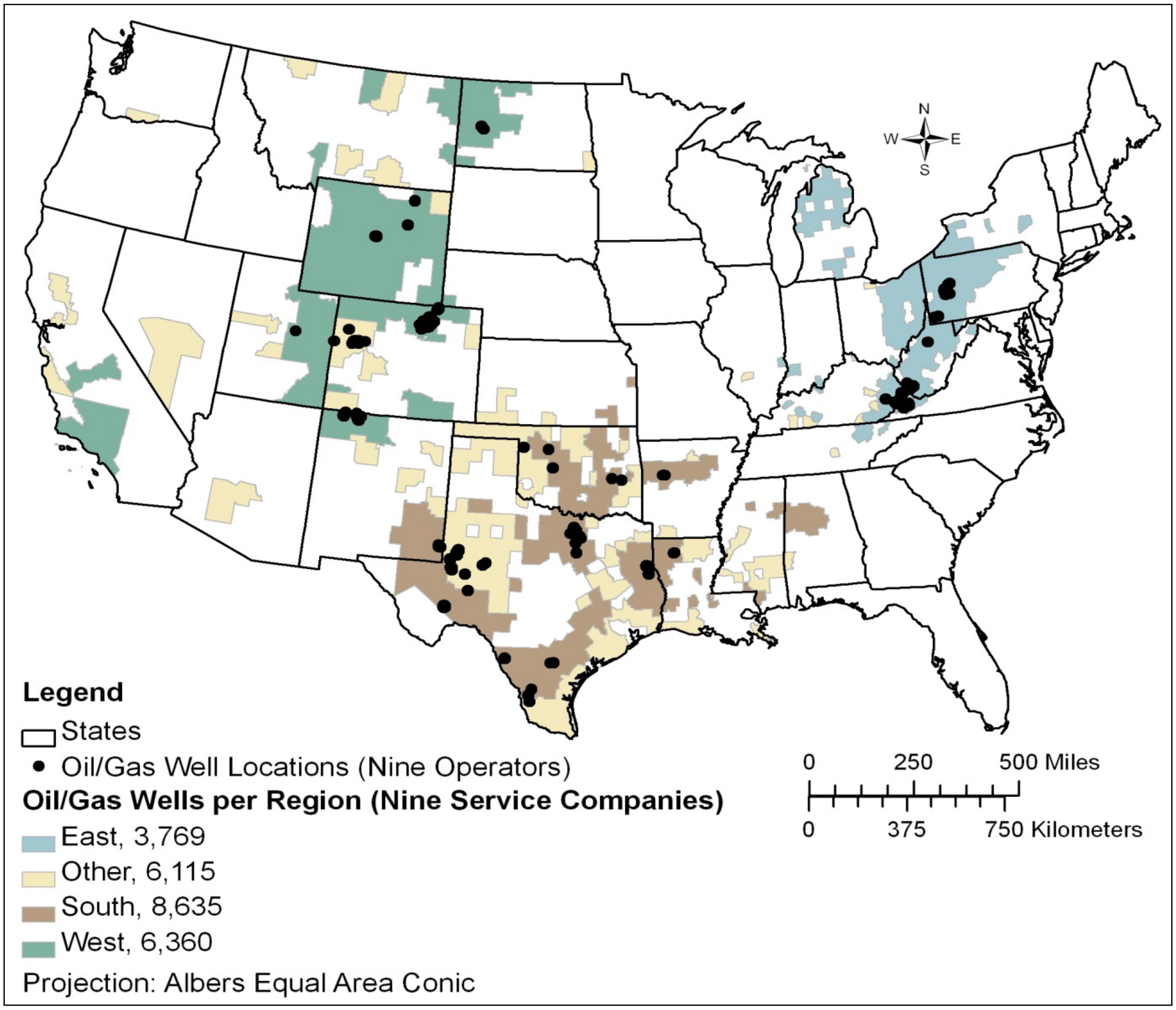

Figure 12. Locations of 333 wells (black points) selected for the well file review. Also shown are the locations of oil and gas production wells hydraulically fractured from September 2009 through October 2010. The information request to service companies (September 2010) resulted in county-scale locations for 24,925 wells. The service company wells are represented above as regional well summaries and summarize only 24,879 wells because the EPA did not have locational information for 46 of the 24,925 reported wells. (ESRI, 2010a, b; US EPA, 2011a, d)

The EPA received approximately 9,670 electronic files in response to the August 2011 information request. The amount of information received varied from one well file to another. Some well files included nearly all of the information requested, while others were missing information on entire topical areas. Some of the data received were claimed as CBI under TSCA. The EPA has contacted all nine of the oil and gas operators to clarify its understanding of the data, where necessary, and to discuss how to depict the well file data while still protecting confidential information. The analyses described in the previous section are being performed according to CBI procedures (US EPA, 2003b), and the results are considered CBI until determinations are made or until data masking has been done to prevent release of CBI information.

The EPA is extracting available data from the well files that can be used to answer research questions related to all stages of the hydraulic fracturing water cycle. As of September 2012, the

EPA had extracted, and continues to extract, the following available information from all of the well files:

- Open-hole log analysis of lithology, hydrocarbon shows, and water salinity
- Chemical analyses of various water samples
- Well construction data
- Cement reports
- Cased-hole logs, including identifying cement tops and bond quality

Other data to be extracted includes the following:

- Source of water used for hydraulic fracturing
- Well integrity pressure testing
- Fluid volumes injected during well stimulation and type and amount of additives and proppant used
- Pressures used during hydraulic fracturing
- Fracture growth data including that predicted and that observed
- Flowback and produced water data following hydraulic fracturing including volume, disposition, and duration

The EPA is creating queries on the extracted data that are expected to determine whether drinking water resources were protected from hydraulic fracturing operations. The results of these queries may indicate the frequency and variety of construction and fracturing techniques that could lead to impacts on drinking water resources. The results may provide, but may not be limited to, information on the following:

- Sources of water used for hydraulic fracturing
- Vertical distance between hydraulically fractured zones and the top of cement sheaths
- Quality of cementing near hydraulic fracturing zones, as determined by a cement bond index
- Number of well casing intervals left uncemented and whether there are aquifers in those intervals
- Distribution of depths of hydraulically fractured zones from the surface
- Frequency with which various tests are conducted, including casing shoe pressure tests and casing pressure tests
- Types of rock formations hydraulically fractured
- Types of well completions (e.g., vertical, horizontal)
- Types and amounts of proppants and chemicals used during hydraulic fracturing
- Amounts of fracture growth

- Distances between wells hydraulically fractured and geologic faults
- Proportions of fluid flowed back to the surface following hydraulic fracturing and the disposition of the flowback

3.4.5. Next Steps

Additional Database Analysis. The EPA plans to conduct further reviews of the well files to extract information relating to water acquisition for hydraulic fracturing, hydraulic fracturing fluid injection, and wastewater management.

Statistical Analysis. Once the data analysis has been completed, where possible, extrapolation of the results will be performed to the sampled universe of 24,925 wells, using methods consistent with published statistical practices (Kish, 1965).

Confidential Business Information. The EPA is working with the oil and gas operators to determine how best to summarize the results so that CBI is protected while upholding the agency's commitment to transparency.

3.4.6. Quality Assurance Summary

The EPA and its contractor, The Cadmus Group, Inc., are evaluating the well file contents. The QAPP associated with this project, "National Hydraulic Fracturing Study Evaluation of Existing Production Well File Contents (Version 1)," was approved on January 4, 2012 (US EPA, 2012j). A supplemental QAPP developed by Cadmus was approved on March 6, 2012 (Cadmus Group Inc., 2012b). Each team involved in the well file review underwent a separate TSA by the designated EPA QA Manager to ensure compliance with the approved QAPP. The audits occurred between April and August of 2012. No corrective actions were identified.

Westat, under contract with the EPA, is providing statistical support for the well file analysis. A QAPP, "Quality Assurance Project Plan v1.1 for Hydraulic Fracturing," was developed by Westat and approved on July 15, 2011 (Westat, 2011).

3.5. FracFocus Analysis

3.5.1. Relationship to the Study

Extracting data from FracFocus allows the EPA to gather publicly available, nationwide information on the water volumes and chemicals used in hydraulic fracturing operations, as reported by oil and gas operating companies. Data compiled from FracFocus are being used to help inform answers to the research questions listed in Table 24.

Table 24. Secondary research questions addressed by extracting data from FracFocus, a nationwide hydraulic fracturing chemical registry.

Water Cycle Stage	Applicable Research Questions
Water acquisition	How much water is used in hydraulic fracturing operations, and what are the sources of this water?
Chemical mixing	What are the identities and quantities of chemicals used in hydraulic fracturing fluids, and how might this composition vary at a given site and across the country?

3.5.2. Project Introduction

At the time the draft study plan was written in early 2011, the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission jointly launched a new national registry for chemicals used in hydraulic fracturing, called FracFocus (http://www.fracfocus.org; (GWPC, 2012b)). This registry, which has become widely accepted as the national hydraulic fracturing chemical registry, is an online repository where oil and gas well operators can upload information regarding the chemical compositions of hydraulic fracturing fluids used in specific oil and gas production wells. It has become one of the largest sources of data and information on chemicals used in hydraulic fracturing and may be the largest single source of publicly disclosed data for these chemicals. The registry also contains information on well locations, well depth, and water use. Confidential business information is not disclosed in FracFocus to protect proprietary or sensitive information.

FracFocus began as a voluntary program on January 1, 2011. Since its introduction, the amount of data in FracFocus has been steadily increasing. As of May 2012, the registry contained information on nearly 19,000 wells for which hydraulic fracturing fluid disclosures were entered (GWPC, 2012b). Seven states require operators to use FracFocus to report the chemicals used in hydraulic fracturing operations. In addition, many states are expected to pass or are working on legislation to require reporting with FracFocus.[37]

Although it represents neither a random sample nor a complete representation of the wells fractured during this time period, the number of well disclosures in FracFocus may constitute a large portion of the number of wells hydraulically fractured in the United States for this time period. For comparison, nine hydraulic fracturing service companies reported that nearly 25,000 wells were fractured between September 2009 and October 2010, as described in Section 3.3.

This analysis is gathering information on water and chemical use in hydraulic fracturing operations and attempts to answer the following questions:

- What are the patterns of water usage in hydraulic fracturing operations reported in FracFocus?
- What are the different sources of water reported in FracFocus, and is it possible to determine the relative proportions by volume or mass of these different sources of water?
- What are the identities of chemicals used in hydraulic fracturing fluids reported in FracFocus?
- Which chemicals are reported most often in FracFocus?
- What is the geographic distribution of the most frequently reported chemicals in FracFocus?

[37] The seven states requiring disclosure to FracFocus are Colorado, Louisiana, Montana, North Dakota, Oklahoma, Pennsylvania, and Texas. As of September 2012, the EPA is aware of eight more states considering the use of FracFocus: Alaska, California, Illinois, Kansas, Kentucky, New Mexico, Ohio, and West Virginia.

3.5.3. FracFocus Data

All data in FracFocus are entered by oil and gas companies that have agreed to "disclose the information in the public interest" (GWPC, 2012b). The Ground Water Protection Council, the organization that administers the registry, makes no specific claim about data quality in FracFocus. There is considerable variability in the posted data because they are uploaded by many different companies, including operator and service companies. Although FracFocus uses some built-in QA checks during the data upload process, several data quality issues are not addressed by these protocols. As a result, the EPA conducted a QA review of the data, as described in the next section.

Data in FracFocus are presented in individual PDF formats for individual wells; an example PDF is provided in Figure 13. Individual wells can be searched using a Google Maps application programming interface. In addition, well disclosure records can be searched by state, county, and operator. Results are returned by listing links to individual PDF files. Because only single well disclosure records are downloadable, systematic analysis of larger datasets is more challenging. Data must be extracted and transformed into more appropriate formats (e.g., a Microsoft Access database) for this type of analysis.

Data in FracFocus can be classified into two general types: well or "header" data and chemical- or ingredient-specific data. Header data describe information about each well, including the fracture date, API number, operator, well location, and total fluid volume, as shown in Figure 13. Chemical-specific data provide the trade names of ingredients, the chemicals found in these ingredients, and the concentrations used in the hydraulic fracturing fluid. Some well disclosures include information on the type or source of water in the chemical-specific data table.

The EPA has downloaded data in FracFocus on wells hydraulically fractured during 2011 and the beginning of 2012. It is beyond the scope of this project to evaluate the quality or representativeness on a national scale of the data submitted to FracFocus by oil and gas operators. The data cannot be assumed to be a complete or statistically representative of all hydraulically fractured wells. However, because FracFocus contains several thousands of well disclosures distributed throughout the United States, the EPA believes that the data in FracFocus are generally indicative of hydraulic fracturing activities during the time period covered. Therefore, it may be possible to find geographic patterns of occurrence or usage, including volume of water, frequency of chemical usage, and amounts of chemicals used, assuming that data in FracFocus meet quality requirements.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	12/12/2012
State:	Anystate
County:	Anycounty
API Number:	09-999-99999
Operator Name:	Any Oil and Gas
Well Name and Number:	Somewhere #1
Longitude:	-106.999
Latitude:	38.999
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	12,000
Total Fluid Volume (gal)*:	3,000,000

Mockup for discussion purposes only

Hydraulic Fracturing Fluid Composition:

Note: This mockup was designed to emulate the requirements of the Colorado regulations. For Texas the Maximum Ingredient Concentration in HF Fluid (% by Mass) would not be listed for Non-MSDS Ingredients.

Trade Name (Additive)	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Acid	Acme	Acid	Hydrochloric acid	7647-01-0	60.00%	0.08940%	
			Acetic acid	64-19-7	35.00 %	0.00160%	
			Citric acid	77-92-9	35.00%	0.00100%	
FEAC-20	Acme	Iron control	Methanol	67-56-1	100.00%	0.00080%	
LAI-20	Acme	Corrosion inhibitor	Propargyl alcahol	107-19-7	100.00%	0.00020%	
FR-8	Acme	Friction reducer	Petroleum distillate	Proprietary	100.00%	0.01950%	Acme***
LSI-21	Acme	Scale Inhibitor	Amonium chloride	12125-02-9	75.00%	0.00070%	
			Polyethylene glycol	25322-88-3	35.00%	0.02020%	
Bio-clear 5000	Extrachem	Biocide	2,2-dibromo-3-nitriopropionamide	10222-01-2	100.00%	0.00290%	
Ingredients shown above are subject to 29 CFR 1910.1200(i) and appear on Material Safety Data Sheets (MSDS). Ingredients shown below are Non-MSDS							
			Fresh water	00-55-0		54.27000%	
			Produced water	00-55-0		27.20000%	
			Sand	N/A		13.00000%	
			Hemicellulose enzyme concentrate	9025-56-3		1.50000%	
			Mineral oil	99-18-4		2.00000%	
			Gluteraldehyde	111-30-8		1.50000%	
			Guar gum	9000-70-8		1.00000%	

* Total Fluid Volume sources may include fresh water, produced water, and/or recycled water, or other fluids such as propane

** Information is based on the maximum potential for concentration and thus the total may be over 100%

*** Name of company or individual that requested proprietary status under a state or federal law

N/A means Not applicable

Proprietary means a chemical that is non disclosable under a state or federal law protecting confidential business information or trade secrets.

Ingredient information for chemicals subject to 29 CFR 1910.1200(i) and Appendix D are obtained from the supplier's Material Safety Data Sheets (MSDS).

Figure 13. Example of data disclosed through FracFocus. Data included in each PDF can be classified into two general types: well or "header" data and chemical- or ingredient-specific data. Header data are located in the top table, and ingredient-specific data are found in the bottom table. Provided by Ground Water Protection Council.

3.5.4. Research Approach

Data were first extracted from the FracFocus website, put into more appropriate formats for QA review, and then organized into a final database for analysis of fracturing fluid chemicals and water usage and source. The geographic coordinates provided for wells will be linked to both the chemical and water data (Figure 13) to determine if regional patterns exist. A QA review was performed following the data extraction and initial processing. The last stage of this project involves the quantitative analyses of the QA-reviewed data. These three stages are described in more detail below.

3.5.4.1. Data Extraction and Organization

Records for 12,306 wells hydraulically fractured from January 1, 2011, through February 27, 2012, were extracted from FracFocus PDF files and converted to XML using Adobe Acrobat Pro X software. Header- and chemical-specific data were mined from the XML files using text recognition software (Cadmus Group Inc., 2012b).[38] Using this technique, data representing 12,173 (>98% of the downloaded records) well records were compiled. Once fully processed, the data records were organized into two working files: one file containing header data that included well-specific geography, fracturing fluid volume, and well depth and one file containing chemical-specific data. The working files are linked by unique well identification numbers assigned by the contractor that developed the database for EPA.

3.5.4.2. Data Quality Assurance Review

Manual and automated methods were used to assess the data quality and make necessary adjustments. Records in the header data working file were flagged according to the following criteria: duplicate records, as identified by identical API numbers; fracture dates outside the January 1, 2011, to February 27, 2012, time period; anomalously large or small volumes of water; and anomalously deep or shallow true vertical depths. These records were kept in the working files, but flagged in order to exclude them from future analyses. Half of the duplicate records were excluded from all queries and analyses.

Spatial data from the well records include three sources, which can be used to perform quality checks: state and county names, latitude and longitude coordinates, and the state and county information encoded in the first five digits of the API Well Number (Figure 13). To validate the location of the wells, the state and county information from each of the locational fields was compared. State and county information (ESRI, 2010a, b) was assigned to the latitude and longitude coordinates by spatially joining the data in ArcGIS (ESRI, version 10). Validated spatial location was available for 12,163 wells (>99% of records extracted) (Cadmus Group Inc., 2012b).

Chemical names in the “Ingredients” field of chemical-specific data table were standardized according to the CASRN provided in the associated “Chemical Abstract Service Number” field

[38] The text recognition software is highly sensitive to inconsistencies in reporting. If an operator departs from the general template when creating the well record, the record will be passed over or data will be extracted incorrectly. The contractor was able to convert data from 12,173 of the 12,302 well records into a more useable format (Cadmus Group Inc., 2012b).

(Figure 13). As described in Chapter 6, the EPA has compiled and curated a list of chemicals reported to be used in hydraulic fracturing fluids from many data sources. This list was used to standardize the chemical names provided in FracFocus by matching CASRNs.[39]

Water sources were also identified from the "Ingredients" field. Data were first organized to identify wells where water has been listed as a trade name or ingredient and has been used as a "carrier" or "base" fluid, excluding records that indicated the water has been used as a solvent for hydraulic fracturing chemicals. Additionally, records listing the CASRN for water (7732-18-5) and an additive concentration of 70% to 100% were identified.

3.5.4.3. Data Analysis

Following the QA review, all data were organized into four data tables: locational data for each well disclosure, the original chemical-specific data for each well disclosure, the QA-reviewed chemical-specific data for each well disclosure, and records with water as ingredient. These four tables have been imported into a database and linked together using key fields, where they can be used for the analyses described below. The raw, pre-QA data values for well disclosures and chemical ingredients as they were exported from FracFocus have also been imported into the database for baseline reference data to prevent any loss of original operator data.

Water Acquisition. Total water volume data that meet the QA requirements are being used to analyze general water usage patterns on national, state, and county scales of interest. Additional queries may be run that analyze water usage by operator and by production type (oil or gas).

Data will be summarized by water source or type for records where this information is provided. Concentrations of water by source type are generally found in the "Maximum Ingredient Concentration in HF (hydraulic fracturing) Fluid" field (Figure 13), which is reported as a percentage by mass, not percentage by total water volume. In some situations, there will be enough information in FracFocus to calculate water volumes by type (V_{H2O}^{i}), whether fresh water (e.g., surface water) or non-fresh water (e.g. recycled/produced, saline, seawater or brine). Given the FracFocus-reported total water volume (V_{H2O}^{total}) (US gallons) and assuming that volumes are effectively additive, and where *n* is the number of water types,

$$V_{H2O}^{total} \cong \sum_{i=1}^{n} V_{H2O}^{i} \qquad (1)$$

using the FracFocus-reported maximum water concentration in the hydraulic fracturing fluid (percent by mass for each water type, x_{H2O}^{i}), and assuming an average density for each water type (ρ_{H2O}^{i}) (lb/US gallons), the volume of each water type is expressed as:

$$V_{H2O}^{i} = \frac{x_{H2O}^{i}}{\rho_{H2O}^{i}} m_{total} \qquad \text{(i = 1, n)} \qquad (2)$$

With *n* equations and *n* unknowns represented by equations (1) and (2), the unknown total mass of the hydraulic fracturing fluid (m_{total}) (lb) can be calculated:

[39] CASRNs not already found on the EPA's list of chemicals reported to be used in hydraulic fracturing fluids were added to the list following the process outlined in Chapter 6.

$$m_{total} = \frac{V_{H2O}^{total}}{\sum_{i=1}^{n} \frac{x_{H2O}^{i}}{\rho_{H2O}^{i}}} \quad (3)$$

and the volume of each water type (V_{H2O}^{i}) back-calculated using equation (2).[40]

This calculation can only be made in the situation where the density of the fluid is known or reported. For example, in the situation where a FracFocus ingredient is clearly labeled fresh (surface) water and carrier or base fluid, a water density may be assumed between 8.34 lb/US gallon at 32 °F and 8.24 lb/US gallon at 100 °F (Lide, 2008). In other situations, the density for the carrier or base fluid may be reported in the FracFocus comment field.

Chemical Usage. Queries of the FracFocus data will include the total number of unique chemical records nationally, by state, per production type (oil or gas), fracture date, and operator represented. Additionally, the data may be queried to identify the frequency or number of well disclosures in which each chemical is used nationally, by state, per production type, within a fracture date range, and by operator represented. Lists of the top 20 to 30 most frequently used chemicals in hydraulic fracturing are likely to be generated at the nation, region, or state level. Some of the most frequently occurring chemicals will be mapped to show distribution of occurrence. Since chemicals claimed as CBI or proprietary do not have to be reported in FracFocus, the number of chemicals disclosed is likely to be lower than the total number of chemicals used.

3.5.5. Status and Preliminary Data

The data have been extracted from FracFocus, reviewed for quality issues, and organized in a database for analysis. Draft queries have been developed for water usage and chemical frequency occurrence nationwide using the database. Preliminary analyses have been conducted as of November 2012. Table 25 summarizes, by state, the well data that were downloaded from FracFocus in early 2012.

Table 25. Number of wells, by state, with data in FracFocus as of February 2012. These data represent wells fractured and entered into FracFocus between January 1, 2011, and February 27, 2012.

State	Number of Wells	State	Number of Wells
Alabama	54	North Dakota	359
Alaska	24	Ohio	11
Arkansas	807	Oklahoma	414
California	79	Pennsylvania	1,050
Colorado	2,307	Texas	4,859
Kansas	22	Utah	409
Louisiana	621	Virginia	23
Mississippi	1	West Virginia	93
Montana	28	Wyoming	591
New Mexico	421	*Total*	*12,173*

[40] The EPA recognizes that volume is not a conserved quantity and estimates that the error introduced by assuming that volumes are additive is, in this case, negligible when compared to expected volume and density reporting errors.

During the QA review of the data, the EPA identified 422 pairs of potential duplicate well disclosure records (844 total records). A total of 277,029 chemicals were reported in all of the well disclosure records. This number includes chemicals listed multiple times (either for the same well or in many wells) and 12,464 instances where "water" was listed as an ingredient in the chemical-specific data table. The QA review of the chemicals identified 347 unique ingredients that match the EPA CASRN list of chemicals and approximately 60 CASRNs that were not previously known to be used in hydraulic fracturing fluids. One hundred eighty-four well records had ingredient lists that fully matched the EPA CASRN list. Chemical entries in FracFocus that contained "CBI," "proprietary," or "trade secret" as an ingredient were only 1.3% (3,534 of 277,029) of all chemical ingredients reported in FracFocus. Operators reported at least one chemical ingredient as "CBI," "proprietary," or "trade secret" in 1,924 well records.

Water was identified as a carrier or base fluid in 10,700 well records (88% of the 12,173 well records successfully extracted from FracFocus). Seven categories of source water were identified: fresh, surface, sea, produced, recycled, brine, and treated. Definitions for the categories are not provided by operators or FracFocus and some categories appear to overlap or may be synonymous. Only 1,484 well records identified a water source for those wells that used water as a carrier or base fluid.

3.5.6. Next Steps

The EPA will complete its analysis of the FracFocus data that have already been downloaded. In addition, the EPA plans to complete another data download in order to obtain a second year's worth of data. Once the second round of data has been extracted, the EPA will conduct a QA review and data analysis similar to the one described for the first round of downloaded data.

3.5.7. Quality Assurance Summary

The EPA and its contractor, The Cadmus Group, Inc., are extracting and analyzing data from FracFocus. The QAPP associated with this project, "Analysis of Data Extracted from FracFocus (Version 1)," was approved in early August 2012 (US EPA, 2012g). A TSA of the analysis was conducted by the designated EPA QA Manager shortly after on August 15, 2012; no corrective actions were identified. A supplemental QAPP developed by Cadmus was approved March 6, 2012 (Cadmus Group Inc., 2012b).

4. Scenario Evaluations

The objective of this approach is to use computer models to explore hypothetical scenarios across the hydraulic fracturing water cycle. The models include models of generic engineering and geological scenarios and, where sufficient data are available, models of site-specific or region-specific characteristics. This chapter includes progress reports for the following projects:

4.1. Subsurface Migration Modeling

Lawrence Berkeley National Laboratory (LBNL), in consultation with the EPA, will simulate the hypothetical subsurface migration of fluids (including gases) resulting from six possible mechanisms using computer models. The selected mechanisms address the research questions identified in Table 26.

Table 26. Secondary research questions addressed by simulating the subsurface migration of gases and fluids resulting from six possible mechanisms.

Water Cycle Stage	Applicable Research Questions
Well injection	• How effective are current well construction practices at containing gases and fluids before, during, and after fracturing? • Can subsurface migration of fluids or gases to drinking water resources occur and what local geologic or man-made features may allow this?

4.1.1. Project Introduction

Stakeholders have expressed concerns about hydraulic fracturing endangering subsurface drinking water resources by creating high permeability transport pathways that allow hydrocarbons and other fluids to escape from hydrocarbon-bearing formations (US EPA, 2010b, d, e, f, g). Experts continue to debate the extent to which subsurface pathways could cause significant adverse consequences for ground water resources (Davies, 2011; Engelder, 2012; Harrison, 1983, 1985; Jackson et al., 2011; Myers, 2012a, b; Osborn et al., 2011; Warner et al., 2012). The segment of the population that receives drinking water from private wells may be especially vulnerable to health impacts from impaired drinking water. Unlike water distributed by public water systems, water from private drinking water wells is not subject to National Primary Drinking Water Regulations, and water quality testing is at the discretion of the well owner.

Lawrence Berkeley National Laboratory, in coordination with the EPA, is using numerical simulations to investigate six possible mechanisms that could lead to upward migration of fluids, including gases, from a shale gas reservoir and the conditions under which such hypothetical scenarios may be possible. The possible mechanisms include:

- Scenario A (Figure 14): Defective or insufficient well construction coupled with excessive pressure during hydraulic fracturing operations results in damage to well integrity during the stimulation process. A migration pathway is then established through which fluids could travel through the cement or area near the wellbore into overlying aquifers. In this scenario, the overburden is not necessarily fractured.
- Scenario B1 (Figure 15): Fracturing of the overburden because inadequate design of the hydraulic fracturing operation results in fractures allowing fluid communication, either directly or indirectly, between shale gas reservoirs and aquifers above them. Indirect communication would occur if fractures intercept a permeable formation between the shale gas formation and the aquifer. Generally, the aquifer would be located at a more shallow depth than the permeable formation.
- Scenario B2 (Figure 16): Similar to Scenario B1, fracturing of the overburden allows indirect fluid communication between the shale gas reservoir and the aquifers after intercepting conventional hydrocarbon reservoirs, which may create a dual source of contamination for the aquifer.
- Scenario C (Figure 17): Sealed/dormant fractures and faults are activated by the hydraulic fracturing operation, creating pathways for upward migration of hydrocarbons and other contaminants.
- Scenario D1 (Figure 18): Fracturing of the overburden creates pathways for movement of hydrocarbons and other contaminants into offset wells (or their vicinity) in conventional reservoirs with deteriorating cement. The offset wells may intersect and communicate with aquifers, and inadequate or failing completions/cement can create pathways for contaminants to reach the ground water aquifer.
- Scenario D2 (Figure 19): Similar to Scenario D1, fracturing of the overburden results in movement of hydrocarbons and other contaminants into improperly closed offset wells (or their vicinity) with compromised casing in conventional reservoirs. The offset well could provide a low-resistance pathway connecting the shale gas reservoir with the ground water aquifer.

The research focuses on hypothetical causes of failure related to fluid pressure/flow and geomechanics (as related to operational and geological conditions and properties), and does not extend to investigations of strength of casing and tubing materials (an area that falls within the confines of mechanical engineering). Damage to the well casing due to corrosive reservoir fluids was one other scenario originally considered. Corrosion modeling requires a detailed chemical engineering analysis that is beyond the scope of this project, which focuses on geophysical and mechanical scenarios, so it is not a scenario pursued for this project. Additionally, hypothetical scenarios that would cause failure of well structural integrity (e.g., joint splits) are an issue beyond the scope of this study, as they involve material quality and integrity, issues not unique to hydraulic fracturing.

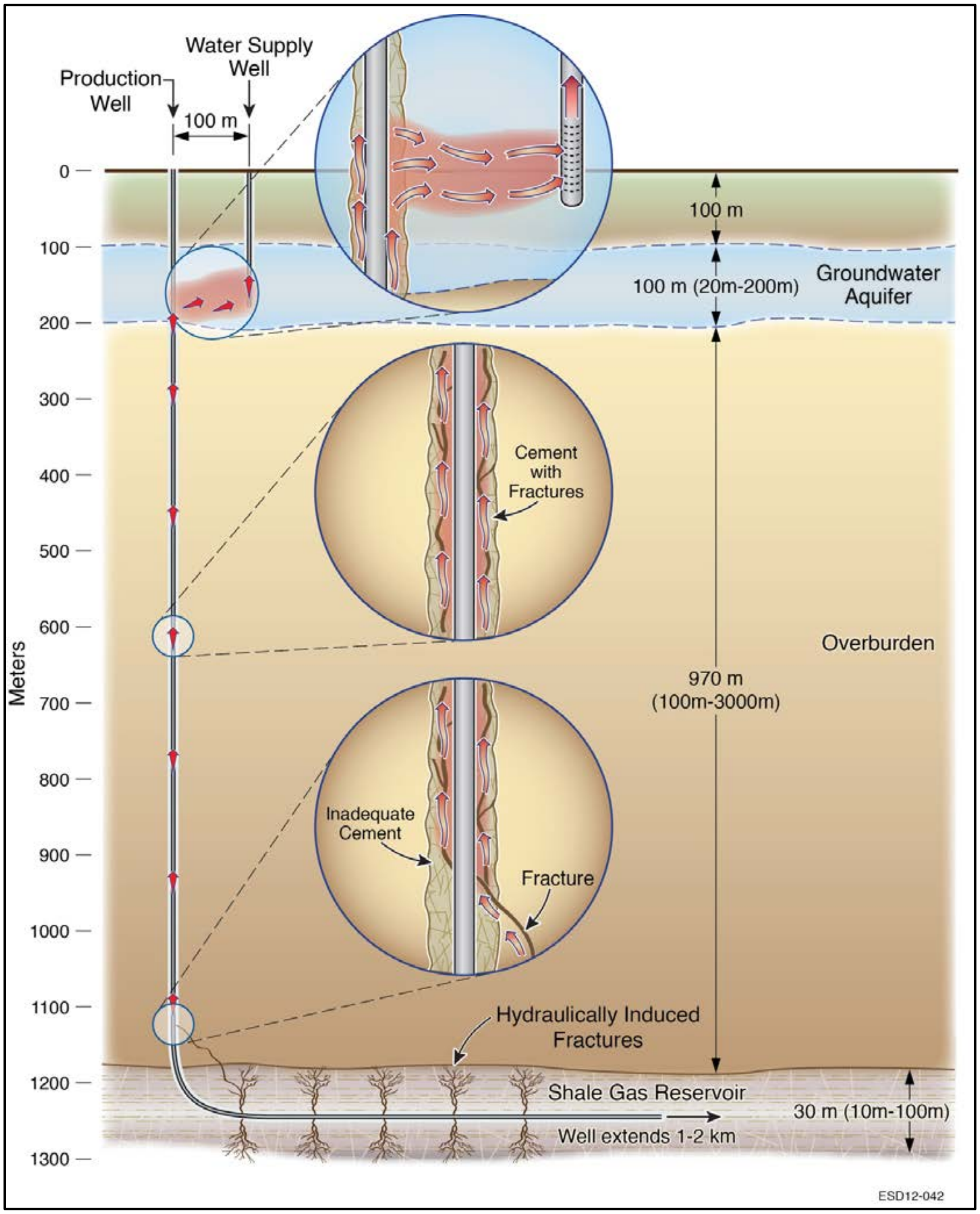

Figure 14. Scenario A of the subsurface migration modeling project. This scenario simulates a hypothetical migration pathway that occurs when a defective or insufficiently constructed well is damaged during excessive pressure from hydraulic fracturing operations. A migration pathway is established through which fluids could travel through the cement or area near the wellbore into overlying ground water aquifers.

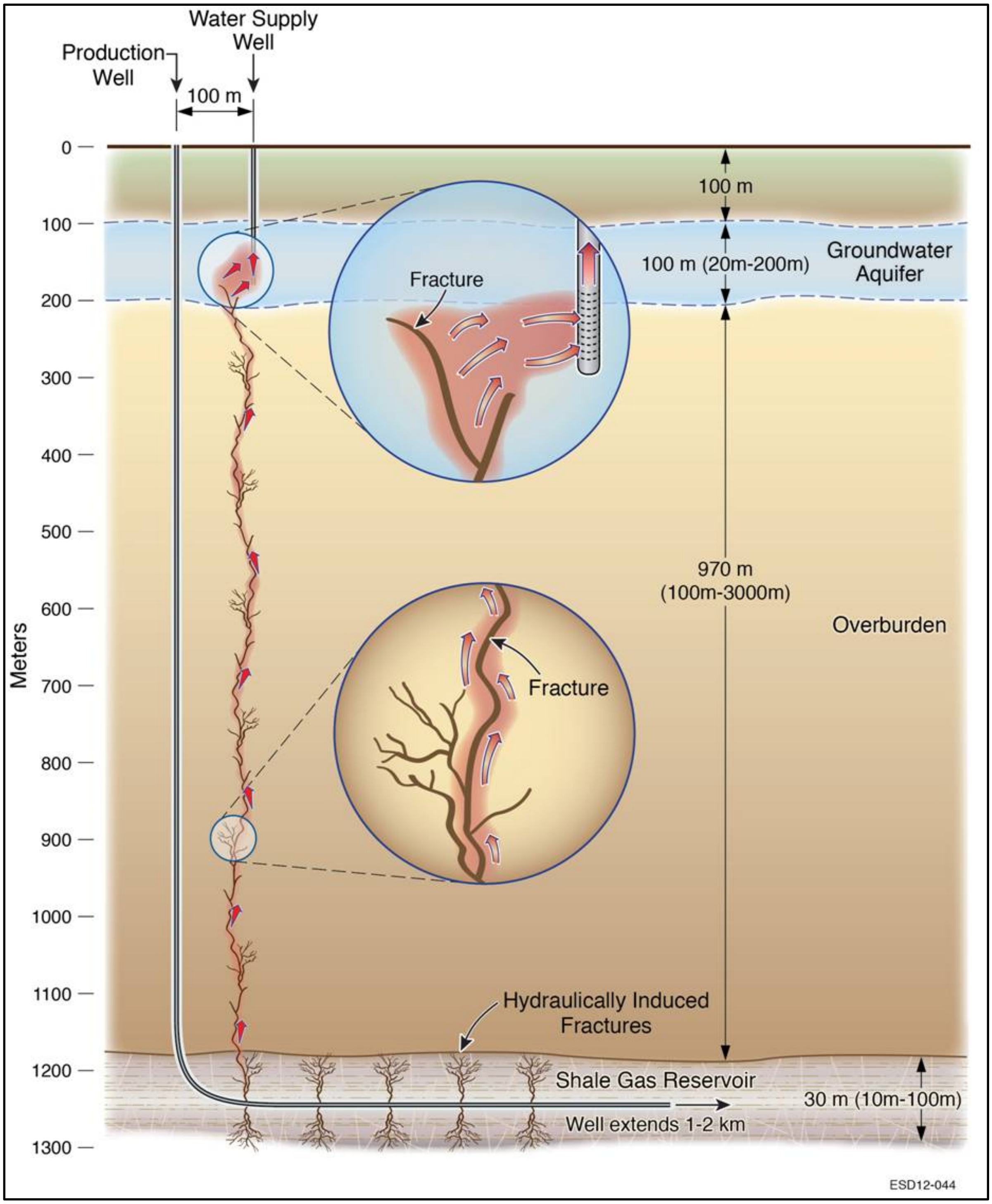

Figure 15. Scenario B1 of the subsurface migration modeling project. This hypothetical scenario simulates fluid communication, either directly or indirectly, between shale gas reservoirs and ground water aquifers as a result of the hydraulic fracturing design creating fractures in the overburden.

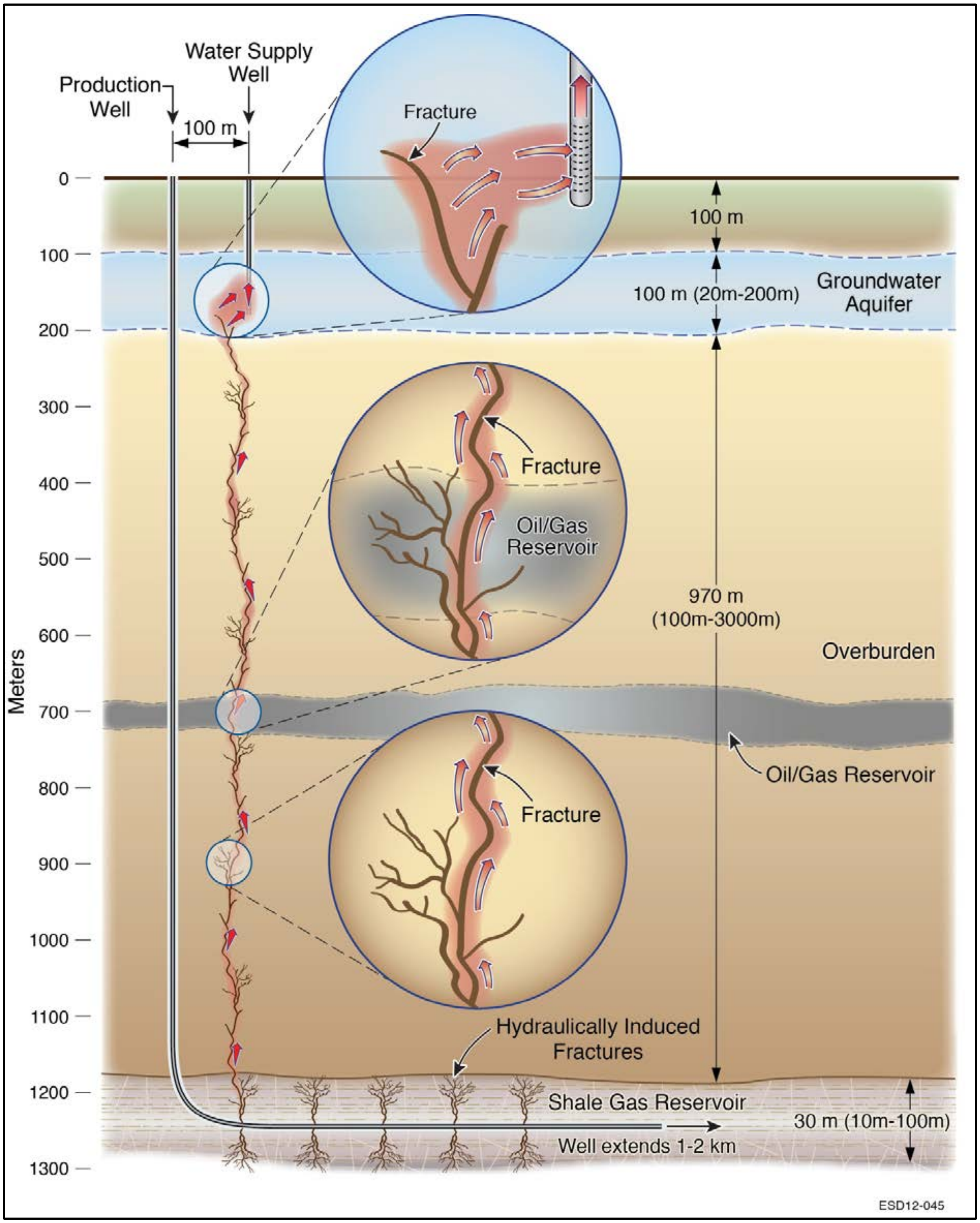

Figure 16. Scenario B2 of the subsurface migration modeling project. Similar to B1, this hypothetical scenario simulates fluid communication, either directly or indirectly, between shale gas reservoirs and ground water aquifers as a result of the hydraulic fracturing design creating fractures in the overburden. The fractures intercept a conventional oil/gas reservoir before communicating with the ground water aquifer, which may create a dual source of contamination in the aquifer.

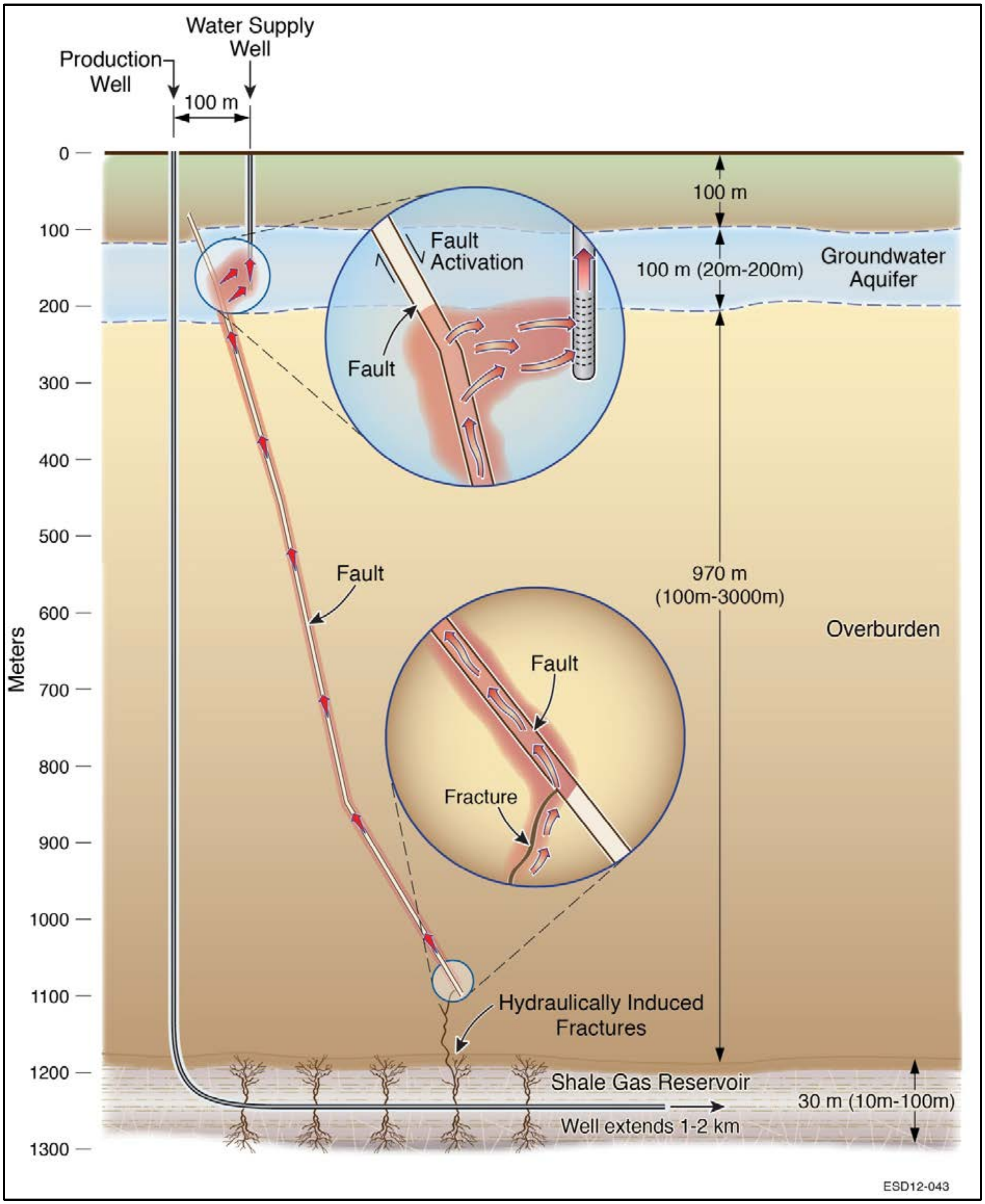

Figure 17. Scenario C of the subsurface migration modeling project. This hypothetical scenario simulates upward migration of hydrocarbons and other contaminants through sealed/dormant fractures and faults activated by the hydraulic fracturing operation.

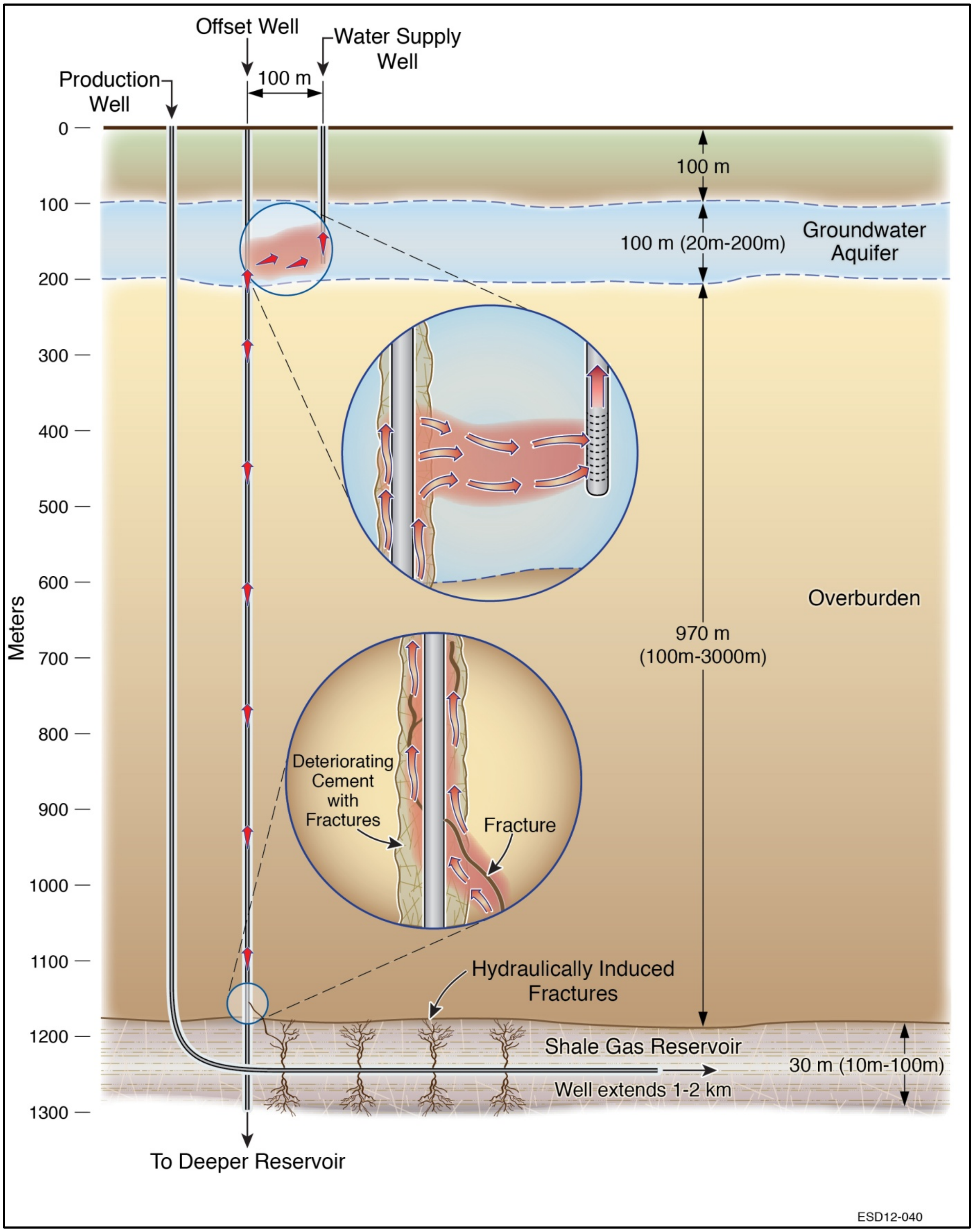

Figure 18. Scenario D1 of the subsurface migration modeling project. This hypothetical scenario simulates movement of hydrocarbons and other contaminants into offset wells in conventional oil/gas reservoirs with deteriorating cement due to fracturing of the overburden. The offset wells may intersect and communicate with aquifers, and inadequate or failing completions/cement can create pathways for contaminants to reach ground water aquifers.

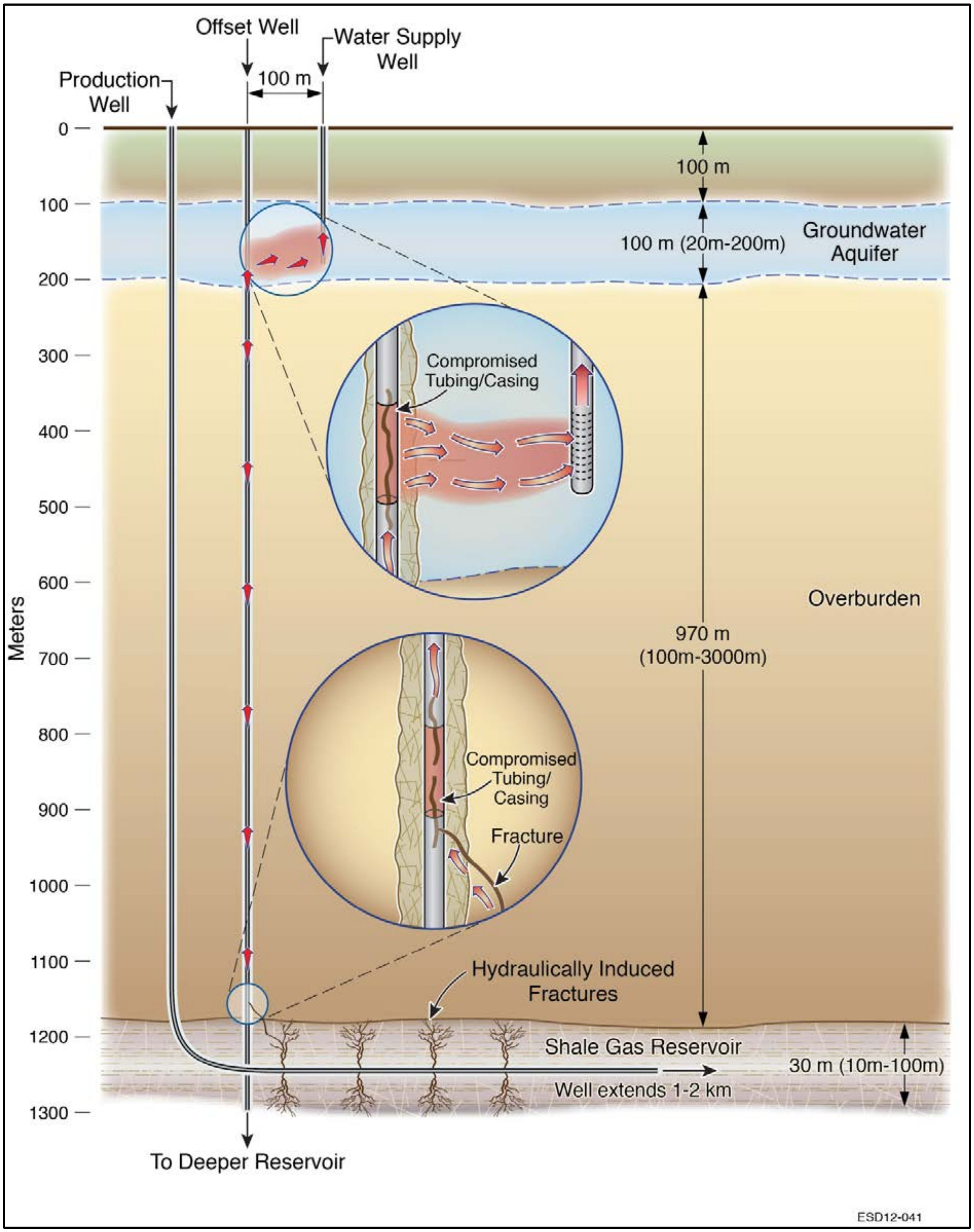

Figure 19. Scenario D2 of the subsurface migration modeling project. Similar to Scenario D1, this hypothetical scenario simulates movement of hydrocarbons and other contaminants into offset wells in conventional oil/gas reservoirs due to fracturing of the overburden. The offset wells in Scenario D2 are improperly closed with compromised casing, which provides a low-resistance pathway connecting the shale gas reservoir with the ground water aquifer.

4.1.2. Research Approach

Objectives of the subsurface migration scenario evaluation research project include:

- Determining whether the hypothetical migration mechanisms shown in Figures 14 through 19 are physically and geomechanically possible during field operations of hydraulic fracturing and, if so, identifying the range of conditions under which fluid migration is possible.
- Exploring how contaminant type, fluid pressure, and local geologic properties control hypothetical migration mechanisms and affect the possible emergence of contaminants in an aquifer.
- Conducting a thorough analysis of sensitivity to the various factors affecting contaminant transport.
- Assessing the potential impacts on drinking water resources in cases of fluid migration.

This research project does not assess the likelihood of a hypothetical scenario occurring during actual field operations.

Computational Codes. The LBNL selected computational codes able to simulate the flow and transport of gas, water, and dissolved contaminants concurrently in fractures and porous rock matrices. The numerical models used in this research project couple flow, transport, thermodynamics, and geomechanics to produce simulations to promote understanding of conditions in which fluid migration occurs.

Simulations of contaminant flow and migration began in December 2011 and identified a number of important issues that significantly affected the project approach. More specifically, the numerical simulator needed to include the following processes in order to accurately describe the hypothetical scenario conditions:

- Darcy and non-Darcy (Forchheimer or Barree and Conway) flow through the matrix and fractures of fractured media
- Inertial and turbulent effects (Klinkenberg effects)
- Real gas behavior
- Multi-phase flow (gas, aqueous, and potentially an organic phase of immiscible substances involved in the hydraulic fracturing process)
- Density-driven flow
- Mechanical dispersion, in addition to advection and molecular diffusion
- Sorption (primary and secondary) of ions introduced in hydraulic fracturing-related processes and gases onto the grains of the porous media, involving one of three possible sorption models (linear, Langmuir, or Freundlich) under equilibrium or kinetic conditions

Thermal differentials between ground water and shale gas reservoirs are substantial and may significantly impact contaminant transport processes. Thus, the simulator needed to be able to account for the following processes in order to fully describe the physics of the problem:

- Coupled flow and thermal effects, which affect fluid viscosity, density, and buoyancy and, consequently, the rate of migration.
- Effect of temperature on solubility. Lower temperatures can lead to supersaturation of dissolved gases or dissolved solids. The latter can result in halite formation stemming from salt precipitation, caused by lower temperatures and pressures as naturally occurring brines ascend toward the ground water. Halite precipitation can have a pronounced effect on both the specific fractures and the overall matrix permeability.

There is currently no single numerical model that includes all of these processes. Thus, the LBNL chose the Transport of Unsaturated Groundwater and Heat (TOUGH) family of codes[41] (Moridis et al., 2008) in combination with the existing modules listed in Table 27 to create a model that better simulates the subsurface flow and geomechanical conditions encountered in the migration scenarios.

Table 27. Modules combined with the Transport of Unsaturated Groundwater and Heat (TOUGH) (Moridis et al., 2008) family of codes to create simulations of subsurface flow and geomechanical conditions encountered in the migration scenarios designed by Lawrence Berkeley National Laboratory.

Module	Purpose
TOUGH+Rgas*	Describes the coupled flow of a real gas mixture and heat in geologic media
TOUGH+RgasH2O*	Describes the non-isothermal two-phase flow of a real gas mixture and water and the transport of heat in a gas reservoir, including tight/shale gas reservoirs
TOUGH+RGasH2OCont†	Describes physics and chemistry of flow and transport of heat, water, gases, and dissolved contaminants in porous/fractured media
ROCMECH§	Simulates geomechanical behavior of multiple porosity/permeability continuum systems and can accurately simulate the evolution and propagation of fractures in a formation following hydraulic fracturing

* (Moridis and Freeman, 2012)
† (Moridis and Webb, 2012)
§ (Kim and Moridis, 2012a, b, c, d, e)

The TOUGH+ code includes equation-of-state modules that describe the non-isothermal flow of real gas mixtures, water, and solutes through fractured porous media and accounts for all processes involved in flow through tight and shale gas reservoirs (i.e., gas-specific Knudsen diffusion, gas and solute sorption onto the media, non-Darcy flow, salt precipitation as temperature and pressure drop in the ascending reservoir, etc.) (Freeman, 2010; Freeman et al., 2011; Freeman et al., 2009a, b; Freeman et al., 2012; Moridis et al., 2010; Olorode, 2011). The LBNL paired relevant modules with TOUGH+ code: one code, TOUGH+RGasH2OCont (Moridis and Freeman, 2012), addresses the

[41] The TOUGH codes include TOUGH2, T2VOC, TMVOC, TOUGH2-MP, TOUGHREACT, TOUGH+, AND iTOUGH2. More information on the codes can be found at http://esd.lbl.gov/research/projects/tough.

physics and chemistry of flow and transport of heat, water, gases, and dissolved contaminants in porous/fractured media; a second code, TOUGH+RgasH2O (Moridis and Webb, 2012), describes the coupled flow of a gas mixture and water and the transport of heat; a third code, TOUGH+Rgas (Moridis and Webb, 2012), is limited to the coupled flow of a real gas mixture and heat in geologic media.

A geomechanical model, ROCMECH, was also coupled with the TOUGH+ code and modules (Table 27) and describes the interdependence of flow and geomechanics including fracture growth and propagation (Kim and Moridis, 2012a, b, c, d, e). The ROCMECH[42] code is designed for the rigorous analysis of either pure geomechanical problems or, when fully coupled with the TOUGH+ multi-phase, multi-component, non-isothermal code, for the simulation of the coupled flow and geomechanical system behavior in porous and fractured media, including activation of faults and fractures. The coupled TOUGH+ ROCMECH codes allow the investigation of fracture growth during fluid injection of water (after their initial development during hydraulic fracturing) using fully dynamically coupled flow and geomechanics and were used in a series of fracture propagation studies (Kim and Moridis, 2012a, b, c, d, e). The ROCMECH code developed by the LBNL for this study includes capabilities to describe both tensile and shear failure based on the Mohr-Coulomb model, multiple porosity concepts, non-isothermal behavior, and transverse leak-off (Kim and Moridis, 2012a).

Input Data. Input data supporting the simulations are being estimated using information from the technical literature, data supplied by the EPA, and expert judgment. Input data include:

- Site stratigraphy
- Rock properties (grain density, intrinsic matrix permeability, permeability of natural fracture network, matrix and fracture porosity, fracture spacing and aperture)
- Initial formation conditions (fracture and matrix saturation, pressures)
- Gas composition
- Pore water composition
- Gas adsorption isotherm
- Thermal conductivity and specific heat of rocks
- Parameters for relative permeability
- Hydraulic fracturing pressure
- Number of hydraulic fracturing stages
- Injected volumes

[42] ROCMECH is based on an earlier simulator called ROCMAS (Noorishad and Tsang, 1997; Rutqvist et al., 2001). The ROCMECH simulator employs the finite element method, includes several plastic models such as the Mohr-Coulomb and Drucker-Prager models, and can simulate the geomechanical behavior of multiple porosity/permeability continuum systems. Furthermore, ROCMECH can accurately simulate the process of hydraulic fracturing, i.e., the evolution and propagation of fractures in the formation following stimulation operations.

- Pressure evolution during injection
- Volumes of fracturing fluid recovered

Uncertainty in the data will be addressed by first analyzing base cases that involve reasonable estimates of the various parameters and conditions and then conducting sensitivity analyses that cover (and extend beyond) the possible range of expected values of all relevant parameters.

4.1.3. Status and Preliminary Data

The subsurface migration modeling project is proceeding along two main tracks. The first addresses the geomechanical reality of the mechanisms and seeks to determine whether it is physically possible (as determined and constrained by the laws of physics and the operational quantities and limitations involved in hydraulic fracturing operations) for the six migration mechanisms (Scenarios A to D2) to occur. The second axis focuses on contaminant transport, assuming that a subsurface migration has occurred as described in the six scenarios, and attempts to determine a timeframe for contaminants (liquid or gas phase) escaping from a shale gas reservoir to reach the ground water aquifer.

Analysis of Consequences of Geomechanical Wellbore Failure (Scenario A). A large database of relevant publications has been assembled, and several important well design parameters and hydraulic fracturing operational conditions have been identified as a foundation for the simulation. Two pathways for migration have been considered using TOUGH+RGasH2OCont: cement separation from the outer casing or a fracture pattern affecting the entire cement, from the producing formation to the point where the well intercepts the ground water formation.

A separate geomechanical study using TOUGH+RealGasH2O and ROCMECH will also assess the feasibility of either a fracture developing in weak cement around a wellbore or a cement-wellbore separation during the hydraulic fracturing process. The numerical simulation of the fracture propagation considered fracture development in the cement near the “heel” of a horizontal well during stimulation immediately after creation of the first fracture using varied geomechanical properties of gas-bearing shales. The work also involves sensitivity analyses of factors that are known to be important, as well as those that appear to have secondary effects (for completeness). Recent activities have focused mainly on such sensitivity analyses.

Analysis of the Consequences of Induced Fractures Reaching Ground Water Resources and after Intercepting Conventional Reservoirs (Scenarios B1 and B2). A high-definition geomechanical study, involving a complex fracture propagation model that incorporates realistic data and parameters (as gleaned from the literature and discussions with industry practitioners) was completed. A sensitivity analysis of the fracture propagation to the most important geomechanical properties and conditions is partially completed and will be included in the final publication.

Simulations of gas and contaminant migration from the shale gas reservoir through fractures into ground water are also in progress. The simulation domain is subdivided up to 300,000 elements[43] and up to 1.2 million equations, which requires very long execution times that can range from several days to weeks. Work continues to streamline the processing of the simulation to significantly reduce the execution time requirements.

Scoping calculations are in development to provide time estimates for the migration of gas and dissolved contaminants from the shale gas reservoir to the drinking water resource through a connecting fracture. As illustrated in Figure 15, the simulated system is composed of a 100-meter-thick aquifer (from 100 to 200 meters below the surface), a fracture extending from the bottom of the gas reservoir at 1,200 meters below surface to the base of the aquifer, which is 1,000 meters above the gas reservoir. These scoping studies indicated that the most important parameters and conditions were the permeability of the gas reservoir (matrix), the fracture permeability, the distance between the aquifer and the shale reservoir, and the pressure regimes in the aquifer and the shale. Results from this work are being analyzed and will be published when complete.

Analysis of Consequences of Activation of Native Faults and Fractures (Scenario C). The simulation conditions for the analysis of contaminant transport through native fractures and faults in response to the stimulation process have been determined, and the variations used to conduct a sensitivity analysis are being developed.

A geomechanical study using the TOUGH-FLAC[44] simulator began in March 2012 to investigate the possibility that hydraulic fracturing injections may create a pathway for transport through fault reactivation. The simulation input represents the conditions in the Marcellus Shale. Scoping calculations were developed to study the potential for injection-induced fault reactivation associated with shale gas hydraulic fracturing operations. From these scoping calculations, the LBNL simulation results suggest that the hydraulic fracturing stimulation, under conditions reported in published literature, does not appear to activate fault rupture lengths greater than 40 to 50 meters and could only give rise to microseismicity (magnitude <1), which is consistent with what has been observed in the field (NAS, 2012). Therefore, preliminary simulations suggest that the possibility of fault reactivation creating a pathway to shallow ground water resources is remote. A more detailed analysis to better resolve local conditions and mechanical response at the injection point is underway and a manuscript is in development (Rutqvist et al., 2012).

Analysis of the Consequences of Induced Fractures Intercepting Offset Unplugged Wells (Scenarios D1 and D2). A geomechanical study is in progress to assess the feasibility of a fracture extending

[43] Elements represent the spatial properties for the geology and the wells. Conceptually, the continuous real world is represented with discrete (numerical) elements, where each element has constant properties represented. With a large number of elements, a complex geologic and engineering conceptualization may be represented.

[44] TOUGH-FLAC links the public TOUGH model with the commercial and proprietary FLAC model, which is used extensively in geotechnical applications and covers a very wide spectrum of geomechanical processes (including fault representation, plasticity and/or elasticity, anisotropy, etc.) and can describe the interdependence of flow and geomechanical properties as the pressure/stress regime changes (Cappa and Rutqvist, 2011a, b, 2012; Cappa et al., 2009; Mazzoldi et al., 2012; Rutqvist, 2012; Rutqvist et al., 2007; Rutqvist et al., 2012) .

through the shale gas reservoir into the weak/fractured cement around, or the unplugged wellbore of offset wells (Figures 18 and 19). The LBNL is investigating two mechanisms for fluid communication. In the first case, the fractures extend across the shale stratum into a nearby depleted conventional reservoir with abandoned defective wells in the overburden or underburden. The energy for the lift of contaminants in this case is most likely provided by the higher pressure of the fluids in the shale (as the abandoned reservoir pressure is expected to be low) and by buoyancy; the main contaminant reaching the ground water is expected to be gas. In the second case, fractures extend from a deeper over-pressurized saline aquifer through the entire thickness of the shale to an overburden (a depleted conventional petroleum reservoir with abandoned unsealed wells). The energy for the lift of contaminants in this case is most likely provided by the higher pressure of the fluids in the shale and in the saline aquifer in addition to buoyancy, and the contaminants reaching the ground water are expected to include gas and solutes encountered in the saline aquifer.

4.1.4. Quality Assurance Summary

The QAPP, "Analysis of Environmental Hazards Related to Hydrofracturing (Revision: 0)," was accepted by the EPA on December 7, 2011 (LBNL, 2011).

A TSA of the work being performed by the LBNL was conducted on February 29, 2012. The designated EPA QA Manager found the methods in use satisfactory and further recommendations for improving the QA process were unnecessary. Work performed and scheduled to be performed was within the scope of the project. Work is proceeding on Scenarios A through D2 as described in Section 4.1.3. Reports, when presented, will be subjected to appropriate QA review.

4.2. Surface Water Modeling

4.2.1. Relationship to the Study

The EPA is using established surface water transport theory and models to identify concentrations of selected hydraulic fracturing-relevant chemicals at public water supply intakes located downstream from wastewater treatment facilities that discharge treated hydraulic fracturing wastewater to rivers. This work is expected to provide data that will be used to answer the research question identified in Table 28.

Table 28. Secondary research question addressed by modeling surface water discharges from wastewater treatment facilities accepting hydraulic fracturing wastewater.

Water Cycle Stage	Applicable Research Questions
Wastewater treatment and waste disposal	What are the potential impacts from surface water disposal of treated hydraulic fracturing wastewater on drinking water treatment facilities?

4.2.2. Project Introduction

When an operator reduces the injection pressure applied to a well, the direction of fluid flow reverses, leading to the recovery of flowback and produced water, collectively referred to as "hydraulic fracturing wastewater."[45] The wastewater is generally stored onsite before being transported for treatment, recycling or disposal. Most hydraulic fracturing wastewater is disposed in UIC wells. In Pennsylvania, however, wastewater has been treated in wastewater treatment facilities (WWTFs), which subsequently discharge treated wastewater to surface water bodies.

The extent to which common treatment technologies used in WWTFs effectively remove chemicals found in hydraulic fracturing wastewater is currently unclear.[46] Depending in part on the concentration of chemicals in the effluent, drinking water quality and the treatment processes at public water systems (PWSs) downstream from WWTFs might be negatively affected. For example, bromide in source waters can cause elevated concentrations of brominated disinfection byproducts (DBPs) in treated drinking water (Brown et al., 2011; Plewa et al., 2008),[47] which are regulated by the National Primary Drinking Water Regulations.[48] To learn more about impacts to downstream PWSs, the Pennsylvania Department of the Environment asked 25 WWTFs that accept Marcellus wastewater to monitor effluent for parameters such as radionuclides, total dissolved solids (TDS), alkalinity, chloride, sulfate, bromide, gross alpha, radium-226 and -228, and uranium in March 2011 (PADEP, 2011). The department also asked 14 PWSs with surface water intakes downstream from WWTFs that accept Marcellus wastewater to test for radionuclides, TDS, pH, alkalinity, chloride, sulfate, and bromide (PADEP, 2011). Bromide and radionuclides are of particular concern in discharges because of their carcinogenicity and reproductive and developmental affects.

The EPA will use computer models—mass balance, empirical, and numerical—to estimate generic impacts of bromide and radium in wastewater discharges, based on the presence of these chemicals in discharge data from WWTFs in Pennsylvania, impacts to downstream PWSs' ability to meet National Primary Drinking Water Regulations for DBPs and radionuclides, and the potential human health impacts from the chemicals.[49] Uranium, also a radionuclide, was frequently not detected by analytical methods for the discharges and therefore not considered for simulations. The generic model results are designed to illustrate the general conditions under which discharges might cause impacts on downstream public water supplies. The analysis will include the effect of distance to the PWS, discharge concentration, and flow rate in the stream or river, among others. The uncertainties in these quantities will be addressed through Monte Carlo analysis, as described below.

A steady-state mass balance model provides an upper-bound impact assessment of the transport simulation and a partially transient approach simulates the temporal variation of effluent concentration and discharge. Key data collected to model the transport of potential contaminants include actual effluent data from WWTF discharges and receiving water body flow rates. Effluent data can be obtained from National Pollutant Discharge Elimination System (NPDES) monitoring

[45] Produced water is produced from many oil and gas wells and not unique to hydraulic fracturing.

[46] See Section 5.2 for a more thorough discussion and for EPA-funded research into this question.

[47] See Section 5.3 for more information on DBPs and related research.

[48] Authorized by the Safe Drinking Water Act.

[49] Discharge data for four WWTFs in Pennsylvania that accepted oil and gas wastewater during 2011 are available on the EPA's website at http://www.epa.gov/region3/marcellus_shale/.

data reported to states by the dischargers.[50] NPDES information also documents the design of the industrial treatment plants, which can give insights into the capabilities of these and similarly designed treatment plants. The US Geological Survey (USGS) provides limited water quality and flow rate data from monitoring stations within the watersheds of the receiving water bodies. The surface water modeling results will directly address the applicable secondary research question (Table 28) by evaluating the possible impacts from a permitted release of treated effluent on both a downstream drinking water intake and in a watershed where there may be multiple sources and receptors.[51]

4.2.3. Research Approach

Multiple approaches generate results on impacts: steady-state mass balance; transient empirical modeling; and a transient, hybrid empirical-numerical model developed by the EPA. The results of the mass balance model simulate possible impacts during a large volume, high concentration discharge without natural attenuation of contaminants. The empirical model and a hybrid empirical-numerical model estimate impacts in a more realistic setting with variable chemical concentrations, discharge volumes, and flow rates of the receiving surface water. The numerical model confirms the results of the empirical and hybrid models. The numerical modeling is based on an approach developed for this study from existing methods (Hairer et al., 1991; Leonard, 2002; Schiesser, 1991; Wallis, 2007). Application of these three types of models provides a panoramic view of possible impacts and enhances confidence in the study results.

Mass Balance Approach Estimates Impacts from an Upper-Bound Discharge Scenario. A simple, steady-state mass balance model simulates drinking water impacts from upper-bound discharge cases. This model assumes that the total mass of the chemical of interest is conserved during surface water transport and that the chemical concentration does not decrease due to reaction, decay, or uptake. The model estimates potential impacts to downstream PWSs using the maximum effluent concentration, maximum WWTF discharge volume, minimum flow rate in the receiving stream, and the distance to the downstream PWS intake. The EPA constructed generic discharge scenarios for rivers with varying flow regimes to determine the potential for adverse impacts at drinking water intakes. Because the parameters describing transport are uncertain, Monte Carlo techniques will be used to generate probabilistic outputs of the model.

Empirical Model Estimates Impacts with Varying Discharge Volumes over Time. The upper-bound case simulated in the steady-state mass balance model may be too conservative (by providing larger concentration estimates) to accurately represent downstream concentrations of chemicals since effluent concentrations, treatment plant discharge volumes, and flow rates change over time. Therefore, the EPA will also use an empirical transport model originally developed by the USGS (Jobson, 1996) to simulate impacts from varying monthly discharge volumes over time. The

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[50] Information on WWTF discharges in Pennsylvania can be found at https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx.

[51] Impacted watersheds may also have other sources of compounds of interest, possibly acid mine drainage and coal-fired utility boilers. This is discussed in more detail in Section 5.1, which also outlines work being done by the EPA to assess the contribution of hydraulic fracturing wastewater to contamination in surface water bodies.

empirical approach is based on tracer studies performed around the United States since the early 1970s (e.g., Nordin and Sabol (1974)). The empirical equations address two major difficulties in applying models to chemical transport scenarios: the inability to estimate travel times from cross-sectional data and the reduction of concentration due to turbulent diffusion. The empirical equation approach gives an estimate of travel time and peak concentration so that the model does not need to be calibrated to tracer data.

Hybrid Empirical-Numerical Model Estimates Impacts for River Networks. The original empirical approach was suited for a single river segment, or reach, of spatially uniform properties. The hybrid empirical-numerical model being developed by the EPA to expand the capabilities of the just-described Jobson technique will easily account for multiple reaches that can form branching river networks. Similar to all statistical relationships, the empirical equations do not always match tracer data exactly; therefore, the EPA is including the ability to perform Monte Carlo techniques in the software being developed. The EPA will confirm the accuracy of the hybrid model with tracer data that fall within the range of Jobson's original set of inputs (taken from Nordin and Sabol (1974)) as well as later data from the Yellowstone River that provide a real-world test of this approach (McCarthy, 2009).

The numerical portion of the hybrid model provides a direct and automatic comparison with the empirical equations. The method is based on a finite difference solution to the transport equation using recent developments in modeling to improve accuracy (Hairer et al., 1991; Leonard, 2002; Schiesser, 1991; Wallis, 2007). By including this numerical method, a hybrid empirical-numerical approach can be achieved. The empirical travel times from Jobson (1996) can be used to parameterize velocity in the numerical method. Dispersion coefficients can be derived from empirical data or a method developed by Deng et al. (2002). Using these approaches provides improved accuracy in the simulation results. The EPA will prepare a user's guide to the model and make both the computer model and user's guide widely available for duplicating the results prepared for this project and for more general use.

For the generic simulations described above, effluent concentrations and discharge volumes will be modeled directly as variable inputs based on the effluent data evaluation (as discussed next in Section 4.2.4), while flow conditions will be modeled as low, medium, and high flow. Because the parameters describing transport are uncertain, statistical measures and Monte Carlo techniques will be used to generate probabilistic outputs from the model. To provide further assurance of the accuracy of the EPA hybrid model results, the Water Quality Simulation Package has been used to simulate tracer data and confirm the results (Ambrose et al., 1983; Ambrose and Wool, 2009; DiToro et al., 1981).

4.2.4. Status and Preliminary Data

The models described above are being used to determine potential impacts of treated wastewater discharges on downstream PWSs. Enough data have been identified to perform generic simulations for the steady-state mass balance simulations and hybrid empirical-numerical models with variable effluent concentration and plant discharge. For two WWTFs in Pennsylvania, USGS flow data have been compiled for segments of the rivers that reach downstream to drinking water intakes (50 to 100 miles downstream) for the two locations. These data will be used to generate realistic model inputs to assess, in a generic sense, the potential impacts of discharges from realistic treatment plants.

The EPA-developed hybrid empirical-numerical model has been favorably compared against a tracer experiment used by Jobson (1996) in developing the original empirical formulas. Calibration or other parameter adjustment was unnecessary for the hybrid model to produce accurate results. The EPA plans to compare the hybrid model to five more of the tracer experiments to cover the range of flow conditions used by Jobson (1996). Additionally, data from the more recent Yellowstone River experiment (McCarthy, 2009) are being prepared for testing the hybrid model. Similar comparisons of empirical to tracer experiments were performed by Reed and Stuckey (2002) for streams in the Susquehanna River Basin. The EPA Water Quality Simulation Package numerical model was set up to simulate the same tracer experiment performed for the hybrid model. Additional calibration is planned to refine the results from the Water Quality Simulation Package. After completing the evaluation of the hybrid model, the WWTF simulations will be completed.

4.2.5. Next Steps

A description of the EPA-developed empirical-numerical model and application of the empirical-numerical and mass balance models to tracer experiments is being developed by EPA scientists and are expected to be submitted for publication in a peer-reviewed journal. The results from testing of the models and the analysis of the WWTF effluent data will be included in another peer-reviewed journal article.

4.2.6. Quality Assurance Summary

The initial QAPP for "Surface Water Transport of Hydraulic Fracturing-Derived Waste Water" was approved by the designated EPA QA Manager on September 8, 2011 (US EPA, 2012s). The QAPP was subsequently revised and approved on February 22, 2012.

A TSA was conducted on March 1, 2012. The designated EPA QA Manager found the methods in use satisfactory and further recommendations for improving the QA process were unnecessary. An audit of data quality (ADQ) will be performed to verify that the quality requirements specified in the approved QAPP were met.

4.3. Water Availability Modeling

The EPA selected humid and semi-arid river basins as study areas for identifying potential impacts to drinking water resources from large volume water withdrawals (1 to 9 million gallons per well for the selected river basins) associated with hydraulic fracturing operations. This work is expected to address the research questions listed in Table 29.

Table 29. Research questions addressed by modeling water withdrawals and availability in selected river basins.

Water Cycle Stage	Applicable Research Questions
Water acquisition	• How much water is used in hydraulic fracturing operations, and what are the sources of this water? • How might water withdrawals affect short- and long-term water availability in an area with hydraulic fracturing? • What are the possible impacts of water withdrawals for hydraulic fracturing operations on local water quality?

4.3.1. Project Introduction

The volume of water needed in the hydraulic fracturing process for stimulation of unconventional oil and gas wells depends on the type of formation (e.g., coalbed, shale, or tight sands), the well construction (e.g., depth, length, vertical or directional drilling), and fracturing operations (e.g., fracturing fluid properties and fracture job design). Water requirements for hydraulic fracturing of CBM range from 50,000 to 250,000 gallons per well (Holditch, 1993; Jeu et al., 1988; Palmer et al., 1991; Palmer et al., 1993), although much larger volumes of water are produced during the lifetime of a well in order to lower the water table and expose the coal seam (ALL Consulting, 2003; S.S. Papadopulos & Associates Inc., 2007a, b). The water usage for hydraulic fracturing in shale gas plays is significantly larger than CBM reservoirs—2 to 4 million gallons of water are typically needed per well (API, 2010; GWPC and ALL Consulting, 2009; Satterfield et al., 2008). The volume of water needed for well drilling is understood to be much less, from 60,000 gallons in the Fayetteville Shale to 1 million gallons in the Haynesville Shale (GWPC and ALL Consulting, 2009). Water-based mud systems used for drilling vertical or horizontal wells generally require that fresh water (non-potable, potable, or treated) be used as makeup fluid, although wells can also be drilled using compressed air and oil-based fluids.

Water needed for hydraulic fracturing may come from multiple sources with varying quality. Sources may include raw surface and ground water, treated water from public water supplies, and water recycled from other purposes such as flowback and produced water from previous oil and gas operations or even acid mine drainage. The quality of water needed is dependent on the other chemicals in the fracturing fluid formulations, availability of water source, and the chemical and physical properties of the formation. The goal of this project is to investigate the water needs and sources to support hydraulic fracturing operations at the river basin and county spatial scales and to place this demand in the watershed context in terms of annual, seasonal, and monthly water availability.

The EPA recognizes the unique circumstances of the geography and geology of every unconventional oil and gas resource and has chosen two study sites to initially explore and identify the potential differences related to water acquisition. The study areas includes two river basins: the Susquehanna River Basin (SRB), located in the eastern United States (humid climate) and overlying the Marcellus Shale gas reservoir (Figure 20), and the Upper Colorado River Basin (UCRB), located in the western United States (semi-arid climate) and overlying the Piceance structural basin and tight gas reservoir (Figure 21). The EPA is calibrating and testing watershed models for the study; the SRB and UCRB watershed models were previously calibrated and tested in the EPA investigation of future climate change impacts on watershed hydrology (the "20 watersheds study") (Johnson et al., 2011).

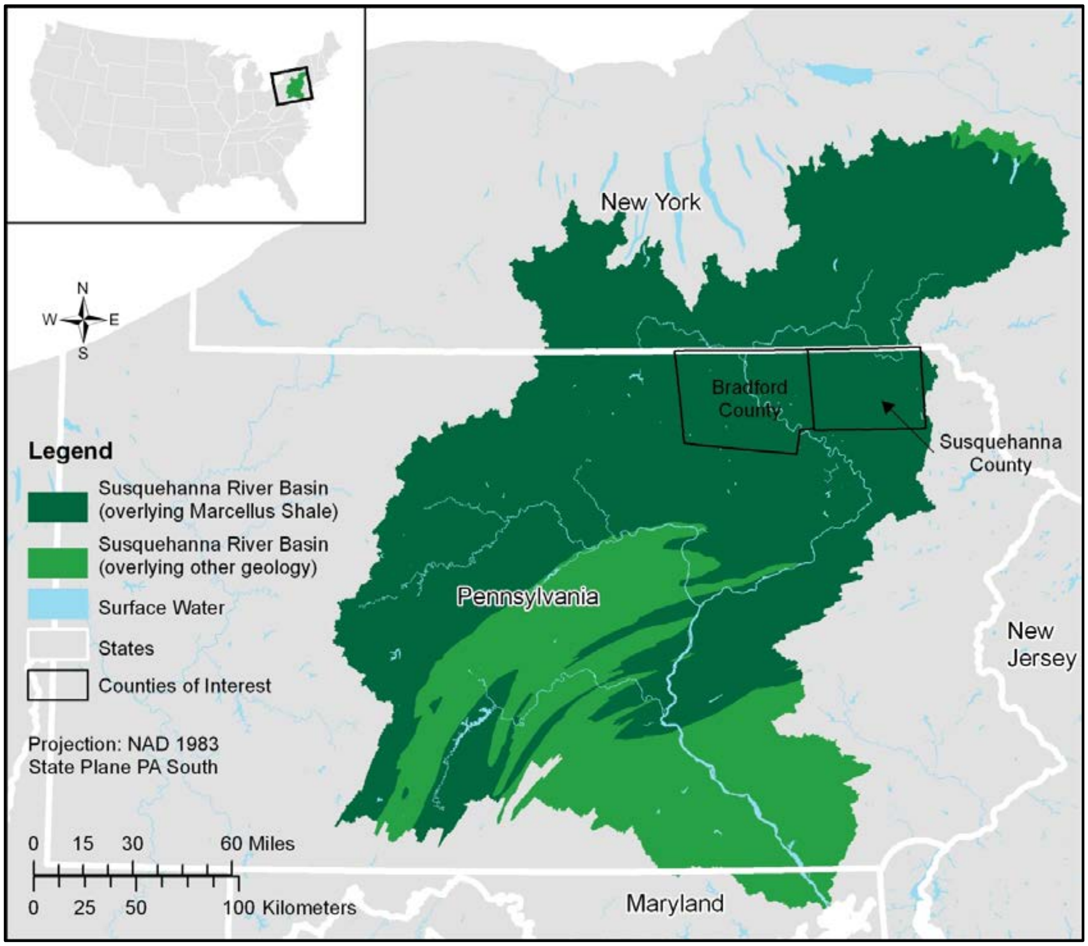

Figure 20. The Susquehanna River Basin, overlying a portion of the Marcellus Shale, is one of two study areas chosen for water availability modeling. Water acquisition for hydraulic fracturing will focus on Bradford and Susquehanna Counties in Pennsylvania. (GIS data obtained from ESRI, 2010a; US EIA, 2011e; US EPA, 2007.)

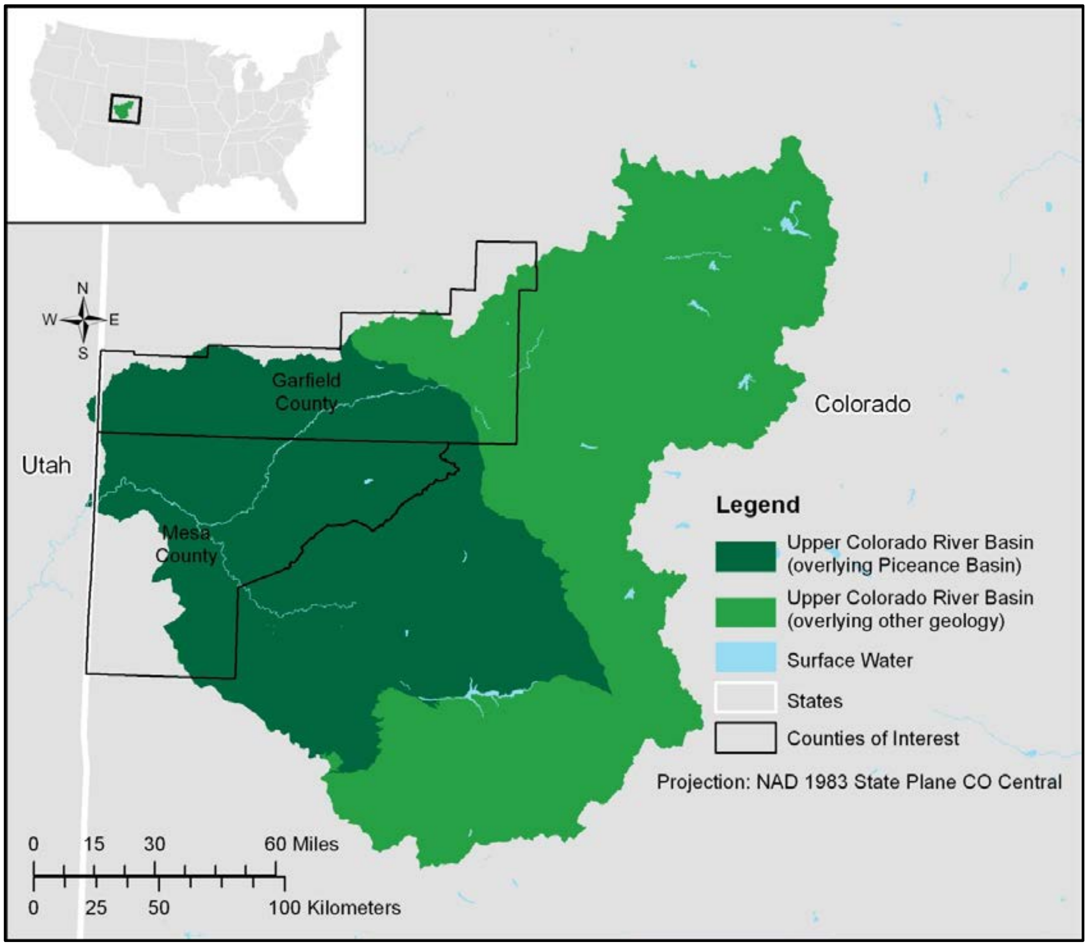

Figure 21. The Upper Colorado River Basin, overlying a portion of the Piceance Basin, is one of two river basins chosen for water availability modeling. Water acquisition for hydraulic fracturing will focus on Garfield and Mesa Counties in Colorado. (GIS data obtained from ESRI, 2010a; US EIA, 2011e; US EPA, 2007.)

In both study areas, the river watershed and its subsurface basin include the river flows and reservoir and aquifer storages based on the hydrologic cycle, geography, geology, and water uses. The EPA's goal is to explore future hypothetical scenarios of hydraulic fracturing use in the eastern and western study areas based on current understanding of hydraulic fracturing water acquisition and watershed hydrology. The EPA intends to characterize the significance, or insignificance, of hydraulic fracturing water use on future drinking water resources for the two study areas. The research will involve detailed representation of water acquisition supporting hydraulic fracturing in the Bradford County and Susquehanna County area in Pennsylvania and in the Garfield County and Mesa County areas of Colorado. These areas have concentrated hydraulic fracturing activity, as discussed below.

4.3.1.1. Susquehanna River Basin

Geography, Hydrology, and Climate. The SRB has over 32,000 miles of waterways, drains 27,510 square miles, and covers half of Pennsylvania and portions of New York and Maryland (Figure 20) (SRBC, 2006). On average, the SRB contributes 18 million gallons of water every minute (25,920 million gallons per day, or MGD) to the Chesapeake Bay (SRBC, 2006). The humid climate of the region experiences long-term average precipitation of 37 to 43 inches per year (McGonigal, 2005).

Oil and Gas Resources and Activity. Large portions of the SRB watershed are underlain by the Marcellus Shale formation, which is rich in natural gas. Estimates of recoverable and undiscovered natural gas from this formation range from 42 to 144 trillion cubic feet (Coleman et al., 2011) and production well development estimates for the next two decades range as high as 60,000 total wells drilled by 2030 (Johnson et al., 2010). The Pennsylvania Department of Environmental Protection reports that the number of drilled wells in the Marcellus Shale has been increasing rapidly. In 2007, only 27 Marcellus Shale wells were drilled in the state; in 2010 the number of wells drilled was 1,386. Data extracted from FracFocus[52] indicate that the total vertical depth of wells in Bradford and Susquehanna Counties is between 5,000 and 8,500 feet (mean of 6,360 feet) below ground surface, which implies that this depth range is the target production zone for the Marcellus Shale.

Water Use. The SRB supports a population of over 4.2 million people. Table 30 lists the estimated water use for the SRB and Bradford and Susquehanna Counties. The Susquehanna River Basin Commission estimates consumptive water use in five major categories, with PWSs consuming the greatest volume of water per day (325 MGD) followed by thermoelectric energy production (190 MGD) (Richenderfer, 2011). The greatest water withdrawals per day in Bradford and Susquehanna Counties are for drinking water (8.25 MGD for combined public and domestic use) and self-supplied industrial uses (4.59 MGD).

Table 30. Water withdrawals for use in the Susquehanna River Basin (Richenderfer, 2011) and Bradford and Susquehanna Counties, Pennsylvania (Kenny et al., 2009).

Use	Water Withdrawals (million gallons per day)	
	Susquehanna River Basin	Bradford and Susquehanna Counties, Pennsylvania
Public supply	325	4.59
Self-supplied domestic	Not reported	3.66
Irrigation (crop)	Not reported	0.110
Irrigation (golf courses)	Not reported	0.060
Self-supplied industrial	22.0	4.59
Livestock	Not reported	3.41
Thermoelectric	190 (energy production, non-gas)	0.00
Mining	10.0	0.10
Other	50.0 (recreation)	Not reported

Figure 22 displays the geographic distribution of PWSs in the SRB.[53]

[52] See Section 3.5 for additional information on the FracFocus data extraction and analysis research project.

[53] The location and type of drinking water supply is significant when represented in watershed hydrology models. The extraction of surface water is removed from the watershed model subbasin from its main river reach. The extraction of ground water is removed from the model subbasin from its ground water storage.

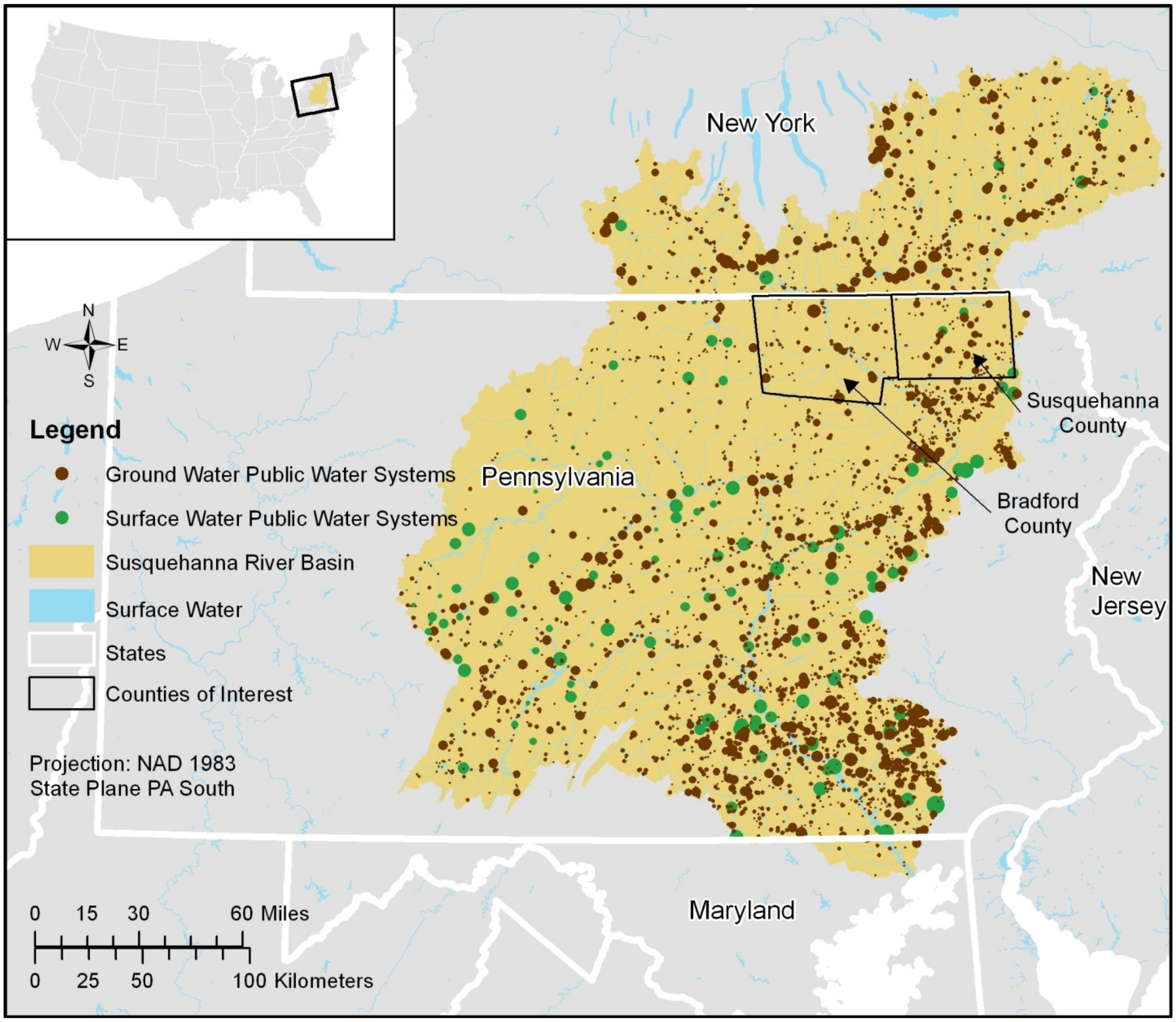

Figure 22. Public water systems in the Susquehanna River Basin (US EPA, 2011j). The legend symbol size for public water systems is proportional to the number of people served by the systems. For example, the smallest circle represents water systems serving 25 to 100 people and the largest circle represents systems serving over 100,000 people.

The Susquehanna River Basin Commission reports that the oil and gas industry consumed over 1.6 billion gallons of water for well drilling and hydraulic fracturing in the entire SRB from July 1, 2008, to February 14, 2011. If averaged over the entire time, this is roughly 1.7 MGD. This amount of water was used for approximately 1,800 gas production wells with about 550 wells hydraulically fractured by the end of 2010 (Richenderfer, 2011). The majority (65%) of the water came from direct surface water withdrawals, with smaller fractions from PWSs (35%) and ground water (very small). The average total volume of fluid used per well was 4.2 million gallons, with about 10% of the volume as treated flowback and 90% fresh water (Richenderfer, 2011). The average recovery of fluids was reported to be 8% to 12% of the injected volume within the first 30 days (Richenderfer, 2011).

Water use reported in FracFocus for Bradford and Susquehanna Counties ranges between 2 and 9 million gallons per well (median of 4.7 million gallons per well; (GWPC, 2012a)), consistent with data reported by the Susquehanna River Basin Commission.[54] In this part of the SRB, the wells are almost exclusively horizontal and producing from the Marcellus Shale. The operators are blending treated produced water into hydraulic fracturing fluids (Rossenfoss, 2011).

4.3.1.2. Upper Colorado River Basin

Geography, Hydrology, and Climate. The UCRB drains an area of 17,800 square miles and is characterized by high mountains in the east and plateaus and valleys in the west. The average discharge of the Colorado River near the Colorado-Utah state line is about 2.8 million gallons per minute (about 4,000 MGD) (Coleman et al., 2011). Precipitation ranges from 40 inches per year or more in the eastern part of the basin to less than 10 inches per year in the western part of the basin (Spahr et al., 2000).

Oil and Gas Resources and Activity. The UCRB has a long history of oil, gas, and coal exploration. The Piceance Basin is a source of unconventional natural gas and oil shale. The basin was originally exploited for its coal resources, and the associated CBM production peaked around 1992 (S.S. Papadopulos & Associates Inc., 2007a). The Upper Cretaceous Williams Fork Formation, a thick section of shale, sandstone, and coal, has been recognized as a significant source of gas since 2004 (Kuuskraa and Ammer, 2004). The wells producing gas from the Williams Fork are either vertically or directionally ("S"-shaped wells) drilled rather than horizontal. While the deeper Mancos Shale is considered a major resource for shale gas (Brathwaite, 2009), it must be exploited with horizontal drilling methods, and the economics are such that only prospecting wells are being drilled at this time (personal communication, Jonathan Shireman, Shaw Environmental & Infrastructure, May 1, 2012). Estimated reserves in coalbeds and unconventional tight gas reservoirs are nearly 84 trillion cubic feet (Tyler and McMurry, 1995).

Gas production activities occur in the following counties within the UCRB: Delta, Eagle, Garfield, Grand, Gunnison, Hinsdale, Mesa, Montrose, Ouray, Pitkin, Routt, Saguache, and Summit (COGCC, 2012b). Table 31 indicates that the greatest drilling activity has been in Garfield and Mesa Counties (Figure 21), where well completions increased steadily from 2000 (212 wells) to 2008 (2,725 wells), then dropped slightly to 1,160 wells in 2010 (COGCC, 2012b). The total vertical depth of wells in Garfield County and Mesa County as reported in FracFocus implies that the location of the target production zone(s) lies between 6,000 and 13,000 feet (mean of 8,000 feet) below ground surface.

[54] More information on FracFocus is available in Section 3.5.

Table 31. Well completions for select counties in Colorado within the Upper Colorado River Basin watershed (COGCC, 2012b).

County	Annual Well Completions from 2000 to 2010										
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Delta				8	5	8	3	2			4
Garfield	207	244	287	507	679	892	1269	1689	2255	1050	1139
Gunnison			2	3	2	1	11	8	2	4	2
Mesa	5	21	26	18	53	203	336	501	470	43	21
Montrose		4		2	2			3	4		1
Routt	10	21				8	5	2		4	1

Water Use. The UCRB supports a population of over 275,000 people. Table 32 lists the estimated water use for the UCRB and Garfield and Mesa Counties in Colorado. According to the USGS, the total water use in 2005 in the UCRB and Garfield and Mesa Counties was dominated by irrigation (1702 and 1200 MGD, respectively), followed by public and domestic water supply (60.4 and 29.6 MGD), and thermoelectric energy production (44 MGD) (Ivahnenko and Flynn, 2010; Kenny et al., 2009).

Table 32. Water withdrawals for use in the Upper Colorado River Basin (Ivahnenko and Flynn, 2010) and Garfield and Mesa Counties in Colorado (Kenny et al., 2009).

Use	Water Withdrawals (million gallons per day)	
	Upper Colorado River Basin	Garfield and Mesa Counties, Colorado
Public supply	58.6	29.2
Self-supplied domestic	1.81	1.35
Irrigation (crop)	1702	1200
Irrigation (golf courses)	8.00	3.50
Self-supplied industrial	2.71	1.05
Livestock	0.870	0.840
Thermoelectric	43.9 (non-consumptive)	43.9 (non-consumptive)
Mining	0.390	0.280
Other	Not reported	1.88 (aquaculture)

Figure 23 displays the distribution of public water systems in the basin. Interbasin water transfers, mining, urbanization, and agriculture are the principal human activities that potentially impact water quantity in the UCRB.

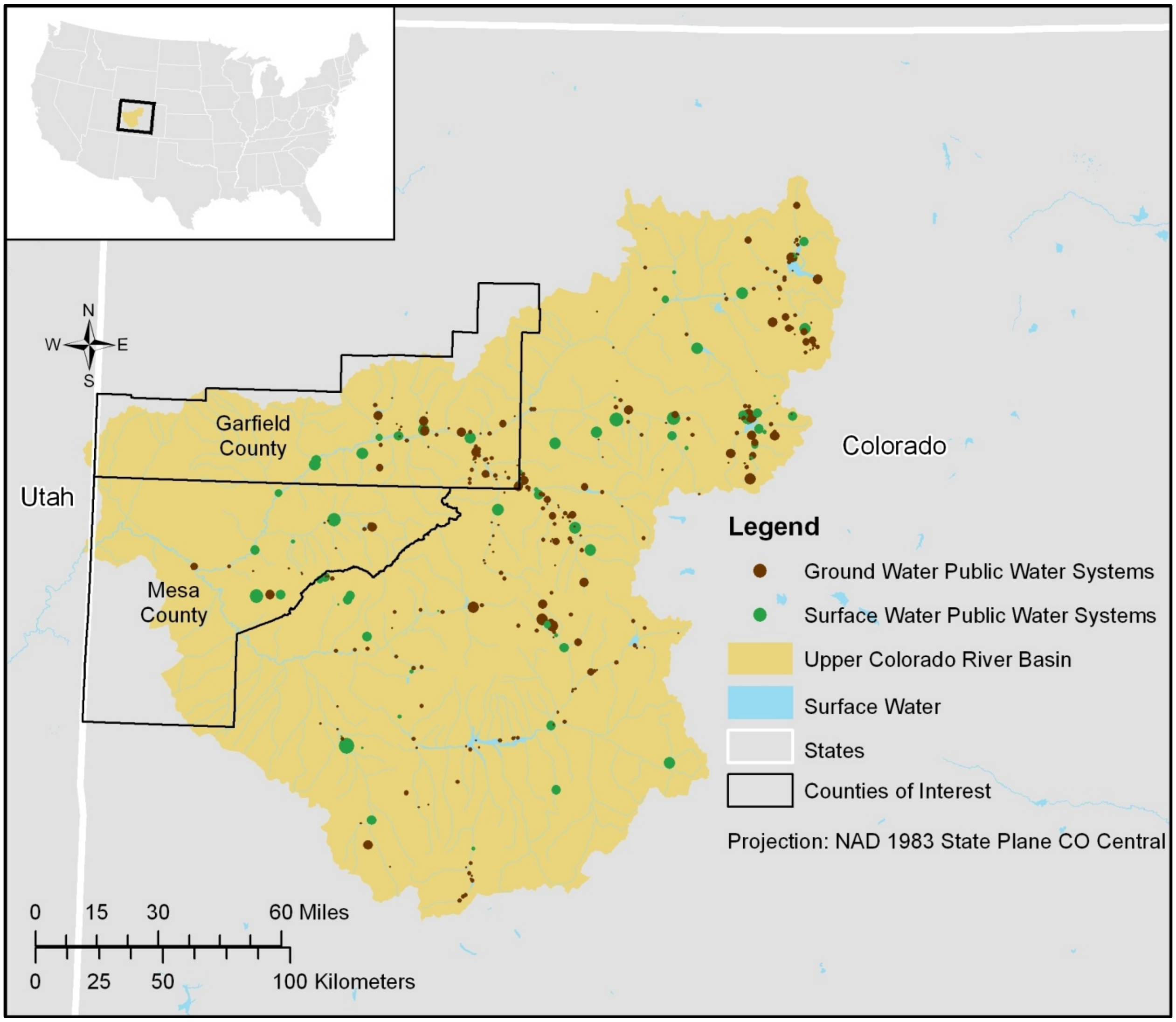

Figure 23. Public water systems in the Upper Colorado River Basin (US EPA, 2011j). The legend symbol size for public water systems is proportional to the number of people served by the systems. For example, the smallest circle represents water systems serving 25 to 100 people and the largest circle represents systems serving over 70,000 people.

The State of Colorado estimates that total annual statewide water demand for hydraulic fracturing associated with oil and gas wells increased from 4.5 billion gallons in 2010 to almost 4.9 billion gallons in 2011 (12.3 MGD in 2010 to almost 13.4 MGD in 2011), which parallels the increasing number of wells spudded, as shown in Table 33 (COGCC, 2012a). The amount of water demand was determined using the number of wells spudded (horizontal and vertical) multiplied by an average amount of water required for hydraulic fracturing per well type based on data reported in 2011. COGCC (2012a) estimates the average water use per well at about 1.6 million gallons in 2010 and 2011.

Table 33. Estimated total annual water demand for oil and gas wells in Colorado that were hydraulically fractured in 2010 and 2011 (COGCC, 2012a). Data for vertical and horizontal wells are not differentiated in the estimates and well spud dates.

Category	Year	
	2010	2011
Wells spudded	2,753	2,975
Estimated annual water demand (million gallons)	4,531	4,857
Estimated water use per well (million gallons)	1.65	1.63

Data extracted from FracFocus for Garfield and Mesa Counties shows water use per well between 1 and 9 million gallons (median 1.3 million gallons), which is consistent with the Colorado Oil and Gas Compact Commission data (COGCC, 2012a; GWPC, 2012a). In this part of the Piceance Basin (Figure 21), the majority of wells are vertically drilled and producing gas from the Williams Fork tight sandstones. Based on conversations with Berry Petroleum, Williams Production, Encana Oil and Gas, and the Colorado Field Office of the US Bureau of Land Management, the water used to fracture wells in this area is entirely recycled formation water that is recovered during production operations. Fresh water is used only for drilling mud, cementing the well casing, hydrostatic testing, and dust abatement and is estimated to be about 251,000 gallons per well (US FWS, 2008).

4.3.2. Research Approach

Watershed Models. In order to assess the impact of hydraulic fracturing water withdrawals on drinking water availability at watershed and county spatial scales as well as annual, seasonal, monthly, and daily time scales, the EPA is developing separate hydrologic watershed models for the SRB and UCRB. The models are based in part on the calibrated and verified watershed models (hereafter called the "foundation" models) of the EPA Global Change Research Program (Johnson et al., 2011), namely the Hydrologic Simulation Program FORTRAN (HSPF)[55] and the Soil and Water Assessment Tool (SWAT).[56] Both HSPF and SWAT are physically based, semi-distributed watershed models that compute changes in water storage and fluxes within drainage areas and water bodies over time. Each model can simulate the effect of water withdrawals or flow regulation on modeled stream or river flows. Key inputs for the models include meteorological data, land use data, and time series data representing water withdrawals. The models give comparable performance at the scale of investigation (Johnson et al., 2011).

Modeling of the SRB will be completed using the calibrated and tested HSPF. Since its initial development nearly 20 years ago, HSPF has been applied around the world; it is jointly sponsored by the EPA and the USGS, and has extensive documentation and references (Donigian Jr., 2005; Donigian Jr. et al., 2011). The choice of HSPF in the SRB, a subwatershed within the larger

[55] More information on the HSPF model including self-executable file, is available at http://www.epa.gov/ceampubl/swater/hspf/.

[56] More information on the SWAT model including self-executable file, is available at http://swat.tamu.edu/software/swat-model/.

Chesapeake Bay watershed, allows benchmarking to the peer-reviewed and community-accepted Chesapeake Bay Program watershed model.[57]

Modeling of the UCRB will be completed using the calibrated and tested SWAT. The SWAT is a continuation of over 30 years of modeling efforts conducted by the US Department of Agriculture's Agricultural Research Service and has extensive peer review (Gassman et al., 2007). SWAT is an appropriate choice in the less data-rich UCRB, where hydrological response units can be parameterized based on publicly available GIS maps of land use, topography, and soils.

The SRB and UCRB models will build on the "foundation" models and be updated to represent baseline and current watershed conditions. The baseline model will add reservoirs and major consumptive water uses for watershed conditions of the year 2000 for the SRB and 2005 for the UCRB. The baseline year predates the significant expansion of hydraulic fracturing in the basin (2007 for SRB, 2008 for UCRB) and corresponds with the USGS' water use reports (every five years since 1950) and the National Land Cover Dataset (Homer et al., 2007). The baseline models will represent the USGS's major water use categories, including the consumptive component of both PWS and domestic water use, and the other major water use categories (irrigation, livestock, industrial, mining, thermoelectric power). The snapshot of each watershed in the year 2010 will be the current model representation in both basins. The current models will include all water use categories from the baseline model plus hydraulic fracturing water withdrawals and refine the representation of PWS and hydraulic fracturing in county-scale focus areas—Garfield/Mesa Counties in Colorado and Bradford/Susquehanna Counties in Pennsylvania.

The foundation, baseline, and current watershed models will be exposed to the historical meteorology (precipitation, temperature) from National Weather Service gauges located within each watershed. The calibration and validation of the foundation, baseline, and current models will be checked by comparing goodness-of-fit statistics and through expert judgment of comparisons of observed and modeled stream discharges.

Key characteristics of model configuration include:

- Land use will be based on the 2001 National Land Cover Dataset (Homer et al., 2007). Land use data are used for segmenting the basin land area into multiple hydrologic response units, each with unique rainfall/runoff response properties. For the SWAT model, soil and slope data will also be used for defining unique hydrologic response units.
- Each basin will be segmented into multiple subwatersheds at the 10-digit hydrologic unit scale.[58]

[57] More information on the Chesapeake Bay Program watershed model is available at http://www.chesapeakebay.net/about/programs/modeling/53/.

[58] Hydrologic units refer to the Watershed Boundary Dataset developed through a coordinated effort by the USGS, the US Department of Agriculture, and the EPA. The intent of defining hydrologic units for the Watershed Boundary Dataset is to establish a baseline drainage boundary framework, accounting for all land and surface areas. Several levels of watershed are defined based on size. A 10-digit hydrologic unit is a level 5 watershed of average size 227 square miles (USDA, 2012).

- Observed meteorological data for water years 1972 to 2004 for SRB and 1973 to 2003 for UCRB will be applied to assess water availability over a range of weather conditions.
- The effect of reservoirs on downstream flows will be simulated using reservoir dimensions/operation data from circa 2000 from the Chesapeake Bay Program watershed model (Phase 5.3; (US EPA, 2010a)).
- Point source dischargers with NPDES-permitted flow rates of at least 1 MGD will be represented as sources of water on the appropriate stream reaches.
- Surface water withdrawals will be simulated for three unique water use categories: hydraulic fracturing water use, PWSs, and other. For the "other" category, the magnitude of withdrawals from modeled stream reaches will be based on water use estimates developed by the USGS (year 2000 for SRB; year 2005 for UCRB).[59]

Modeling Future Scenarios. The modeling effort will also simulate a snapshot of heightened annual hydraulic fracturing relative to the baseline and current condition models at levels that could feasibly occur over the next 30 years, based on recent drilling trends and future projections of natural gas production (US EIA, 2012; US EPA, 2012w). Because projections of future conditions are inherently uncertain, three separate scenarios will be simulated: business-as-usual, energy plus, and green technology. The scenarios assume distinct levels of natural gas drilling and hydraulic fracturing freshwater use and, therefore, apply distinct hydraulic fracturing water withdrawal time series to modeled stream reaches. Further, significant population growth is projected in Garfield/Mesa Counties, Colorado, over the next 30 years (US EPA, 2010c), where natural gas extraction in the UCRB has recently been concentrated. Therefore, the UCRB future scenarios also consider a potential increase in PWS surface withdrawals in the basin. The balance between surface water availability and demand depicted in each scenario's annual snapshot of water use will be assessed across a range of weather conditions (i.e., drought, dry, wet, and very wet years based on the historical record). A description of each scenario, and the methods used for scenario development, are provided below and in Tables 34 and 35.

[59] The USGS water use estimates can be found at http://water.usgs.gov/watuse/.

Table 34. Data and assumptions for future watershed availability and use scenarios modeled for the Susquehanna River Basin. Current practices for water acquisition and disposal are tracked by the Susquehanna River Basin Commission (SRBC).

Model Assumptions	Future Scenarios		
	Business as Usual	Energy Plus	Green Technology
Hydraulic fracturing well deployment	Current well inventory and future deployment schedules and play-level development projections*	Maximum projected development of gas reserves*	Current well inventory and future deployment schedules and play-level development projections*
Hydraulic fracturing water management practices	Current practices for water acquisition, production and disposal tracked by SRBC†	Current practices for water acquisition, production and disposal tracked by SRBC†	Increased recycling of produced water for hydraulic fracturing†

* US EPA, 2012w; USGS, 2011c
† SRBC, 2012

Table 35. Data and assumptions for future watershed availability and use scenarios modeled for the Upper Colorado River Basin.

Model Assumptions	Future Scenarios		
	Business as Usual	Energy Plus*	Green Technology*
Hydraulic fracturing well deployment	Current well inventory and future deployment schedules and play-level development projections†	Maximum projected development of gas reserves†	Maximum projected development of gas reserves†
Hydraulic fracturing water management practices	Current practices for water acquisition, production and disposal estimated for UCRB§	Current practices for water acquisition, production and disposal estimated for UCRB§	Increased recycling of produced water for drilling§

* Reflects 2040 population increase (US EPA, 2010c) and corresponding change in PWS demand.
† US EIA, 2011b, 2012; US EPA, 2012w; USGS, 2003
§ US FWS, 2008

Future drilling patterns in the SRB and UCRB are assessed from National Energy Modeling System (NEMS) regional projections of the number of wells drilled annually from 2011to 2040 in shale gas (SRB) and tight gas (UCRB) plays (US EIA, 2012; US EPA, 2012w). Based on analysis of NEMS well projections and undiscovered resources in the Marcellus Shale (Coleman et al., 2011), peak annual drilling in the SRB could exceed the recent high in 2011 by as much as 50%. In the UCRB, analysis of NEMS well projections and undiscovered tight gas resources in the Piceance Basin (USGS, 2003) suggest that the 2008 peak level of drilling in the basin could be repeated in the late 2030s, when a growing population would exert a higher demand for freshwater. The future scenarios will incorporate these projections, with high-end estimates of the number of wells drilled/fractured applied in the energy plus scenario.

The volume of surface water required for drilling and hydraulic fracturing varies according to local geology, well characteristics, and the amount of recycled water available for injection. In the SRB, 2008 to 2011 water use data (SRBC, 2012) show that, on average, 13% of total water injected for hydraulic fracturing is composed of recycled produced water or wastewater. Per well surface water use in the SRB business as usual and energy plus scenarios will therefore be established as 87% of the 4 million gallons of water used for hydraulic fracturing, or 3.5 million gallons. The SRB green technology scenario reflects a condition of increased water recycling, where the 90th percentile of current recycled water amount (29%) becomes the average. Per well surface water use in the SRB green technology scenario will therefore be established as 71% of the 4 million gallons of water used for hydraulic fracturing, or 2.8 million gallons.

In the UCRB, 100% recycled water use is typical for hydraulic fracturing of tight sandstones (personal communication, Jonathan Shireman, Shaw Environmental & Infrastructure, May 7, 2012). Surface water is acquired for well drilling and cementing (0.18 million gallons), dust abatement (0.03 million gallons), and hydrostatic testing (0.04 million gallons) only (US FWS, 2008). Per well surface water use in the UCRB business as usual and energy plus scenarios will therefore be 0.25 million gallons. For the UCRB green technology scenario, surface water will be assumed to be acquired for well drilling and cementing only (0.18 million gallons per well).

Following the development of water withdrawal datasets for each scenario, model output will be reviewed to assess the impacts of water acquisition for hydraulic fracturing on drinking water supplies by evaluating annual and long-term streamflow and water demand, and identifying short-term periods (daily to monthly) in which water demand exceeds streamflow. Since many public water supplies originate from ground water sources, simulated ground water recharge will also be computed. Results will be compared among the three scenarios to identify noteworthy differences and their implications for future management of hydraulic fracturing-related water withdrawals.

4.3.3. Status and Preliminary Data

Existing water use information for hydraulic fracturing has been collected from the Susquehanna River Basin Commission and the Colorado Oil and Gas Compact Commission by Shaw Environmental Technologies. The data underwent a QA review before submission to the modeling teams of The Cadmus Group, Inc. The models are being calibrated and validated. The future scenarios are being designed, with model simulations to follow. Work is underway and will be published in peer-reviewed journals when completed.

4.3.4. Quality Assurance Summary

The QAPP, "Modeling the Impact of Hydraulic Fracturing on Water Resources Based on Water Acquisition Scenarios (Version 1.0)," contracted through The Cadmus Group, Inc., was accepted on February 8, 2012 (Cadmus Group Inc., 2012a). A technical directive/contract modification dated April 25, 2012, modifies the scope of the project but not the procedures. Additionally, there is a pending QAPP revision that adapts the scope to the contract modification.

A TSA of The Cadmus Group, Inc., contract was performed by the designated EPA QA Manager on June 14, 2012. The methods in use were found to be satisfactory and further recommendations for improving the QA process were unnecessary. Work performed and scheduled to be performed was within the scope of the project.

The interim progress report "Development and Evaluation of Baseline and Current Conditions for the Susquehanna River Basin," received on June 19, 2012, was found to be concise but detailed enough to meet the QA requirements, as expressed in the QAPP, its revision, and the contract modification/technical directive. The same was true for the interim progress report "Impact of Water Use and Hydro-Fracking on the Hydrology of the Upper Colorado River Basin," submitted on July 2, 2012.

5. Laboratory Studies

The laboratory studies are targeted research projects designed to improve understanding of the ultimate fate and transport of selected chemicals, which may be components of hydraulic fracturing fluids or naturally occurring substances released from the subsurface during hydraulic fracturing. This chapter includes progress reports for the following projects:

5.1. Source Apportionment Studies

5.1.1. Relationship to the Study

The EPA is combining data collected from samples of wastewater treatment facility discharges and receiving waters with existing modeling programs to identify the proportion of hydraulic fracturing wastewater that may be contributing to contamination at downstream public water system intakes. This work has been designed to help inform the answer to the research question listed in Table 36.

Table 36. Secondary research questions addressed by the source apportionment research project.

Water Cycle Stage	Applicable Research Questions
Wastewater treatment and waste disposal	What are the potential impacts from surface water disposal of treated hydraulic fracturing wastewater on drinking water treatment facilities?

5.1.2. Project Introduction

The large national increase in hydraulic fracturing activity has generated large volumes of hydraulic fracturing wastewater for treatment and disposal or recycling. In some cases, states have allowed hydraulic fracturing wastewater to be treated by WWTFs with subsequent discharge to rivers. Most WWTFs are designed to filter and flocculate solids, as well as consume biodegradable organic species associated with human and some commercial waste. Very few facilities are designed to manage the organic and inorganic chemical compounds contained in hydraulic fracturing wastewater.

Public water supply intakes may be located in river systems downstream from WWTFs and a variety of other industrial and urban discharges, and it is critical to evaluate sources of contamination at those drinking water intakes. Elevated bromide and chloride concentrations are of particular concern in drinking water sources due to the propensity of bromides to react with organic compounds to produce THMs and other DBPs during drinking water treatment processes (Plewa and Wagner, 2009). High TDS levels—including bromide and chloride—have been detected in the Monongahela River in 2008 and the Youghiogheny River in 2010 (Lee, 2011; Ziemkiewicz, 2011). The source and effects of these elevated concentrations remains unclear.

This project's overall goal is to establish an approach whereby surface water samples may be evaluated to determine the extent to which hydraulic fracturing wastewaters (treated or untreated) may be present, and to distinguish whether any elevated bromide and chloride in those samples may be due to hydraulic fracturing or other activities. To accomplish this goal, the EPA is: (1) quantifying the inorganic chemical composition of discharges in two Pennsylvania river systems from WWTFs that accept and treat flowback and produced water, coal-fired utility boilers, acid mine drainage, stormwater runoff of roadway deicing material, and other industrial sources; (2) investigating the impacts of the discharges by simultaneously collecting multiple upstream and downstream samples to evaluate transport and dispersion of inorganic species; and (3) estimating the impact of these discharges on downstream bromide and chloride levels at PWS intakes using mathematical models.

5.1.3. Research Approach

The "Quality Assurance Project Plan for Hydraulic Fracturing Wastewater Source Apportionment" provides a detailed description of the research approach (US EPA, 2012q). Briefly, water samples are being collected at five locations on two river systems; each river has an existing WWTF that is currently accepting hydraulic fracturing wastewater for treatment. Source profiles for significant sources such as hydraulic fracturing wastewater, WWTF effluent, coal-fired utility boiler discharge, acid mine drainage, and stormwater runoff from roadway deicing will be developed from samples collected from these sources during the study. Computer models will then be used to compare data from these river systems to chemical and isotopic composition profiles obtained from potential sources.

Three two-week intensive sampling events were conducted to assess river conditions under different flow regimes: spring, summer, and fall 2012. As shown in Table 37, the amount of water in the river has historically been highest in the spring, resulting in the dilution of pollutants, and the summer and fall seasons typically have decreased stream flow, which may result in elevated concentrations due to less dilution (USGS, 2011a, b). USGS gauging stations near the WWTFs will be used to measure the flow rate during the three sampling periods.

Table 37. Historical average of monthly mean river flow and range of monthly means from 2006 through 2011 for two rivers in Pennsylvania where the EPA collects samples for source apportionment research (USGS, 2011a, b).

Month	Average of Monthly Mean River Flow from 2006 Through 2011 (cubic feet per second)		Range of Monthly Means from 2006 Through 2011 (cubic feet per second)	
	Allegheny River	Blacklick Creek	Allegheny River	Blacklick Creek
May	12,100	357	7,330–28,010	220.2–479.7
July	5,740	134	2,164–10,840	65.8–198.2
September	4,940	174	2,873–13,560	48.8–520.0

During each sampling event, automatic water samplers (Teledyne Isco, model 6712) at each site collect two samples daily—morning and afternoon—based on the PWS and WWTF operations schedule. The samples are stored in the sampler for one to four days, depending on the site visit schedule. Each river is sampled in five locations, as shown in Table 38. The first sampling device downstream of the WWTF is far enough downstream to allow for adequate mixing of the WWTF effluent and river water. The second downstream sampling device is between the first downstream sampling location and the closest PWS intake. The locations of the samplers downstream of the WWTF also take into account the presence of other significant sources, such as coal-fired utility boiler and acid mine drainage discharges, and allow for the evaluation of their impacts.

Table 38. Distance between sampling sites and wastewater treatment facilities on two rivers where the EPA collects samples for source apportionment research.

Site	Distance Between Sampling Sites (kilometers)	
	Allegheny River	Blacklick Creek
Site 1 (upstream)	-1.6	-1.2
Site 2 (wastewater treatment facility)	0	0
Site 3 (downstream)	12.2	2.7
Site 4 (downstream)	44.1	43.1
Site 5 (public water system intake)	52.3	88.6

5.1.3.1. Sample Analyses

The EPA will analyze the river samples and effluent samples according to existing EPA methods for the suite of elements and ions listed in Table 39. Inorganic ions (anions and cations) are being determined by ion chromatography. Inorganic elements are being determined using a combination of inductively coupled plasma optical emission spectroscopy for high-concentration elements and high-resolution magnetic sector field inductively coupled plasma mass spectrometry for low concentration elements. Additionally, the characteristic strontium (Sr) ratios ($^{87}Sr/^{86}Sr$; 0.7101–0.7121) in Marcellus Shale brines are extremely sensitive tracers, and elevated concentrations of readily water soluble strontium are present in the hydraulic fracturing wastewaters (Chapman et al., 2012). Isotope analyses for $^{87}Sr/^{86}Sr$ are being conducted on a subset (~20%) of samples by thermal ionization mass spectrometry to corroborate source apportionment modeling results.

Table 39. Inorganic analyses and respective instrumentation planned for source apportionment research. The EPA will analyze samples from two rivers and effluent discharged from wastewater treatment facilities located on each river. Instruments used for analysis include high-resolution magnetic sector field inductively coupled plasma mass spectrometry (HR-ICP-MS), ion chromatography (IC), inductively coupled plasma optical emission spectroscopy (ICP-OES), and thermal ionization mass spectroscopy (TIMS).

Element	Instrument Used	Element	Instrument Used
Ag*	HR-ICP-MS	Sb*	HR-ICP-MS
Al*	ICP-OES	Sc	HR-ICP-MS
As*	HR-ICP-MS	Se*	HR-ICP-MS
B*	ICP-OES	Si	ICP-OES
Ba*	ICP-OES	Sm	HR-ICP-MS
Be*	HR-ICP-MS	Sn	HR-ICP-MS
Bi	HR-ICP-MS	Sr*	HR-ICP-MS
Ca*	ICP-OES	Tb	HR-ICP-MS
Cd*	HR-ICP-MS	Th	HR-ICP-MS
Ce	HR-ICP-MS	Ti*	ICP-OES
Co*	HR-ICP-MS	Tl*	HR-ICP-MS
Cr*	HR-ICP-MS	U	HR-ICP-MS
Cs*	HR-ICP-MS	V*	HR-ICP-MS
Cu*	ICP-OES, HR-ICP-MS	W	HR-ICP-MS
Fe*	ICP-OES, HR-ICP-MS	Y	HR-ICP-MS
Gd	HR-ICP-MS	Zn*	ICP-OES
Ge	HR-ICP-MS	**Isotope Ratio**	**Instrument Used**
K*	ICP-OES	$^{87}Sr/^{86}Sr$*	TIMS
La	HR-ICP-MS	**Ion**	**Instrument Used**
Li*	ICP-OES	Ca^{2+} *	IC
Mg*	ICP-OES	K^{+} *	IC
Mn*	ICP-OES, HR-ICP-MS	Li^{+} *	IC
Mo*	HR-ICP-MS	Mg^{2+} *	IC
Na*	ICP-OES	NH_4^{+}	IC
Nd	HR-ICP-MS	Na^{+} *	IC
Ni*	HR-ICP-MS	Br^{-} *	IC
P*	ICP-OES	Cl^{-} *	IC
Pb*	HR-ICP-MS	F^{-} *	IC
Pd	HR-ICP-MS	NO_2^{-}	IC
Pt	HR-ICP-MS	NO_3^{2-}	IC
Rb	HR-ICP-MS	PO_4^{3-}	IC
S*	ICP-OES	SO_4^{2-} *	IC

* Chemicals detected in flowback and produced water. See Table A-3 in Appendix A.

Although the majority of the species that are being quantified in this study have been identified in flowback or produced water,[60] the species relationships and relative quantities of the species in

[60] See Table A-3 in Appendix A.

other sources (i.e., coal-fired utility boiler and acid mine drainage discharges) will differ (Chapman et al., 2012). This will allow the models described below to distinguish among the contributions from each source type.

5.1.3.2. Source Apportionment Modeling

The EPA is using the data gathered through the analyses described above to support source apportionment modeling. This source apportionment effort will use peer-reviewed receptor models to identify and quantify the relative contribution of different contaminant source types to environmental samples.[61] In this case, river samples collected near PWS intakes are being evaluated to discern the contributing sources (e.g., hydraulic fracturing wastewater or acid mine drainage) of bromide and chloride to those stream waters. Receptor models require a comprehensive analysis of environmental samples to provide a sufficient number of constituents to identify and separate the impacts of different source types. Analysis of major ions and inorganic trace elements (Table 39) will accomplish the needs for robust receptor modeling. Contaminant sources may be distinguished by unique ranges of chemical species and their concentrations, and the models provide quantitative estimates of the source type contributions along with robust uncertainty estimates.

EPA-implemented models and commercial off-the-shelf software are being used to analyze the data from this particular study (e.g., Unmix, Positive Matrix Factorization, chemical mass balance). These models have previously been used to evaluate a wide range of environmental data for air, soil, and sediments (Cao et al., 2011; Pancras et al., 2011; Soonthornnonda and Christensen, 2008), and are now being used for emerging issues, such as potential impacts to drinking water from hydraulic fracturing.

5.1.4. Status and Preliminary Data

The EPA completed the two-week spring, summer, and fall intensive sampling periods beginning on May 16, July 20, and September 19, 2012, respectively. The EPA collected 206, 198, and 209 samples during the spring, summer, and fall intensives, consisting of WWTF-treated discharge, river samples, raw hydraulic fracturing wastewater, and acid mine drainage. The data quality objectives (US EPA, 2012q) of 80% valid sample collection were met for both the spring (>85%) and summer (>96%) measurement intensives. Preparation work for the extraction and filtration of spring intensive samples for inductively coupled plasma optical emission spectroscopy and high-resolution magnetic sector field inductively coupled plasma mass spectrometry is ongoing.

Table 40 shows the median discharge concentrations of chloride, bromide, sulfate, sodium, and conductivity in effluent from the two monitored WWTFs (prior to discharge and dilution in the rivers) during the spring sampling period; Table 40 also shows the conductivity of the effluent. Median chloride and sodium concentrations at Discharge A (Allegheny River) were almost 50% less than concentrations found at Discharge B (Blacklick Creek). High levels of sodium chloride (>20,000 milligrams per liter) are present in the discharge from both facilities (A and B). Bromide concentrations are roughly 35% lower at Discharge A than Discharge B.

[61] The receptor model, Positive Matrix Factorization, was peer-reviewed in 2007 (version 1.1) and 2011 (version 4.2), and Unmix (version 5.0) underwent peer review in 2007.

Table 40. Median concentrations of selected chemicals and conductivity of effluent treated and discharged from two wastewater treatment facilities that accept oil and gas wastewater. Discharge A is located on the Allegheny River and Discharge B is located on Blacklick Creek, both in Pennsylvania. The EPA collected samples beginning on May 16, 2012.

Measurement	Median Concentration (milligrams per liter)	
	Discharge A	Discharge B
Chloride	49,875	97,963
Bromide	506	779
Sulfate	679	976
Sodium	20,756	38,394
Conductivity (millisiemens per centimeter)	110	168

The differences in the discharge concentrations are due to a combination of the treatment processes and unique regional chemical characteristics of oil and gas wastewater being treated at each of the facilities. Additionally, the discharge from the WWTFs is diluted into surface waters with very different median flows, with the USGS provisional median flows for the river sampling events reported as 15,158 and 2,531 cubic feet per second for the Allegheny River in spring (May 16–30, 2012) and summer (July 20–August 3, 2012), respectively (USGS, 2012a); and 642 and 35 cubic feet per second for Blacklick Creek in spring (May 17–31, 2012) and summer (July 21–August 4, 2012), respectively (USGS, 2012b). The relative impact of these seasonal dilution scenarios from the WWTF discharges will be determined with the measured chemical species.

5.1.5. Next Steps

Analysis of field and source samples will continue in order to obtain the necessary data for source apportionment modeling. Once sample analyses are completed, data will be used as input to the receptor models described above to identify and quantify the sources of chloride and bromide at PWS intakes.

5.1.6. Quality Assurance Summary

The “QAPP for Hydraulic Fracturing Wastewater Source Apportionment” was approved on April 17, 2012 (US EPA, 2012q). A TSA of the field sampling was conducted on May 3, 2012, by the designated EPA QA Manager. There were two findings and two observations. The agreed-upon corrective actions were reported in writing to the researchers and management on May 17, 2012, and have been implemented by the research team.

One finding identified the need to verbally “call back” measurement numbers between the sampler and scribe to confirm values when collecting short-term river measurements. The researchers instituted the verbal confirmation immediately in the field as suggested by the auditor. The second finding highlighted the need to accurately track the sample cooler temperature. A corrective action was implemented to improve the monitoring/recording of sample shipping cooler temperatures by ordering new National Institute of Standards and Technology traceable logging temperature loggers and keeping the loggers with the samples throughout the day in order to record accurate data of the temperatures at which the samples are stored and shipped. The new loggers were received and used in the field on May 8, 2012.

During the audit, it was observed that the custody seals may not have offered a level of security necessary for the project. The field team had already identified this potential problem and had ordered different tamper-resistant seals before the field trip. The new seals (NIK Public Safety Tamperguard brand evidence tape) have been in use since they were received on May 10, 2012. The second observation during the audit was the need to document the reasoning of changes performed to standard operating procedures. The researchers have documented all the changes performed as well as the logic and reasoning of the changes in the field laboratory notebooks. Most modifications to the procedures were related to procedural adjustments made as a result of the field site characteristics, which were slightly different from the field site characteristics used to field-test the procedures in North Carolina. The documents also included updates to points of contact, references, and added text for clarification (e.g., river velocity measurements). Revisions reflecting these changes have been made to the QAPP and four SOPs based on the spring intensive field experience and the TSA. The revised version of the QAPP and four SOPs were approved on June 29, 2012. These updates do not impact the original data quality objectives.

The researchers are following the QA procedures described in the QAPP and the standard operating procedures. In accordance to the QAPP, a TSA was performed on July 16 and 17, 2012, to evaluate laboratory operations. The designated EPA QA Manager reviewed the ion chromatography and high-resolution magnetic sector field inductively coupled plasma mass spectrometer analyses, data processing, storage, sample receiving and chain of custody procedures. The audit identified two observations and one best practice. One of the observations highlighted the need for a process that would ensure proper transcription of the data from the ion chromatography instrument to the report file. To reduce uncertainty and potential transcription errors, the analyst developed a process to export the data produced by the instrument in a text file instead of copying and pasting the data to a separate file. Another observation was the need to include performance evaluation samples in the analytical set. The performance evaluation samples will be analyzed in addition to the other quality controls already in place, which include blanks, duplicates, standard reference materials, and continuing calibration verification. The performance evaluation audit is being scheduled as specified in the QAPP. The blind performance evaluation samples will be analyzed with the regular samples and the data reported back to the QA Manager of the organization providing the blind performance evaluation samples. The best practice identified by the auditor was the tracking system, which uses a scanner and bar codes to track sampling bottles through the whole process: preparation, deployment to/from the field, sample analysis, and data reporting. The quality control (QC) procedures described in the QAPP have been followed in all instances. Besides the two TSAs performed and the performance evaluation audit, an ADQ is being coordinated by the designated EPA QA Manager. The source apportionment modeling will be described in a separate modeling QAPP. A TSA will be scheduled in 2013 for the modeling component of the study.

5.2. Wastewater Treatability Studies

5.2.1. Relationship to the Study

The EPA is conducting laboratory experiments to assess the efficacy of conventional wastewater treatment processes on selected chemicals found in hydraulic fracturing wastewater to provide data to inform the research question posed in Table 41. The results of the water treatability experiments also complement the surface water modeling research project (see Section 4.2).

Table 41. Secondary research questions addressed by the wastewater treatability laboratory studies.

Water Cycle Stage	Applicable Research Questions
Wastewater treatment and waste disposal	How effective are conventional POTWs and commercial treatment systems in removing organic and inorganic contaminants of concern in hydraulic fracturing wastewater?

5.2.2. Introduction

Hydraulic fracturing wastewater, including flowback and produced water, is generally disposed of through underground injection in Class II UIC wells or treatment by a WWTF followed by surface water discharge. A generalized diagram for the onsite flow of water is given in Figure 24. A US Department of Energy report provides a state-by-state description of costs, regulations, and treatment/disposal practices for hydraulic fracturing wastes, including wastewater (Puder and Veil, 2006).

Wastewater may be treated at a WWTF, such as a POTW or centralized waste treatment facility (CWT). This project focuses on the efficacy of treatment processes at POTWs and CWTs, since discharge of treated wastewater to surface waters provides an opportunity for chemicals found in the effluent to be transported to downstream PWS intakes. This project will also explore treatment processes used for reuse of hydraulic fracturing wastewater.

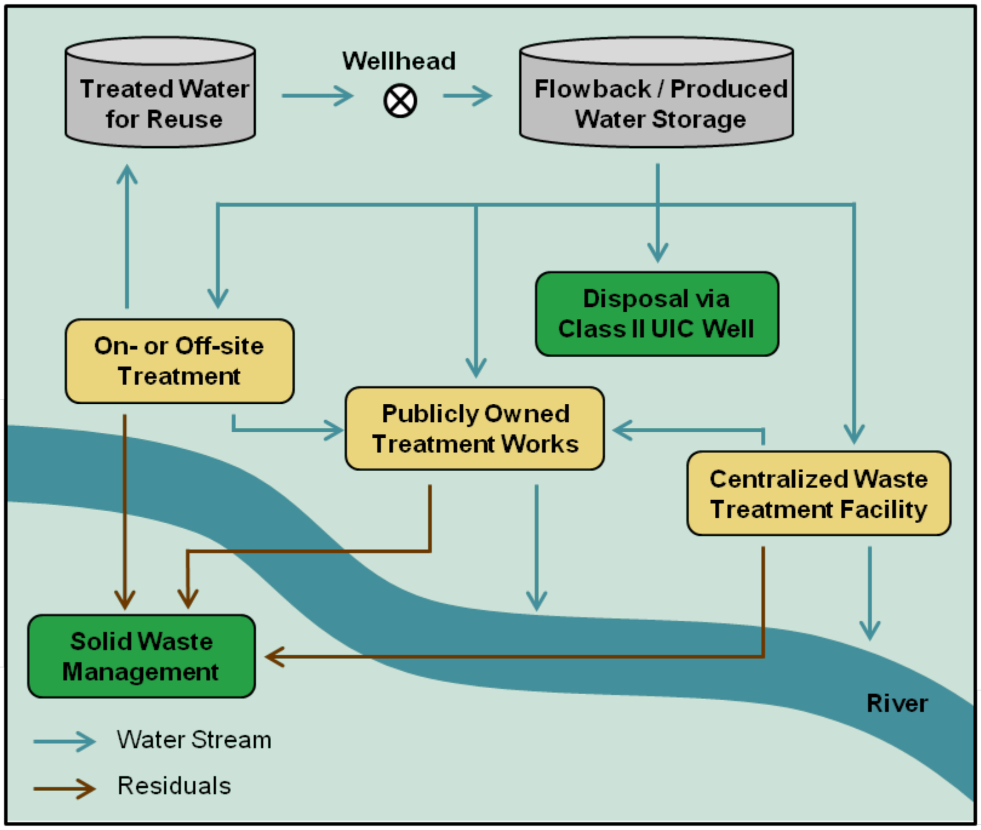

Figure 24. Hydraulic fracturing wastewater flow in unconventional oil and gas extraction. Flowback and produced water (collectively referred to as "hydraulic fracturing wastewater") is typically stored onsite prior to disposal or treatment. Hydraulic fracturing wastewater may be disposed of through Class II underground injection control (UIC) wells or through surface water discharge following treatment at wastewater treatment facilities, such as publicly owned treatment works or centralized waste treatment facilities. Wastewater may be treated on- or offsite prior to reuse in hydraulic fracturing fluids.

5.2.2.1. Publicly Owned Treatment Works Treatment Processes

Conventional POTW treatment processes are categorized into four groups: primary, secondary, tertiary, and advanced treatment. A generalized flow diagram is presented in Figure 25.

Primary treatment processes remove larger solids and wastewater constituents that either settle or float. These processes include screens, weirs, grit removal, and/or sedimentation and flotation (e.g., primary clarification). Secondary treatment processes typically remove biodegradable organics by using microbial processes (e.g., "bioreactor" in Figure 25) in fixed media (e.g., trickling filters) or in the water column (e.g., aeration basins). There is typically another settling stage in the secondary treatment process where suspended solids generated in the aeration basin are removed through settling ("secondary clarifier" in Figure 25). In some systems, tertiary or advanced treatment ("filter and UV disinfection" in Figure 25) may be applied as a polishing step to achieve a particular end use water quality (e.g., for reuse in irrigation).The POTW then discharges the treated effluent to surface water, if recycling or reuse is not intended. Solid residuals formed as byproducts of the treatment processes may contain metals, organics, and radionuclides that were removed from the water. Residuals are typically de-watered and disposed of via landfill, land application, or incineration.

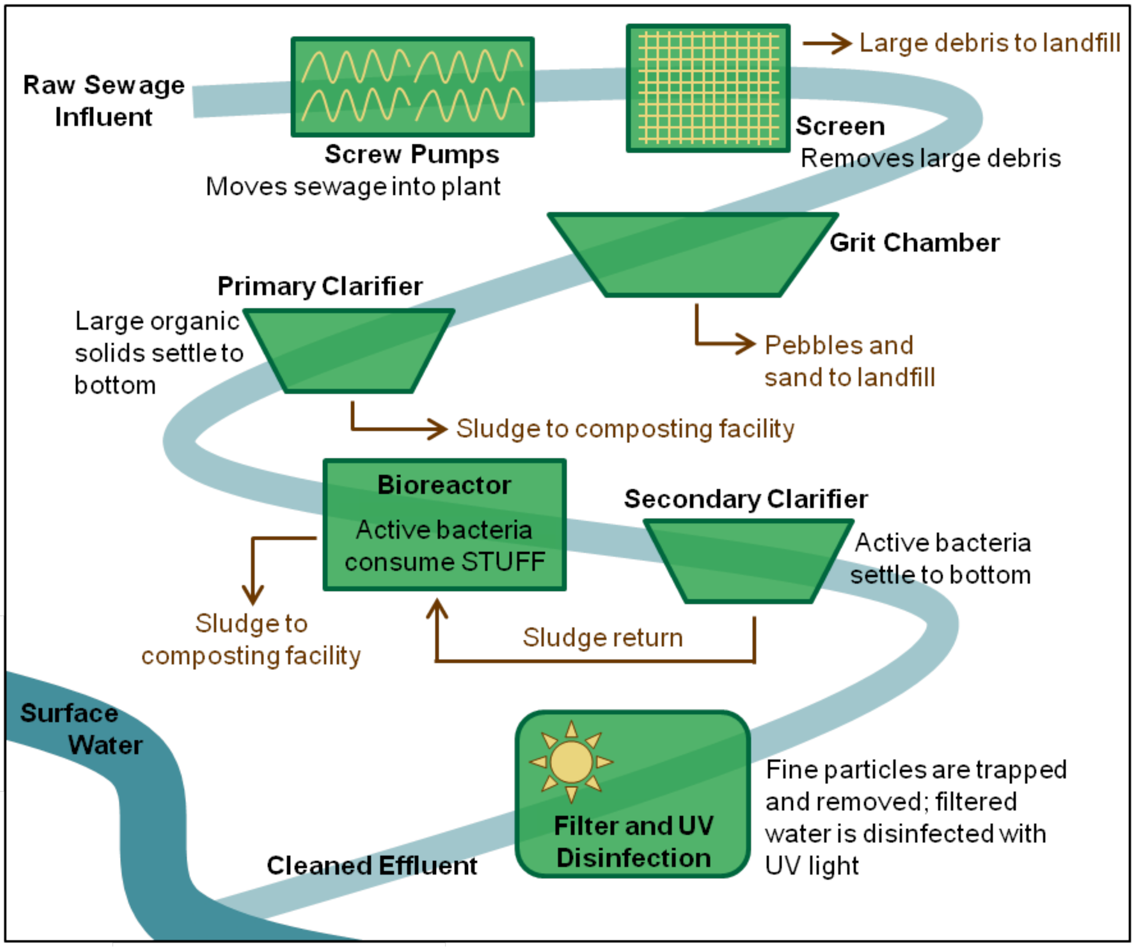

Figure 25. Generalized flow diagram for conventional publicly owned works treatment processes. See the text for descriptions of primary, secondary, tertiary, and advanced treatment processes.

The exact number of POTWs currently accepting hydraulic fracturing wastewater is not known. In Pennsylvania, where gas production from the Marcellus Shale is occurring, approximately 15 POTWs were accepting hydraulic fracturing wastewater until approximately May 2011. In April 2011, the Pennsylvania Department of Environmental Protection announced a request for Marcellus Shale natural gas drillers to voluntarily cease delivering their wastewater to the 15 POTWs. The state also promulgated regulations in November 2011 that established monthly average limits (500 milligrams per liter TDS, 250 milligrams per liter chloride, 10 milligrams per liter total barium, and 10 milligrams per liter total strontium) for new and expanded TDS discharges (PADEP, 2011). These limits do not apply to the 15 facilities identified in the voluntary request or other grandfathered treatment plants.

5.2.2.2. Commercial Waste Treatment Facility Processes

Commercial processes for treating hydraulic fracturing wastewater include crystallization (zero-liquid discharge), thermal distillation/evaporation, electrodialysis, reverse osmosis, ion exchange, and coagulation/flocculation followed by settling and/or filtration. Some treatment processes are better able to treat high-TDS waters, which is a common property of hydraulic fracturing wastewater. Thermal processes are energy-intensive, but are effective at treating high-TDS waters and may be able to treat hydraulic fracturing wastewater with zero liquid discharge, leaving only a residual salt. Electrodialysis and reverse osmosis may be feasible for treating lower-TDS wastewaters. These technologies are not able to treat high-TDS waters (>45,000 milligrams per liter) and may require pre-treatment (e.g., coagulation and filtration) to minimize membrane fouling.

Centralized waste treatment facilities can be used for pre-treatment prior to a POTW or, under an approved NPDES permit, can discharge directly to surface water (Figure 24). Commercial waste treatment processes will also result in some residual material that will require management and disposal.

5.2.2.3. Reuse

Gas producers are accelerating efforts to reuse and recycle hydraulic fracturing wastewater in some regions in order to decrease costs associated with procuring fresh water supplies, wastewater transportation, and offsite treatment and disposal. The EPA requested information on current wastewater management practices in the Marcellus Shale region from six oil and gas operators in May 2011.[62] Responses to the request for information indicated that reuse treatment technologies are similar, if not the same, to those used by WWTFs. Reuse technologies included direct reuse, onsite treatment (e.g., bag filtration, weir/settling tanks, third-party mobile treatment systems) and offsite treatment. Offsite treatment, in most instances, consisted of some form of stabilization, primary clarification, precipitation process, and secondary clarification and/or filtration. Specific details for offsite treatment methods were lacking as they are considered proprietary.

Innovation in coupling various treatment processes may help reduce wastewater volumes and fresh water consumed in hydraulic fracturing operations. A challenge facing reuse technology development is treating water onsite to an acceptable quality for reuse in subsequent hydraulic fracturing operations. Key water quality parameters to control include TDS, calcium, and hardness, all of which play a major role in scale formation in wells.

Recycling and reuse reduce the immediate need for treatment and disposal and water acquisition needs. There will likely be a need to treat and properly dispose of the final concentrated volumes of wastewater and residuals produced from treatment processes from a given area of operation, however.

5.2.3. Research Approach

The EPA is examining the fate and transport of chemicals through conventional POTW treatment processes and commercial chemical coagulation/settling processes. The objective of this work is to identify the partitioning of selected chemicals between solid and aqueous phases and to assess the biodegradation of organic constituents. In addition, microbial community health will be monitored in the reactors to identify the point where biological processes begin to fail. Contaminants that can pass through treatment processes and impact downstream PWS intakes will be identified.

[62] Documents received pursuant to the request for information are available at http://www.epa.gov/region3/marcellus_shale/.

Fate and Transport of Selected Contaminants in Wastewater Treatment Processes. The EPA will initially analyze the fate and transport of selected hydraulic fracturing–related contaminants in wastewater treatment processes, including conventional processes (primary clarifier, aeration basin, secondary clarifier), commercial processes (chemical precipitation/filtration and evaporation/distillation), and water reuse processes (pretreatment and filtration). The initial phase of this work will involve bench-scale fate and transport studies in a primary clarifier followed by 10 liter chemostat reactors seeded with microbial organisms from POTW aeration basins. In bench-scale work relevant to CWTs, similar fate and transport studies will be performed in chemical coagulation, settling, and filtration processes.

A list of contaminants (Table 42) for initial treatability studies have been identified and are based on the list of hydraulic fracturing-related chemicals identified for initial analytical method development (Table 45 in Section 5.4). Table 42 may change as future information on toxicity and occurrence is gathered. In addition to monitoring the fate of the contaminants listed in Table 42 in treatment settings, impacts on conventional wastewater treatment efficiency will be monitored by examining changes in chemical oxygen demand, biological oxygen demand, and levels of nitrate, ammonia, phosphorus, oxygen, TDS, and total organic carbon in the aeration basin.

Table 42. Chemicals identified for initial studies on the adequacy of treatment of hydraulic fracturing wastewaters by conventional publicly owned treatment works, commercial treatment systems, and water reuse systems. Chemicals were identified from the list of chemicals needing analytical method development (Table 45).

Target Chemical	CASRN	Target Chemical	CASRN
2,2-Dibromo-3-nitrilopropionamide	10222-01-2	Isopropanol*	67-63-0
Acrylamide	79-06-1	Magnesium*	7439-95-4
Arsenic*	7440-38-2	Manganese*	7439-96-5
Barium*	7440-39-3	Methanol*	67-56-1
Benzene*	71-43-2	Napthalene*	91-20-3
Benzyl chloride	100-44-7	Nonylphenol	68152-92-1
Boron*	7440-42-8	Nonylphenol ethoxylate	68412-54-4
Bromide*	24959-67-9	Octylphenol	1806-26-4
t-Butyl alcohol	75-65-0	Octylphenol ethoxylate	26636-32-8
Chromium*	7440-47-3	Potassium*	7440-09-7
Diethanolamine	111-42-2	Radium*	7440-14-4
Ethoxylated alcohols, C10–C14	66455-15-0	Sodium*	7440-23-5
Ethylbenzene*	100-41-4	Strontium*	7440-24-6
Ethylene glycol*	107-21-1	Thiourea	62-56-6
Formaldehyde	82115-62-6	Toluene*	108-88-3
Glutaraldehyde	111-30-8	Uranium	7440-61-1
Iron*	7439-89-6	Xylene*	1330-20-7

* Chemicals reported to be in flowback and produced water. See Table A-3 in Appendix A.

Characterization of Contaminants in Hydraulic Fracturing Wastewater Treatment Residuals. The EPA will examine the concentrations and chemical speciation of inorganic contaminants in treatment residuals. Residuals generated from the research described above will be analyzed for inorganic contaminant concentrations via EPA Method 3051A (Microwave Assisted Digestion) and inductively coupled argon plasma-optical emission spectrometry. Samples will also undergo analysis via X-ray absorption spectroscopy in order to assess oxidation state and chemical speciation of target contaminants. Organic contaminants will be analyzed via liquid or gas chromatography-mass spectrometry after accelerated solvent extraction of the solids.

5.2.4. Status and Preliminary Data

This research is currently in the planning stage.

5.2.5. Next Steps

Initial studies will focus on establishing thresholds of TDS tolerance in chemostat bioreactors. Once the basic salt thresholds have been established, selected chemicals from the 26R forms will be added to the salt stock solutions. Salt concentrations will be kept below the thresholds where effects on the biological processes were observed. Potentially biodegradable pollutants (e.g., organics) will be measured, and the EPA will attempt to identify breakdown products.

Constituents that are not biodegradable (e.g., elements and anions) will be tracked through the treatment process by analyzing system effluent using the appropriate EPA Methods and by analyzing residuals from the primary clarifier and the bioreactors. The results of these bench-scale studies will be applied to a pilot-scale system that would target compounds identified in bench-scale studies as being the most problematic due to their lack of degradation or removal in the treatment process.

For studies on commercial treatment systems using chemical addition/settling, the EPA plans to conduct jar tests that employ coagulants/flocculants at appropriate contact and settling times. The jar tests will be conducted at the bench-scale using actual hydraulic fracturing wastewater samples. The EPA will also attempt to mimic evaporative/distillation processes by using thermal treatment on actual hydraulic fracturing wastewater samples. Both the jar test samples and residuals from thermal treatment will be analyzed for the chemicals listed in Table 42. Elements in the residuals will also be characterized via X-ray diffraction and X-ray absorption microscopy.

5.2.6. Quality Assurance Summary

The initial QAPP, "Fate, Transport and Characterization of Contaminants in Hydraulic Fracturing Water in Wastewater Treatment Processes," was submitted on December 20, 2011, and approved in August 2012 (US EPA, 2012q).

Because project activities are still in an early stage, no TSA has been performed. A TSA will be performed once the project advances to the data collection stage.

As results are reported and raw data are provided from the laboratories, ADQs will be performed to verify that the quality requirements specified in the approved QAPP were met. Data will be qualified if necessary, based on these ADQs. The results of the ADQs will be reported with the summary of results in the final report.

5.3. Brominated Disinfection Byproduct Precursor Studies

The EPA is assessing the ability of hydraulic fracturing wastewater to contribute to DBP formation in drinking water treatment facilities, with a particular focus on the formation of brominated DBPs. This work will inform the following research question listed in Table 43 and is complemented by the analytical method development for DBPs (see Section 5.4).

Table 43. Secondary research questions potentially answered by studying brominated DBP formation from treated hydraulic fracturing wastewater.

Water Cycle Stage	Applicable Research Questions
Wastewater treatment and waste disposal	What are the potential impacts from surface water disposal of treated hydraulic fracturing wastewater on drinking water treatment facilities?

5.3.1. Introduction

Wastewaters from hydraulic fracturing processes typically contain high concentrations of TDS, including significant concentrations of chloride and bromide. These halogens are difficult to remove from wastewater; if discharged from treatment works, they can elevate chloride and bromide concentrations in drinking water sources. Upon chlorination at a drinking water treatment facility, chloride and bromide can react with naturally occurring organic matter (NOM) in the water and lead to the formation of DBPs. Because of their carcinogenicity and reproductive and developmental affects, the maximum contaminant levels (MCLs) of the DBPs bromate, chlorite, haloacetic acids, and total THMs in finished drinking water are regulated by the National Primary Drinking Water Regulations.[63] Table 44 summarizes the DBPs regulated and their corresponding MCLs.

Increased bromide concentrations in drinking water resources can lead to greater total THM concentrations on a mass basis and may make it difficult for some PWSs to meet the regulatory limits of total THM listing in Table 44 in finished drinking water. As a first step, this project is examining the formation of brominated THMs, including bromoform ($CHBr_3$), dibromochloromethane ($CHClBr_2$), and bromodichloromethane ($CHCl_2Br$), during drinking water treatment processes. The formation of haloacetic acids (HAAs) and nitrosamines during drinking water treatment processes is also being investigated.[64]

Reactions of brominated biocides used in hydraulic fracturing operations with typical drinking water disinfectants associated with chlorination or chloramination are also being explored.[65] Brominated biocides are often used in fracturing fluids to minimize biofilm growth. The objective of this work is to assess the contribution, if any, to brominated DBP formation and identify degradation pathways for brominated biocides.

[63] Authorized by the Safe Drinking Water Act.

[64] Nitrosamines are byproducts of drinking water disinfection, typically chloramination, and currently unregulated by the EPA. Data collected from the second Unregulated Contaminant Monitoring Rule indicate that nitrosamines are frequently being found in PWSs. Nitrosamines are potentially carcinogenic.

[65] Chlorination and chloramination are common disinfection processes used for drinking water.

Table 44. Disinfection byproducts regulated by the National Primary Drinking Water Regulations.

Disinfection Byproduct	Maximum Contaminant Level Goal* (milligrams per liter)	Maximum Contaminant Level† (milligrams per liter)
Total Trihalomethanes		
Bromodichloromethane	Zero	0.080 as an annual average (sum of the concentrations of all four trihalomethanes)
Bromoform	Zero	
Dibromochloromethane	0.060	
Chloroform	0.070	
Haloacetic Acids		
Dichloroacetic acid	Zero	0.060 as an annual average (sum of the concentrations of all five haloacetic acids)
Trichloroacetic acid	0.020	
Monochloroacetic acid	0.070	
Bromoacetic acid	Regulated with this group but has no MCL goal	
Dibromoacetic acid	Regulated with this group but has no MCL goal	
Bromate	Zero	0.010 as an annual average
Chlorite	0.80	1.0

* A maximum contaminant level goal is the non-enforceable concentration of a contaminant in drinking water below which there is no known or expected risk to health; they are established under the Safe Drinking Water Act.
† A maximum contaminant level (MCL) is an enforceable standard corresponding to the highest level of a contaminant that is allowed in drinking water. MCLs are set as close to MCL goals as feasible using the best available treatment technology and taking cost into consideration. MCLs are set under the Safe Drinking Water Act and apply only to water delivered by public water supplies (water supplies that serve 15 or more service connections or regularly serves an average of 25 or more people daily at least 60 days out of the year) (40 CFR 141.2).

It is important to note that hydraulic fracturing wastewater can potentially contain other contaminants in significant concentrations that could affect human health. The EPA identified the impacts of elevated bromide and chloride levels in surface water from hydraulic fracturing wastewater discharge as a priority for protection of public water supplies. This project will ultimately provide PWSs with information on the potential for brominated DBP formation in surface waters receiving discharges from WWTFs.

5.3.2. Research Approach

This research will (1) analyze and characterize hydraulic fracturing wastewater for presence of halides, (2) evaluate the effects of high TDS upon chlorination of surface water receiving discharges of treated hydraulic fracturing wastewater, and (3) examine the reactions of brominated biocides subjected to chlorination during drinking water treatment. Selected analytes for characterizing hydraulic fracturing wastewater include nitrosamines and the halide anions chloride, bromide, and iodide—ions that are the likeliest to form DBPs (Richardson, 2003), including THMs and HAAs.

Hydraulic fracturing wastewater samples have been obtained from several sources in Pennsylvania. The quantification of background concentrations of halides in the samples follows EPA Method 300.1 (rev. 1) and the modified version of the method using mass spectrometry detection for bromide and bromate (discussed in Section 5.4). The samples are also being analyzed for the presence of DBPs, including THMs (EPA Method 551.1), HAAs (EPA Method 552.1), and N-nitrosamines (EPA Method 521), as well as elemental composition, anion concentration, TDS, and total organic carbon.

Three treatments are being applied to high-TDS wastewater samples: (1) samples will be blended with deionized water at rates that mimic discharge into varying flow rates of receiving water in order to account for dilution effects; (2) samples will be blended with deionized water with NOM additions at concentration ranges typically found in surface waters; and (3) samples will be blended with actual surface water samples from rivers that receive treated hydraulic fracturing wastewater discharges. All samples will be subjected to formation potential experiments in the presence of typical drinking water disinfectants associated with chlorination or chloramination. Formation potential measures will be obtained separately for THMs, HAAs, and nitrosamines. Disinfection byproduct formation in surface water samples will be compared with DBP formation in deionized water as well as deionized water fortified with several NOM isolates from different water sources in order to examine the effects of different NOM on DBP formation.[66]

The brominated biocides 2,2-dibromo-3-nitropropionamide and 2-bromo-2-nitrol-1,3-propanediol, employed in hydraulic fracturing processes, are being subjected to chlorination conditions encountered during drinking water treatment. These experiments should provide insight on the potential formation of brominated THMs from brominated biocides. Effects of chlorination on the brominated biocides are also being monitored.

5.3.3. Status and Preliminary Data

Work has begun on total THM formation studies to identify potential problems with analysis (EPA Method 551.1) due to the high TDS levels typical in hydraulic fracturing wastewater. Wastewater influent and effluent samples were obtained from researchers involved in the source apportionment studies (Section 5.1) at two CWTs in Pennsylvania that are currently accepting hydraulic fracturing wastewater for treatment via chemical addition and settling. For this preliminary research, samples were diluted 1:100 with deionized water and equilibrated with sodium hypochlorite until a 2 milligrams per liter concentration of sodium hypochlorite was achieved (a typical disinfectant concentration for finished water from a PWS). The samples are being analyzed for pH, metals, TDS, total suspended solids, total organic content, and selected anions.

Efforts to identify and quantify the parent brominated biocides using liquid chromatography/mass spectrometry methods have been unsuccessful to date, possibly due to poor ionization of the brominated molecules. The biocide samples subject to chlorination have been prepared for analysis of THMs.

[66] The concentration, chemical composition, and reactivity of NOM varies by geographic location due to factors such as presence and type of vegetation, physical and chemical properties of the surrounding soil and water, biological activity, and human activity among many others.

5.3.4. Next Steps

When the preliminary work on potential analytical effects from high TDS on total THM recovery is complete, a series of experiments to assess the potential formation of DBPs during chlorination will be run on the following samples:

- Deionized water
- Deionized water, varying concentrations of NOM
- Deionized water plus TDS
- Deionized water plus TDS and NOM
- Hydraulic fracturing wastewater

This series of samples will allow THM formation comparisons between hydraulic fracturing wastewater samples and less complex matrices. Dilutions will be made on the samples based on effluent discharge rates for existing WWTFs and receiving water flow rates. The samples will undergo chlorination and be sub-sampled over time (e.g., 0 to 120 minutes). Chloride to bromide ratios will be set at 50:1, 100:1, and 150:1 to encompass the range of conditions that may be found in surface waters impacted by varying concentrations of chloride and bromide. The sub-samples will be analyzed for individual THMs and formation kinetics will be determined. The EPA anticipates obtaining data for the formation of HAAs and nitrosamines, though THMs are the priority at this time.

5.3.5. Quality Assurance Summary

The initial QAPP, "Formation of Disinfection By-Products from Hydraulic Fracturing Fluids," was submitted on June 28, 2011, and approved on October 5, 2011 (US EPA, 2011h). On June 7, 2012, an addendum was submitted and approved on June 28, 2012; this provided more details on modifications to EPA Method 300.1 for optimizing bromide/bromate recoveries in high-salt matrices. There are no deviations from existing QAPPs to report at this time.

A TSA was performed on March 15, 2012, for this research project. Five findings were observed, related to improved communication, project documentation, sample storage, and QA/QC checks. Recommended corrective actions were accepted to address the findings. Since the TSA was performed before data generation activities, no impact on future reported results is expected. It is anticipated that a second TSA will be performed as the project progresses.

As raw data are provided from the laboratories and results are reported, ADQs will be performed to verify that the quality requirements specified in the approved QAPP have been met. Data will be qualified if necessary based on these ADQs. Audits of data quality are scheduled for the first quarter of 2013 (none have been performed yet). The results of these ADQs will be reported with the summary of results in the final report.

5.4. *Analytical Method Development*

5.4.1. Relationship to the Study

Sample analysis is an integral part of the EPA's *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (US EPA, 2011e) and is clearly specified in research plans being carried out for the study's retrospective case studies, prospective case studies, and laboratory studies. The EPA requires robust analytical methods to accurately and precisely determine the composition of hydraulic fracturing-related chemicals in ground and surface water, flowback and produced water, and treated wastewater.

5.4.2. Project Introduction

Analytical methods enable accurate and precise measurement of the presence and quantities of different chemicals in various matrices. Since the quantification of the presence or absence of hydraulic fracturing-related chemicals will likely have substantial implications for the conclusions of the study, it is important that robust analytical methods exist for chemicals of interest.

In many cases, standard EPA methods that have been designed for a specific matrix or set of matrices can be used for this study. Standard EPA methods are peer-reviewed and officially promulgated methods that are used under different EPA regulatory programs. For example, EPA Method 551.1 is being used to detect THMs as part of the Br-DBP research project (see Section 5.3) and EPA Method 8015D is being used to detect diesel range organics in ground and surface water samples collected as part of the retrospective case studies (see Chapter 7).

In other cases, standard EPA methods are nonexistent for a chemical of interest. In these situations, methods published in the peer-reviewed literature or developed by consensus standard organizations (e.g., the American Society for Testing and Materials, or ASTM) are used. However, these methods are rarely developed for or tested within matrices associated with the hydraulic fracturing process. In rare, but existing cases, where no documented methods exist, researchers generally develop their own methods for determining the concentrations of certain chemicals of interest. For these latter two situations, the analytical methods chosen must undergo rigorous testing, verification, and potential validation to ensure that the data generated they generate are of known and high quality. The EPA has identified selected chemicals found in hydraulic fracturing fluids and wastewater for the development and verification of analytical methods.

5.4.3. Research Approach

5.4.3.1. Chemical Selection

Hydraulic fracturing-related chemicals include chemicals used in the injected fracturing fluid, chemicals found in flowback and produced water, and chemicals resulting from the treatment of hydraulic fracturing wastewater (e.g., chlorination or bromination at wastewater treatment facilities). Some of these chemicals are present due to the mobilization of naturally occurring chemicals within the geologic formations or through the degradation or reaction of the injected chemicals in the different environments (i.e., subsurface, surface and wastewater). The EPA has identified over 1,000 chemicals that are reported to be used in fracturing fluids or found in hydraulic fracturing wastewaters (see Appendix A); these range from the inert and innocuous, such as sand and water, to reactive and toxic chemicals, like alkylphenols and radionuclides.

To help choose chemicals for analytical method testing, a group of EPA researchers and analytical laboratory chemists discussed the factors most important to their research needs and to the overall study. The following criteria were developed to identify a subset of the chemicals listed in Appendix A for initial analytical method testing activities:

- Frequency of occurrence[67] in hydraulic fracturing fluids and wastewater
- Toxicity[68]
- Mobility in the environment (expected fate and transport)
- Availability of instrumentation/detection systems for the chemical

Table 45 lists the chemicals selected for analytical method testing and development. It includes 14 different classes of chemicals, 51 specifically identified elements or compounds, six groups of compounds (e.g., ethoxylated alcohols and light petroleum distillates), and two related physical properties (gross α and gross β analyses associated with radionuclides). The EPA will continually review Table 45 and add new chemicals as needed.

[67] Occurrence information was gathered from the US House of Representatives report *Chemicals Used in Hydraulic Fracturing* (2011) (USHR, 2011)and Colborn et al. (2011). Chemicals with high frequencies were considered for inclusion. However, some high-frequency chemicals were ultimately not included in the EPA's priority list of chemicals of interest. For example, while silica or silicon dioxide is often near the top of lists in terms of frequency of occurrence, this likely refers to the sand that is used as a proppant during the hydraulic fracturing process. Additionally, certain chemicals, such as hydrogen chloride or sulfuric acid, no longer exist as the initial compounds once dissolved in water and often react with other compounds. As a result, these chemicals, and others, were not added to the list.

[68] Colborn et al. (2011) provided toxicity information compiled from MSDS from industry and government agencies and compared the chemicals in their list with toxic chemical databases, such as TOXNET and the Hazardous Substances Database.

Table 45. Chemicals identified for analytical method testing activities. Selection criteria for the chemicals included, but were not limited to, frequency of occurrence in fracturing fluids and wastewater, toxicity, environmental mobility, and availability of detection systems for the chemical.

Chemical Class	Chemical Name(s)	CASRN	Purpose in Hydraulic Fracturing	Reason Selected
Alcohols	Propargyl alcohol	107-19-7	Corrosion inhibitor	Toxicity, frequency of use
	Methanol	67-56-1		
	Isopropanol	67-63-0		
	t-Butyl alcohol	75-65-0	Byproduct of t-butyl hydroperoxide	
Aldehydes	Glutaraldehyde	111-30-8	Biocide	Toxicity, frequency of use
	Formaldehyde	50-00-0	Biocide	
Alkylphenols	Octylphenol	27193-28-8	Surfactant	Toxicity, frequency of use
	Nonylphenol	84852-15-3		
Alkylphenol ethoxylates	Octylphenol ethoxylate	9036-19-5	Surfactant	Frequency of use
	Nonylphenol ethoxylate	26027-38-3		
Amides	Thiourea	62-56-6	Corrosion inhibitor	Toxicity
	Acrylamide	79-06-1	Friction reducer	Toxicity, frequency of use, requested by EPA researchers
	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	Biocide	
Amines (alcohol)	Diethanolamine	111-42-2	Foaming agent	Frequency of use
Aromatic hydrocarbons	BTEX, naphthalene, benzyl chloride, light petroleum hydrocarbons		Gelling agents, solvents	Toxicity, frequency of use, requested by EPA researchers
Carbohydrates	Polysaccharides		Byproduct	Requested by EPA researchers
Disinfection byproducts	Trihalomethanes, haloacetic acids, N-nitrosamines*		Byproduct	Toxicity
Ethoxylated alcohols	Ethoxylated alcohols, C8–10 and C12–18	68954-94-9	Surfactant	Frequency of use

Table continued on next page

Table continued from previous page

Chemical Class	Chemical Name(s)	CASRN	Purpose in Hydraulic Fracturing	Reason Selected
Glycols	Ethylene glycol	107-21-1	Crosslinker, breaker, scale inhibitor	Frequency of use
	Diethylene glycol	111-46-6		
	Triethylene glycol	112-27-6		
	Tetraethylene glycol	112-60-7		
	2-Methoxyethanol†	109-86-4	Foaming agent	
	2-Butoxyethanol†	111-76-2		
Halogens	Chloride	16887-00-6	Brine carrier fluid, breaker	Frequency of use
Inorganics	Barium	7440-39-3	Mobilized during hydraulic fracturing	Toxicity, frequency of use of potassium and sodium salts, mobilization of naturally occurring ions
	Strontium	7440-24-6	Mobilized during hydraulic fracturing	
	Boron	7440-42-8	Crosslinker	
	Sodium	7440-23-5	Brine carrier fluid, breaker	
	Potassium	7440-09-7	Brine carrier fluid	
Radionuclides	Gross α		Mobilized during hydraulic fracturing	Toxicity, mobilization of naturally occurring ions
	Gross β			
	Radium	13982-63-3		
	Uranium	7440-61-1		
	Thorium	7440-29-1		

* See Section 5.3.
† These compounds are chemically similar to glycols and are analyzed using the same methods.

5.4.3.2. Analytical Method Testing and Development

Method Development. The EPA's process for analytical method development is shown in Figure 26. In the first step, an existing base method is identified for the specific chemical(s) of interest in a given matrix. Base methods may include promulgated, standard methods or, if no standard methods are available, methods existing in peer-reviewed literature or developed through a consensus standard organization.

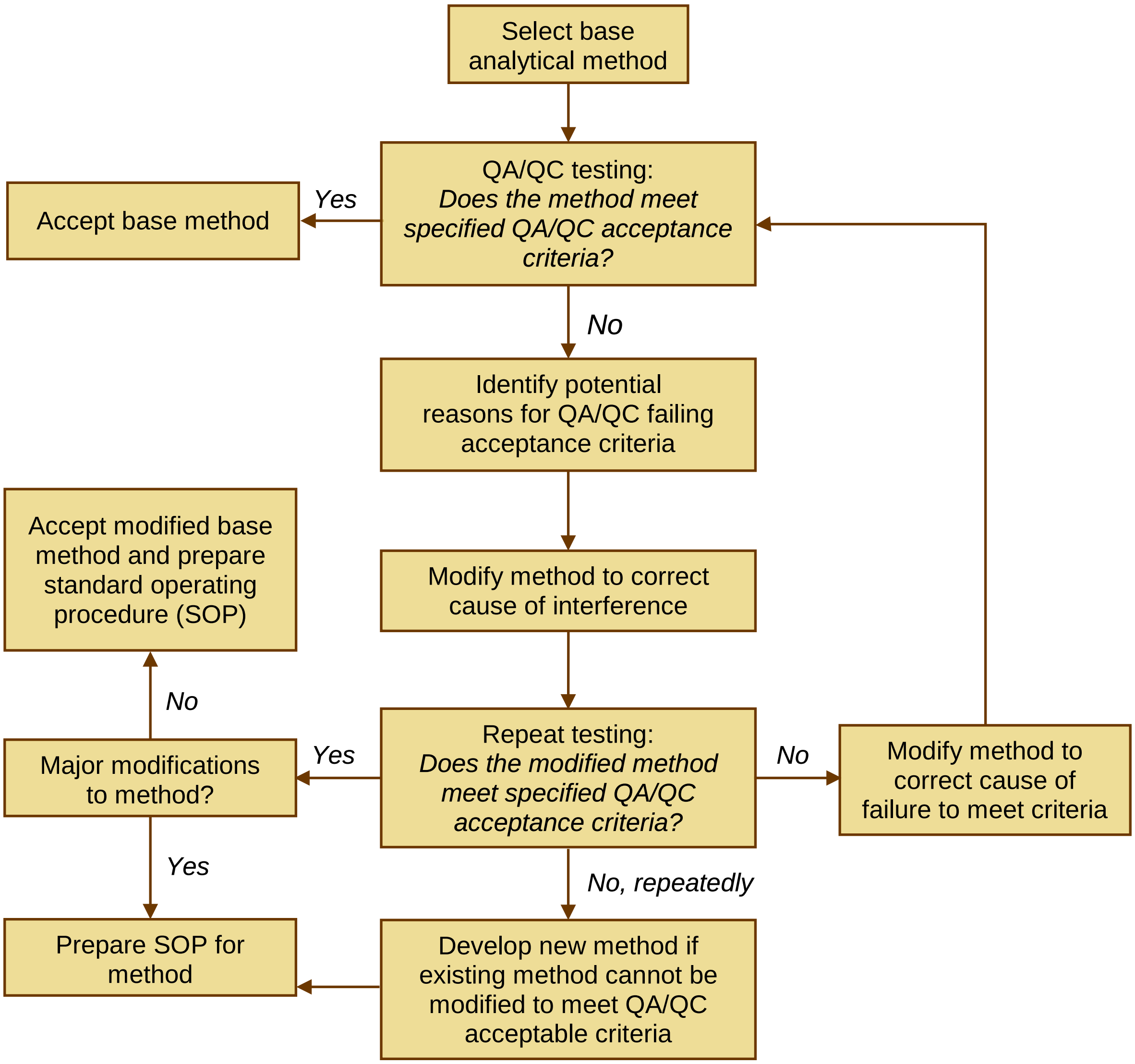

Figure 26. Flow diagram of the EPA's process leading to the development of modified or new analytical methods.

Analytical methods may exist for specific chemicals or for a general class of chemicals (e.g., alcohols). Table 46 lists the base methods identified for the 14 chemical classes shown in Table 45.

Table 46. Existing standard methods for analysis of selected hydraulic fracturing-related chemicals listed in Table 45. The EPA will analyze samples using existing methods to determine if the procedure meets the quality assurance criteria for the current study.

Chemical Class	Standard Method*
Alcohols	SW-846 Methods 5030 and 8260C
Aldehydes	SW-846 Method 8315
Alkylphenols	No standard method
Alkylphenol ethoxylates	No standard method
Amides	SW-846 Methods 8032A
Amines (alcohols)	No standard method
Aromatic hydrocarbons	SW-846 Methods 5030 and 8260C
Carbohydrates	No standard method
Disinfection byproducts	DWA Methods 521, 551, and 552
Ethoxylated alcohols	ASTM D7485-09
Glycols	Region 3 Draft Standard Operating Procedure
Halogens	SW-846 Method 9056A
Inorganic elements	SW-846 Methods 3015A and 6020A
Radionuclides	SW-846 Method 9310

* DWA methods can be found at http://water.epa.gov/scitech/methods/cwa/index.cfm. SW-846 Methods can be found at http://www.epa.gov/epawaste/hazard/testmethods/sw846/online/index.htm.

Once a candidate base method is selected,[69] an initial QA/QC round of testing is conducted. Testing occurs first with spiked laboratory water samples to familiarize the analyst with the method procedure, eliminate any potential matrix interferences, and determine various QA/QC control parameters, such as sensitivity, bias, precision, spike recovery, and analytical carry-over potential (sample cross-contamination). The results from the initial QA/QC testing are examined to determine if they meet the acceptance criteria specified in the QAPP (US EPA, 2011g) and thus are sufficient to meet the needs of the research study. Some of the key QA/QC samples examined include:

- Standard and certified reference materials (where available) for bias
- Matrix and surrogate spikes for bias (when reference materials are not available) and matrix interferences
- Replicates for precision
- Blanks for analytical carry-over

If an acceptance criterion for any of the QA/QC samples is not met, the sample is typically re-run to ensure that the result is not a random event. If an acceptance criterion is repeatedly not met, a

[69] Additional information on selecting a base method can be found in the QAPP, "Quality Assurance Project Plan for the Chemical Characterization of Select Constituents Relevant to Hydraulic Fracturing," found at http://www.epa.gov/hfstudy/qapps.html.

systematic problem is indicated, and method modification is undertaken to help reduce or eliminate the problem.

The method modification process can take many forms, depending on the specific circumstances, and may include changing sample preparation and cleanup techniques, solvents, filters, gas flow rates, temperature regimes, injector volumes, chromatographic columns, analytical detectors, etc. Once the method modification process is complete, the analysis is repeated as described above using spiked laboratory water samples. If the new QA/QC sample results meet the acceptance criterion, the method modification is deemed to have been successful for that matrix and an updated SOP is prepared. Additional testing in more complex water matrices will continue, if appropriate.

If testing and modification of the identified base method fails to accurately and precisely quantify the chemical of interest and/or fails to have the sensitivity required by the research program, the EPA may undertake new method development activities.

Method Verification. Method verification determines the robustness of successfully tested and modified analytical methods. This involves the preparation of multiple blind spiked samples (i.e., samples whose concentrations are only known to the sample preparer) by an independent chemist (i.e., one not associated with developing the method under testing and verification) and the submission of the samples to at least three other analytical laboratories participating in the verification process. Results from the method verification process can lead to either the acceptance of the method or re-evaluation and further testing of the method (US EPA, 1995).

Method Validation. The final possible step in analytical method testing and development is method validation. Method validation involves large, multi-laboratory, round robin studies and is generally conducted by the EPA program offices responsible for the publication and promulgation of standard EPA methods.

5.4.4. Status, Preliminary Data, and Next Steps

Method development, testing, and verification are being conducted according to the procedures outlined in two QAPPs: "Quality Assurance Project Plan for the Chemical Characterization of Select Constituents Relevant to Hydraulic Fracturing" (US EPA, 2011g) and "Quality Assurance Project Plan for the Inter-Laboratory Verification and Validation of Diethylene Glycol, Triethylene Glycol, Tetraethylene Glycol, 2-Butoxyethanol and 2-Methoxyethanol in Ground and Surface Waters by Liquid Chromatography/Tandem Mass Spectrometry" (US EPA, 2012r).

5.4.4.1. Glycols and Related Compounds

Glycols (diethylene glycol, triethylene glycol, and tetraethylene glycol) and the chemically related compounds 2-butoxyethanol and 2-methoxyethanol are frequently used in hydraulic fracturing fluids and not naturally found in ground water. Thus, they may serve as reliable indicators of contamination of ground water from hydraulic fracturing activities. EPA Method 8015b is the gas chromatography-flame ionization detector method typically used to analyze for glycols; however, the sensitivity is not sufficient for the low-level analysis required for this project. Therefore, the EPA's Region 3 Environmental Science Center developed a method for the determination and quantification of these compounds using liquid chromatography-tandem mass spectrometry. The method is based on ASTM D7731-11e1 and EPA SW-846 Method 8321. The EPA is currently verifying this method to determine its efficacy in identifying and quantifying these compounds in drinking water and other water matrices associated with the hydraulic fracturing process.

5.4.4.2. Acrylamide

Acrylamide is often used as a friction reducer in injected hydraulic fracturing fluids (GWPC, 2012b). EPA SW-846 Methods 8316 and 8032A are both suitable methods for the analysis of acrylamide. Method 8316 involves analysis by high-performance liquid chromatography with ultraviolet detector at 195 nanometers, with a detection level of 10 micrograms per liter. This short wavelength, however, is not very selective for acrylamide (i.e., interferences are likely), and the sensitivity is not adequate for measurements in water. Method 8032A involves the bromination of acrylamide, followed by gas chromatography-mass spectrometry analysis. This method is much more selective for acrylamide, and detection limits are much lower (0.03 micrograms per liter). However, in complex matrices (e.g., hydraulic fracturing wastewater), the accuracy and precision of acrylamide analysis may be limited by poor extraction efficiency and matrix interference.

To avoid reactions with other compounds present in environmental matrices and to lower the detection limit, the EPA is developing a new analytical method for the determination of acrylamide at very low levels in water containing a variety of additives. The method currently under development involves solid phase extraction with activated carbon followed by quantitation by liquid chromatography-tandem mass spectrometry using an ion exclusion column. The EPA has begun the multi-laboratory verification of the method.

5.4.4.3. Ethoxylated Alcohols

Surfactants are often added to hydraulic fracturing fluids to decrease liquid surface tension and improve fluid passage through pipes. Most of the surfactants used are alcohols or some derivative of an ethoxylated compound, typically ethoxylated alcohols. Many ethoxylated alcohols and ethoxylated alkylphenols biodegrade in the environment, but often the degradation byproducts are toxic (e.g., nonylphenol, a degradation product of nonylphenol ethoxylate, is an endocrine disrupting compound) (Talmage, 1994). No standard method currently exists for the determination of ethoxylated alcohols; therefore, the EPA is developing a quantitative method for ethoxylated alcohols. ASTM Method D 7458-09 and USGS Method Number O1433-01 were used as starting points for this method development effort; both of these methods involve solid-phase extraction followed by liquid chromatography-tandem mass spectrometry quantitation. These methods both allow the analysis of nonylphenol diethoxylate and alkylphenols, but there are currently no standard methods for the analysis of the full range of nonylphenol ethoxylate oligomers (EO_3–EO_{20}) or alcohol ethoxylate oligomers ($C_{12-15}EO_x$, where $x = 2$–20). This method SOP is being prepared and will be followed by method verification.

5.4.4.4. Disinfection Byproducts

Flowback and produced water can contain high levels of TDS, which may include bromide and chloride (US EPA, 2012d). In some cases, treatment of flowback and produced water occurs at WWTFs, which may be unable to effectively remove bromide and chloride from hydraulic fracturing wastewater before discharge. The presence of bromide ions in source waters undergoing chlorination disinfection may lead to the formation of brominated DBPs—including bromate, THMs, and HAAs—upon reaction with natural organic material (Richardson, 2003). Brominated DBPs are considerably more toxic than corresponding chlorinated DBPs (Plewa et al., 2004; Richardson et al., 2007) and have higher molecular weight. Therefore, on an equal molar basis, brominated DBPs will have a greater concentration by weight than chlorinated DBPs, hence leading to a greater likelihood of exceeding the total THM and HAA MCLs that are stipulated in weight concentrations (0.080 and 0.060 milligrams per liter, respectively). Accordingly, it is important to assess and quantify the effects of flowback and produced water on DBP generation (see Section 5.3).

Analytical methods for the measurement of bromide and bromate in elevated TDS matrices are currently being developed. EPA Method 300.1 is being modified to use a mass spectrometer rather that an electroconductivity detector, which is unable to detect bromide and bromate in the presence high anion concentrations (SO_4^{2-}, NO_2^-, NO_3^-, F^-, Cl^-). The mass spectrometer allows selected ion monitoring specifically for the two natural stable isotopes of bromine (^{79}Br and ^{81}Br), with minimal interference from other anions in the high-salt matrix. Interference of the bromide and bromate response in the mass spectrometer are being assessed by comparing instrument responses to solutions of bromide and bromate in deionized water with selected anions over a range of ratios typically encountered in hydraulic fracturing wastewater samples (US EPA, 2012d). Interference concentration thresholds are being established, and a suitable sample dilution method is being developed for the quantification of bromide and bromate in actual hydraulic fracturing wastewater samples. Method detection limits and lowest concentration minimum reporting levels are being calculated for bromide and bromate in high-salt matrices according to EPA protocols (US EPA, 2010h).

5.4.4.5. Radionuclides

Gross α and β analyses measure the radioactivity associated with gross α and gross β particles that are released during the natural decay of radioactive elements, such as uranium, thorium, and radium. Gross α and β analyses are typically used to screen hydraulic fracturing wastewater in order to assess gross levels of radioactivity. This information can be used to identify waters needing radionuclide-specific characterization. The TDS and organic content characteristic of hydraulic fracturing wastewater, however, interferes with currently accepted methods for gross α and β analyses. The QAPP for testing and developing gross α and β analytical methods is in development, and, after it is approved, work will begin.

5.4.4.6. Inorganic Chemicals

In addition to the potential mobilization of naturally occurring radioactive elements, hydraulic fracturing may also release other elements from the fractured shales, tight sands, and coalbeds, notably heavy metals such as barium and strontium. Inorganic compounds may also be added to hydraulic fracturing fluids to perform various functions (e.g., cross-linkers using borate salts, brine carrier fluids using potassium chloride, and pH-adjusting agents using sodium carbonates) (US EPA, 2011e). Due to the injection or release of naturally occurring metals in unknown quantities, it is essential that analytical methods for the determination of inorganic elements in waters associated with hydraulic fracturing be robust and free from interferences that may mask true concentrations.

The EPA SW-846 Method 6010, employing inductively coupled plasma-optical emission spectrometry, will be used as a base method for major elements while SW-846 Method 6020 based on inductively coupled plasma-mass spectrometry will be used as a base method for trace elements.[70] These methods will be tested and potentially modified for detection of major and trace elements in hydraulic fracturing wastewater.

5.4.5. Quality Assurance Summary

Three QAPPs have been prepared for the analytical method testing research program. The first QAPP, "Quality Assurance Project Plan for the Chemical Characterization of Select Constituents Relevant to Hydraulic Fracturing" (US EPA, 2011g), is the broad general QAPP for the methods development research project. The QAPP was approved on September 1, 2011. In order to maintain high QA standards and practices throughout the project, a surveillance audit was performed on November 15, 2011. The purpose of the surveillance audit was to examine the processes associated with the in-house extraction of ethoxylated alcohols. Three recommendations were identified and have been accepted.

The second QAPP, "Formation of Disinfection By-Products from Hydraulic Fracturing Fluid Constituents Quality Assurance Project Plan," (US EPA, 2011h), provides details on modifications to EPA Method 300.1 for optimizing bromide/bromate recoveries in high-salt matrices. The QAPP was approved on October 5, 2011, and the addendum for bromide/bromate analytic method development was approved on June 28, 2012. There are no deviations from existing QAPPs to report at this time. A surveillance audit was performed in March 2011 before the analytical method addendum (June 28, 2012); therefore, the analytical method development for bromide/bromate has not yet been audited.

The third QAPP, "Quality Assurance Project Plan for the Inter-Laboratory Verification and Validation of Diethylene Glycol, Triethylene Glycol, Tetraethylene Glycol, 2-Butoxyethanol and 2-Methoxyethanol in Ground and Surface Waters by Liquid Chromatography/Tandem Mass Spectrometry" (US EPA, 2012r), was prepared specifically for the verification of the EPA Region 3 SOP. The QAPP was approved on April 4, 2012. Since then, two surveillance audits and two internal TSAs have been performed, specifically looking at procedures related to glycol standard preparation and analysis. The two surveillance audits resulted in one case of potentially mislabeled samples during stock solution preparation. The potential mislabeling was already identified and documented by the researchers involved and corrective action taken. The designated EPA QA Manager found the methods in use satisfactory and further recommendations for improving the QA process were unnecessary. The internal TSAs also yielded no acts, errors, or omissions that would have a significant adverse impact on the quality of the final product.

[70] Major and trace elements are identified in the retrospective case study QAPPs found at http://www.epa.gov/hfstudy/qapps.html.

6. Toxicity Assessment

Throughout the hydraulic fracturing water lifecycle, routes exist through which fracturing fluids and/or naturally occurring substances could be introduced into drinking water resources. To support future risk assessments, the EPA is gathering existing data regarding toxicity and potential human health effects associated with the chemicals reported to be in fracturing fluids and found in wastewater. At this time, the EPA has not made any judgment about the extent of exposure to these chemicals when used in hydraulic fracturing fluids or found in hydraulic fracturing wastewater, or their potential impacts on drinking water resources.

6.1. Relationship to the Hydraulic Fracturing Study

The EPA is compiling existing information on chemical, physical, and toxicological properties of hydraulic fracturing-related chemicals, which include chemicals reported to be used in injected hydraulic fracturing fluids and chemicals detected in flowback and produced water. There are currently over 1,000 chemicals. This work focuses particularly on compiling and evaluating existing toxicological properties and will inform answers to the research questions listed in Table 47.

Table 47. Secondary research questions addressed by compiling existing information on hydraulic fracturing-related chemicals.

Water Cycle Stage	Applicable Research Questions
Chemical mixing	What are the chemical, physical, and toxicological properties of hydraulic fracturing chemical additives?
Flowback and produced water	What are the chemical, physical, and toxicological properties of hydraulic fracturing wastewater constituents?

6.2. Project Introduction

Given the potential for accidental human exposure due to spills, improper wastewater treatment, and potential seepage, it is important to understand the known and potential hazards posed by the diversity of chemicals needed during hydraulic fracturing. The US House of Representatives' Committee on Energy and Commerce Minority Staff released a report (2011) noting that more than 650 products (i.e., chemical mixtures) used in hydraulic fracturing contain 29 chemicals that are either known or possible human carcinogens or are currently regulated under the SDWA (see Table 11 in Section 3.1) (USHR, 2011). However, the report did not characterize the inherent chemical properties and potential toxicity of many of the reported compounds. The identification of inherent chemical properties will facilitate the development of models to predict environmental fate, transport, and the toxicological properties of chemicals. Through this level of understanding, scientists can design or identify more sustainable alternative chemicals that minimize or even avoid many fate, transport, and toxicity issues, while maintaining or improving commercial use.

The EPA must understand (1) potential hazards inherent to the chemicals being used in or released by hydraulic fracturing and returning to the surface in flowback and produced water, (2) dose-response characteristics, and (3) potential exposure levels in order to assess the potential impacts to human health from ingestion of drinking water that might contain the chemicals. The information from the toxicity assessment project provides a foundation for future risk assessments.

While the EPA currently does not have plans to conduct a formal risk assessment on this topic, the information may aid others who are investigating the risk of exposure.

6.3. Research Approach

Once the EPA identifies chemicals reported to be used in hydraulic fracturing fluids or found in flowback and produced water, physicochemical properties and chemical structures are assigned using various chemical software packages. Toxicological properties are then identified from authoritative sources or are estimated based on chemical structure.

Identification of Chemicals. The EPA, to date, has identified nine sources, listed in Table 48, that contain authoritative information on chemicals in used in hydraulic fracturing fluids or found in hydraulic fracturing wastewater. The sources have been used to compile two lists: chemicals reported to be used in hydraulic fracturing fluids and chemicals detected in hydraulic fracturing wastewater. Chemicals will be added to the two lists as new data become available.

Table 48. References used to develop a consolidated list of chemicals reportedly used in hydraulic fracturing fluids and/or found in flowback and produced water.

Description / Content	Reference
Chemicals reportedly used by 14 hydraulic fracturing service companies from 2005 to 2009	USHR, 2011
Products and chemicals used during natural gas operations with some potential health effects	Colborn et al., 2011
Chemicals used or proposed for use in hydraulic fracturing and chemicals found in flowback	NYSDEC, 2011
Chemicals reportedly used by nine hydraulic fracturing service companies from 2005 to 2010	US EPA, 2011b
MSDSs provided to the EPA during on-site visits	Material Safety Data Sheets
Table 4-1: Characteristics of undiluted chemicals found in hydraulic fracturing fluids (based on MSDSs)	US EPA, 2004b
Chemicals used in Pennsylvania for hydraulic fracturing activities (compiled from MSDSs)	PADEP, 2010
Chemical records entered in FracFocus for individual wells from January 1, 2011, through February 27, 2012	GWPC, 2012b
Chemicals detected in flowback from 19 hydraulically fractured shale gas wells in Pennsylvania and West Virginia	Hayes, 2009
Chemicals reportedly detected in flowback and produced water from 81 wells	US EPA, 2011k

While compiling the list of chemicals used in fracturing fluids, the EPA identified instances where various chemical names were reported for a single CASRN. Chemical name and structure annotation QC methods were applied to the reported chemicals in order to standardize the chemical names; this process is described in "Chemical Information Quality Review Procedures" for the Distributed Structure-Searchable Toxicity (DSSTox) Database Network.[71] The chemical QC methods included ensuring correct chemical names and CASRNs, and eliminating duplicates where appropriate. Chemical structures from the DSSTox database were assigned where possible.

Physicochemical Properties. Physicochemical properties of chemicals in the hydraulic fracturing fluid chemical list were generated from the two-dimensional (2-D) chemical structures from the EPA's DSSTox Database Network in structure-data file format. Properties were calculated using LeadScope chemoinformatic software (Leadscope Inc., 2012), Estimation Programs Interface Suite for Microsoft Windows (US EPA, 2012a), and QikProp (Schrodinger, 2012).[72] Both Leadscope and Qikprop software require input of desalted structures. Therefore, the structures were desalted, a process where salts and complexes are simplified to the neutral, uncomplexed form of the chemical, using Desalt Batch option in ChemFolder (ACD Labs, 2008). All Leadscope general chemical descriptors (Parent Molecular Weight, AlogP, Hydrogen Bond Acceptors, Hydrogen Bond Donors, Lipinski Score, Molecular Weight, Parent Atom Acount, Polar Surface Area, and Rotatable Bonds) were calculated by default. For EPISuite properties, both the desalted and non-desalted 2-D files were run using Batch Mode to calculate environmentally relevant, chemical property descriptors. The chemical descriptors in QikProp require 3-D chemical structures. For these calculations, the 2-D desalted chemical structures were converted to 3-D using the Rebuild3D function in the Molecular Operating Environment software (Chemical Computing Group). All computed physicochemical properties are added into the structure-data file prior to assigning toxicological properties.

Toxicological Properties. Known and predicted toxicity reference values are being combined into a single toxicity reference value resource for hydraulic fracturing-related chemicals. The EPA's list of hydraulic fracturing-related chemicals was cross-referenced against the following nine sources to obtain authoritative toxicity reference values:

- US EPA Integrated Risk Information System (IRIS)
- US EPA Provisional Peer-Reviewed Toxicity Value (PPRTV) database
- US EPA Health Effects Assessment Summary Tables
- Agency for Toxic Substances and Disease Registry Minimum Risk Levels
- State of California Toxicity Criteria Database
- State of Alabama Risk-Based Corrective Action document
- State of Florida Cleanup Target Levels
- State of Hawaii Maximum Contaminant List
- State of Texas Effects Screening Levels List

[71] For more information on DSSTox, see http://www.epa.gov/ncct/dsstox/ChemicalInfQAProcedures.html.

[72] The QikProp, EPI Suite, and LeadScope chemoinformatics programs calculate complementary properties with some overlap due to the process being performed in batch mode with all default properties included.

Authoritative toxicity reference values have been identified for over 100 of the more than 1,000 chemicals reported as being present in injected water or present in produced water. These include the benzene, toluene, ethylbenzene, and xylene (BTEX) chemicals, and over 70 others with toxicity reference values in the IRIS and PPRTV databases.

For the remaining chemicals that lack authoritative toxicity reference values, the structure-data file (generated for assigning physicochemical properties) can be used with the quantitative structure toxicity relationship software Toxicity Prediction by Komputer Assisted Technology, or TOPKAT (Accelrys Discovery Studio, 2012) to identify toxicity values. Rat chronic lowest observed adverse effect levels (LOAELs) were estimated using the LOAEL module for TOPKAT. The LOAEL module compares LOAEL values from open literature, National Cancer Institute/National Toxicology Program technical reports, and EPA databases to estimated rat oral LD_{50} values, and then compares the octanol-water partition coefficient from the chemical structure data file to the range in the training set.

The estimated LOAEL values will be compared to the authoritative toxicity reference values (for the chemicals with these authoritative values) to provide an estimate of how similar these values are. It is important to note that there may be significant deviation between the estimated LOAEL and the authoritative toxicity reference value for any given chemical due to the use of uncertainty factors in calculating the reference value, the fact that the reference values are not based on a rat chronic assay, and whether the reference values are calculated using the benchmark dose, a no observed adverse effect level, or a LOAEL. However, there is evidence that the estimated LOAEL is generally within 100 times the concentration of the actual rat chronic LOAEL (Rupp et al., 2010).

6.4. Status and Preliminary Data

Chemicals used in fracturing fluids or found in flowback and produced water, reported by the sources listed in Table 48, were consolidated and annotated, resulting in lists containing 1,027 unique chemical substances, of which 751 could be assigned a chemical structure and all but 5 assigned CASRNs. Physicochemical properties have been obtained for 318 of the 751 chemicals with structures. Physicochemical properties for the remainder of the chemicals with structures are currently being calculated. There were an additional 409 substances that were too poorly defined in the original lists to be unambiguously designated as unique substances, assigned CASRNs or chemical structures. The chemical lists are provided in Appendix A. The EPA has completed the first phase of development for the toxicity reference value database described above.

6.5. Next Steps

The EPA is currently identifying any additional state-based reference value data sources that can be useful; these additional sources, if any, will be brought into the database as they are identified.

6.6. Quality Assurance Summary

There are two QAPPs associated with this project. The first “Health and Toxicity Theme Hydraulic Fracturing Study Immediate Office National Center for Environmental Assessment,” was approved February 2012 and describes the development of the toxicity reference value master spreadsheet (US EPA, 2012k). The second QAPP, “Health and Toxicity (HT) Hydraulic Fracturing (HF) National Center for Computational Toxicology,” was approved February 2012 and describes the planning and quality processes for the generation of the chemical lists and the calculation of physicochemical properties for the chemicals for which chemical structures can be assigned (US EPA, 2012i).

7. Case Studies

7.1. Introduction to Case Studies

Case studies are widely used to conduct in-depth investigations of complex topics and provide a systematic framework for investigating relationships among relevant factors. In conjunction with other elements of the research program, they help determine whether hydraulic fracturing can impact drinking water resources and, if so, the extent and possible causes of any impacts. Case studies may also provide opportunities to assess the fate and transport of fluids and contaminants in different regions and geologic settings. Results from the case studies are expected to help answer the secondary research questions listed in Table 49.

Table 49. Secondary research questions addressed by conducting case studies.

Water Cycle Stage	Applicable Secondary Research Questions
Chemical mixing	• If spills occur, how might hydraulic fracturing chemical additives contaminate drinking water resources?
Well injection	• How effective are current well construction practices at containing gases and fluids before, during, and after hydraulic fracturing? • Can subsurface migration of fluids or gases to drinking water resources occur, and what local geologic or man-made features might allow this?
Flowback and produced water	• If spills occur, how might hydraulic fracturing wastewaters contaminate drinking water resources?

Two types of case studies are being conducted as part of this study. Retrospective case studies focus on investigating reported instances of drinking water resource contamination in areas where hydraulic fracturing events have already occurred. Prospective case studies involve sites where hydraulic fracturing will be implemented after the research begins, which allows sampling and characterization of the site before, during, and after drilling, injection of the fracturing fluid, flowback, and production. The EPA continues to work with industry partners to design and develop prospective case studies. Because prospective case studies remain in their early stages, the progress report focuses on the progress of retrospective case studies only.

To select the retrospective case study sites, the EPA invited stakeholders from across the country to participate in the identification of locations for potential case studies through informational public meetings and the submission of electronic or written comments. Following thousands of comments, over 40 locations were nominated for inclusion in the study.[73] These locations were prioritized and chosen based on a rigorous set of criteria, including proximity of population and drinking water supplies, evidence of impaired water quality, health and environmental concerns, and knowledge gaps that could be filled by a case study at each potential location. Sites were prioritized based on geographic and geologic diversity, population at risk, geologic and hydrologic features, characteristics of water resources, and land use (US EPA, 2011e). Five retrospective case study locations were ultimately chosen for inclusion in this study and are shown in Figure 27.

[73] A list of the sites submitted for consideration can be found in the Study Plan.

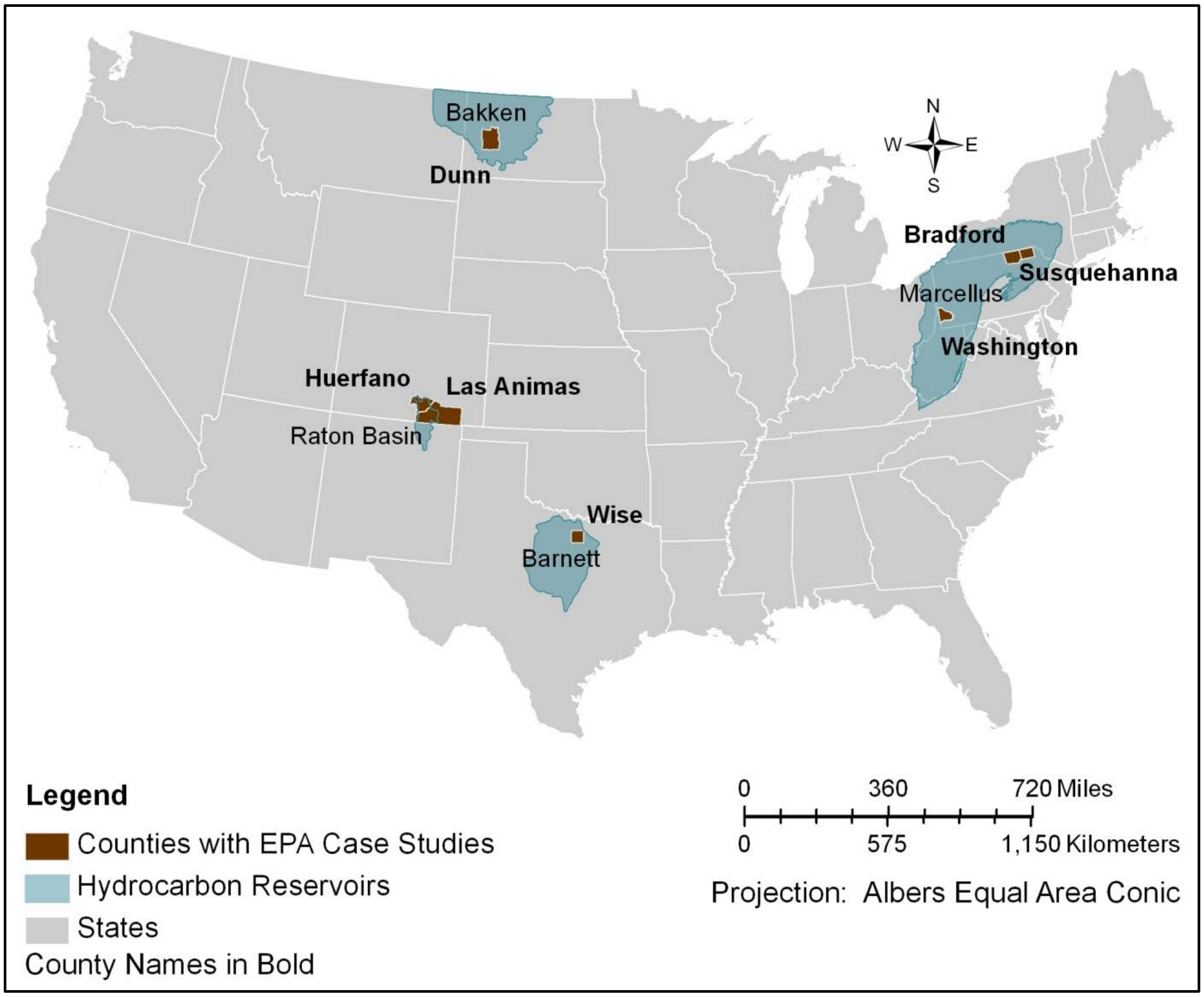

Figure 27. Locations of the five retrospective case studies chosen for inclusion in the EPA's Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The locations were nominated by stakeholders and selected based on criteria described in the text. (ESRI, 2010a, b; US EIA, 2011d, e)

7.1.1. General Research Approach

Although each retrospective case study differs in the geologic and hydrologic characteristics, as well as the hydraulic fracturing techniques used and the oil and gas exploration and production history of the area, the methods used to assess potential drinking water impacts are applicable to all of the study sites. By coordinating the case study methods and analyses, it will be possible to compare the results of each study. Table 50 describes the general research approach being used for the retrospective case studies.[74] The tiered scheme uses the results of earlier tiers to refine sampling activities in later tiers. This approach is both useful and appropriate when the impacts to drinking water resources and the potential sources of the impacts are unknown. For example, it allows the sampling to verify key findings and adjust to the improved understanding of the site.

[74] The Dunn County, North Dakota, retrospective case study does not use this tiered sampling plan because it is designed to examine the impacts of a well blowout during hydraulic fracturing. Since the potential source of contamination is known, the tiered sampling plan is not necessary.

Table 50. General approach for conducting retrospective case studies. The tiered approach uses the results of earlier tiers to refine sampling activities in later tiers.

Tier	Goal	Critical Path
1	Verify potential issue	• Evaluate existing data and information from operators, private citizens, state and local agencies, and tribes (if any) • Conduct site visits • Interview stakeholders and interested parties
2	Determine approach for detailed investigations	• Conduct initial sampling of water wells, taps, surface water, and soils • Identify potential evidence of drinking water contamination • Develop conceptual site model describing possible sources and pathways of the reported or potential contamination • Develop, calibrate, and test fate and transport model(s)
3	Conduct detailed investigations to detect and evaluate potential sources of contamination	• Conduct additional sampling of soils, aquifer, surface water, and wastewater pits/tanks (if present) • Conduct additional testing, including further water testing with new monitoring points, soil gas surveys, geophysical testing, well mechanical integrity testing, and stable isotope analyses • Refine conceptual site model and further test exposure scenarios • Refine fate and transport model(s) based on new data
4	Determine the source(s) of any impacts to drinking water resources	• Develop multiple lines of evidence to determine the source(s) of impacts to drinking water resources • Exclude possible sources and pathways of the reported contamination • Assess uncertainties associated with conclusions regarding the source(s) of impacts

Each retrospective case study has developed a QAPP that describes the detailed plan for the research at that location. The QAPP integrates the technical and quality aspects of the case study in order to provide a guide for obtaining the type and quality of environmental data required for the research. Before each new tier of sampling begins, the QAPPs are revised to account for any changes.

Ground water samples have been collected at all retrospective case study locations. The samples come from a variety of available sources, such as existing monitoring wells, domestic and municipal water wells, and springs. Surface water, if present, has also been sampled. During sample collection, the following water quality parameters were monitored and recorded:

- Temperature
- pH
- TDS
- Specific conductivity
- Alkalinity
- Turbidity
- Dissolved oxygen

- Oxidation/reduction potential
- Ferrous iron
- Hydrogen sulfide

Each water sample has been analyzed for a suite of chemicals; groups of analytes and examples of specific chemicals of interest are listed in Table 51. These chemicals include major anions, components of hydraulic fracturing fluids (i.e., glycols), and potentially mobilized natural occurring substances (i.e., metals);[75] these chemicals are thought to be present frequently in hydraulic fracturing fluids or wastewater. As indicated in Table 51, stable isotope analyses are also being conducted. Stable isotope compositions can be important indicators of what is naturally occurring in the environment being studied. If an element has multiple stable isotopes, one is usually the most common form in that environment. Due to different processes that may occur in or around the environment, other stable isotopes of the element may be found. The different isotopes can make it easier to determine the source of, or distinguish between, sources of contamination.

Table 51. Analyte groupings and examples of chemicals measured in water samples collected at the retrospective case study locations.

Analyte Groups	Examples
Anions	Bromide, chloride, sulfate
Carbon group	Dissolved organic carbon,* dissolved inorganic carbon†
Dissolved gases	Methane, ethane, propane
Extractable petroleum hydrocarbons	Gasoline range organics,§ diesel range organics‡
Glycols	Diethylene glycol, triethylene glycol, tetraethylene glycol
Isotopes	Isotopes of oxygen and hydrogen in water, carbon and hydrogen in methane, strontium
Low molecular weight acids	Formate, acetate, butyrate
Measures of radioactivity	Radium, gross α, gross β
Metals	Arsenic, manganese, iron
Semivolatile organic compounds	Benzoic acid; 1,2,4-trichlorobenzene; 4-nitrophenol
Surfactants	Octylphenol ethoxylate, nonylphenol
Volatile organic compounds	Benzene, toluene, styrene

* Dissolved organic carbon is a result of the decomposition of organic material in aquatic systems.
† Dissolved inorganic carbon is the sum of the carbonate species (e.g., carbonate, bicarbonate) dissolved in water.
§ Gasoline range organics include hydrocarbon molecules containing 5–12 carbon atoms.
‡ Diesel range organics include hydrocarbon molecules containing 15–18 carbon atoms.

The samples taken for the case studies were analyzed by the EPA Region 8 Laboratory and the EPA Robert S. Kerr Environmental Research Center. A laboratory TSA was conducted at the EPA Region 8 Laboratory on July 26, 2011; no findings were identified. In addition, a laboratory TSA was conducted for the onsite analytical support at the Robert S. Kerr Environmental Research Center on July 28, 2011, which included Shaw Environmental and the EPA General Parameter Lab; no findings

[75] A complete list of chemicals and corresponding analytical methods is available in the QAPPs for each case study. See http://www.epa.gov/hfstudy/qapps.html.

were identified. The laboratory TSAs were conducted on these laboratories during the first retrospective case study sampling event to identify any problems early and allow for corrective actions, if needed. Additional TSAs will be performed if determined to be necessary based on quality concerns.

This chapter includes progress reports for the following retrospective case studies:

7.2. Las Animas and Huerfano Counties, Colorado

7.2.1. Project Introduction

Las Animas and Huerfano Counties, Colorado, are located on the eastern edge of the Rocky Mountains and have a combined population of about 22,000 people and a population density of about 4 people per square mile (USCB, 2010c, d). As shown in Figure 28, the coal-bearing region of the Raton Basin occupies an area of 1,100 square miles within these two counties. The development of CBM resources in the Raton and Vermejo Formations within the Raton Basin has increased due to advances in hydraulic fracturing technology (Keighin, 1995; Watts, 2006b).

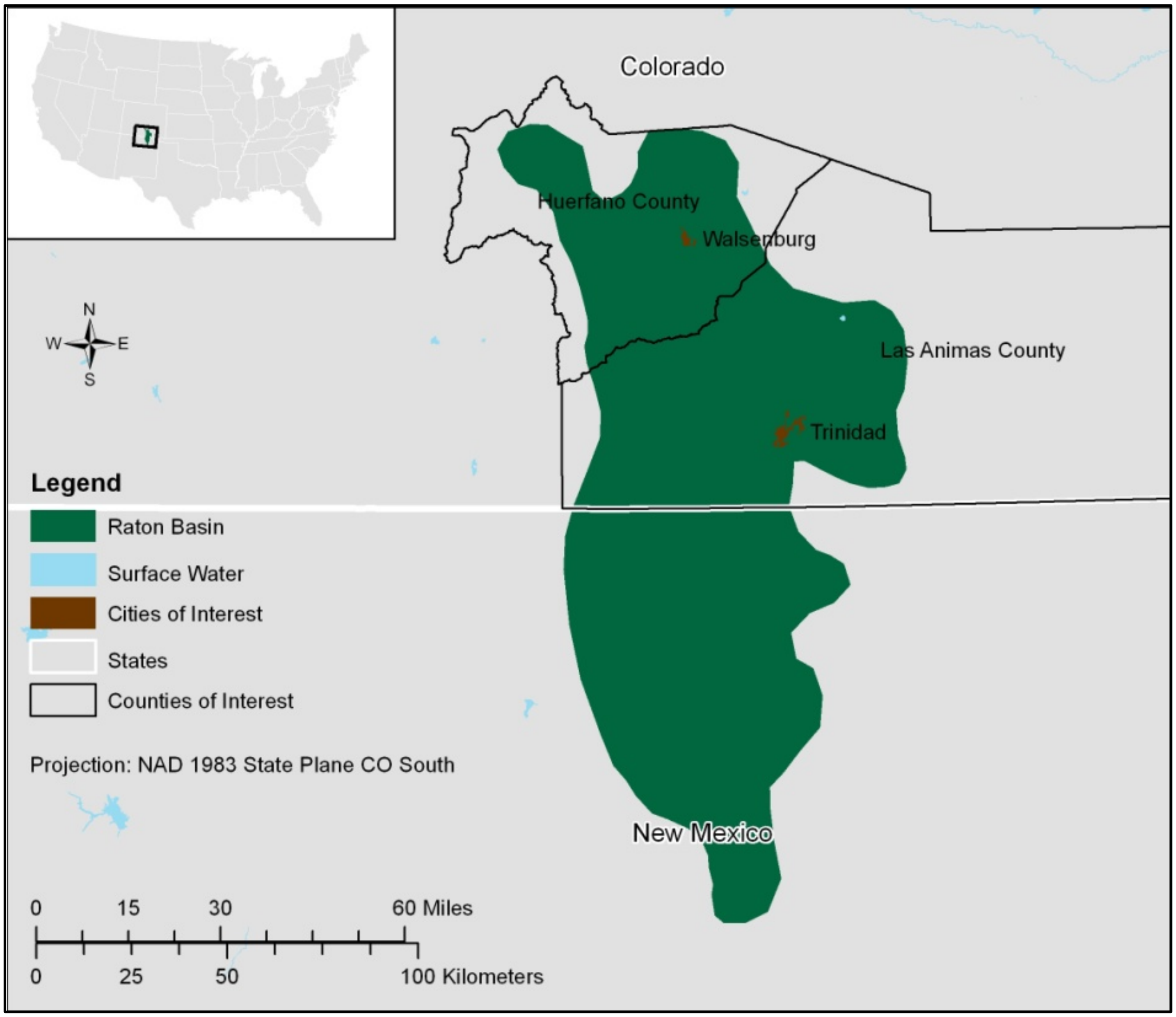

Figure 28. Extent of the Raton Basin in southeastern Colorado and northeastern New Mexico (ESRI, 2012; US EIA, 2011d; USCB, 2012a, b, c). The case study includes two locations: "North Fork Ranch," located northwest of the city of Trinidad in western Las Animas County, and "Little Creek," located southwest of the city of Walsenburg in Huerfano County.

Study site locations in Las Animas and Huerfano Counties were selected in response to ongoing complaints about changes in appearance, odor, and taste associated with drinking water in domestic wells. These sites include "North Fork Ranch," located northwest of the city of Trinidad in western Las Animas County, and "Little Creek," located southwest of the city of Walsenburg in Huerfano County. In some locations, point-of-use water treatment systems have been installed on properties to treat elevated methane and sulfide concentrations in well water. This case study focuses on the potential impacts of hydraulic fracturing on drinking water resources near these two study sites. Potential sources of ground water contamination under consideration include activities associated with natural sources, CBM extraction (such as leaking or abandoned pits), gas well completion and enhancement techniques, improperly plugged and abandoned wells, gas migration, and residential impacts.

7.2.2. Site Background

Geology. The Raton Basin is a north-south trending sedimentary and structural depression located along the eastern edge of the Rocky Mountains, between the Sangre de Cristo Mountains to the west and the Apishapa, Las Animas, and Sierra Grande arches on the east (Watts, 2006a). This chevron-shaped basin encompasses roughly 2,200 square miles of southeastern Colorado and northeastern New Mexico, extending from southern Colfax County, New Mexico, through Las Animas County, Colorado, and northward into Huerfano County, Colorado, as shown in Figure 28 (Tremain, 1980). It is the southernmost of the several major coal-bearing basins located along the eastern margin of the Rocky Mountains (Johnson and Finn, 2001). Within the Raton Basin, the Vermejo and Raton Formations contain CBM resources being extracted using hydraulic fracturing.

Las Animas and Huerfano Counties are underlain by sedimentary bedrock ranging in age from the late Cretaceous to the Eocene (see Appendix D for a geologic timeline). Igneous intrusions, dating to the Eocene, Miocene, and Pliocene epochs, occur throughout the area. The sedimentary sequence exposed within the Raton Basin was deposited in association with regression of the Cretaceous Interior Seaway, and the stratigraphy reflects deposition in fluvial systems and peat-forming swamps (Cooper et al., 2007; Flores, 1993). Numerous discontinuous and thin coalbeds are located in the Vermejo and Raton Formations, which lie directly above the Trinidad Sandstone. The upper Trinidad intertongues with, and is overlain by, the coal-bearing Vermejo Formation (Topper et al., 2011). No coal is found below this sandstone (Greg Lewicki & Associates, 2001).

Individual coalbeds in the Vermejo Formation consist of interbedded shales, sandstones, and coalbeds. The Vermejo Formation ranges in thickness from 150 feet in the southern part of the basin to 410 feet in the northern part (Greg Lewicki & Associates, 2001). This formation contains from 3 to 14 coalbeds over 14 inches thick throughout the entire basin, and total coal thickness typically ranges from 5 to 35 feet (US EPA, 2004b).

The Raton Formation overlies the Vermejo Formation. The Raton Formation ranges from 0 to 2,100 feet thick and is composed of a basal conglomerate, a middle coal-bearing zone, and an upper transitional zone (Johnson and Finn, 2001; US EPA, 2004b). Its middle coal-bearing zone is approximately 1,000 feet thick and consists of shales, sandstones, and coalbeds (Greg Lewicki & Associates, 2001). This zone also contains coal seams that have been mined extensively; total coal thickness ranges from 10 feet to more than 140 feet in this zone, with individual seams ranging in thickness from several inches to more than 10 feet (US EPA, 2004b). Sandstones are interbedded with coalbeds that are currently being developed for CBM, and the coalbeds are the likely source for gas found in the sandstones (Johnson and Finn, 2001).

Water Resources. Las Animas and Huerfano Counties are located in the Arkansas River Basin and are drained by the Purgatoire, Apishapa, and Cucharas Rivers. The coal-bearing region of the Raton Basin is predominantly drained by the Purgatoire and Apishapa Rivers; many stream segments of these rivers are currently on Colorado’s list of impaired waters (CDPHE, 2012). Annual precipitation in the Raton Basin is generally correlated to elevation, ranging from over 30 inches per year in the Spanish Peaks to less than 16 inches per year in eastern portions of the basin, which are at lower elevation. Much of the precipitation falls as winter snow in the mountains or as intense summer rain in the plains (Abbott, 1985; S.S. Papadopulos & Associates Inc, 2008). Ground water-based drinking water resources in Las Animas and Huerfano Counties reside in four bedrock aquifers: (1) the Dakota Sandstone and Purgatoire Formation; (2) the Raton Formation, Vermejo Formation, and Trinidad Sandstone; (3) the Cuchara-Poison Canyon Formation; and (4) volcanic rocks (Abbott et al., 1983). Sources of recharge to the aquifers include runoff from the Sangre de Cristo Mountains, precipitation infiltration, and infiltration from streams and lakes (Abbott et al., 1983; CDM and GBSM, 2004). The depth to ground water depends mostly on topographic position. In all areas but the southeast corner of the basin, water can be encountered at less than 200 feet below ground surface (CDM and GBSM, 2004). Regional ground water flow is generally from west to east, except where it is intercepted by valleys that cut into the rock (Watts, 2006b).

Within the hydrogeologic units of the Raton Basin, sandstone and conglomerate layers transmit most of the water; shale and coal layers generally retard flow. However, fracture networks in the shales and coal provide pathways which can transmit fluids or gas. Talus and alluvium may yield large quantities of water, but are limited in size, and discharges from these units fluctuate seasonally (Abbott et al., 1983). Aquifer tests in the Raton-Vermejo aquifers indicate hydraulic conductivities that range from 0 to 45 feet per day (Abbott et al., 1983).

Geologic formations have distinctive ground water chemistry. The Cuchara-Poison Canyon Formation is typically calcium-bicarbonate type with less than 500 milligrams per liter TDS content, while the Raton-Vermejo-Trindad aquifer is typically sodium-bicarbonate with TDS concentrations less than 1,500 milligrams per liter. Abbott et al. (1983) note that concentrations of boron, fluoride, iron, manganese, mercury, nitrate, selenium, and zinc are locally elevated due to a variety of geologic processes and human activities. High concentrations of fluoride occur in the Poison Canyon and Raton Formations, possibly due to the dissolution of detrital fluorite. Iron and manganese concentrations may be also elevated, particularly in areas where coals are present, due to the dissolution of pyrite and/or siderite contained in the coal seams. Nitrate enrichment often occurs in alluvial aquifers where fertilizers or animal wastes add nitrogen (Abbott et al., 1983).

Oil and Gas Exploration and Production. The Raton Basin contains substantial amounts of high- and medium-volatile bituminous coals, which extend from outcrops along the periphery of the region to depths of at least 3,000 feet in the deepest parts of the region (Jurich and Adams, 1984). Most of these coal resources are in the Vermejo and Raton Formations, which are the target formations for CBM production (Macartney, 2011; Tyler, 1995). These coalbeds have been extensively mined in the peripheral outcrop belt along major stream valleys, as well as in a few structural uplifts within the interior of the basin (Dolly and Meissner, 1977). Total coal resources estimated in the basin range from 1.5 billion to more than 17 billion short tons (Flores and Bader, 1999).

Production of natural gas in the Raton Basin began in the 1980s, but before 1995, there were no gas distribution lines out of the basin and fewer than 60 wells had been drilled (S.S. Papadopulos & Associates Inc, 2008). The Raton Basin is estimated to contain as much as 18.4 trillion cubic feet of CBM (Tyler, 1995). This area has recently seen a rapid expansion in the production of natural gas with recent advances in hydraulic fracturing technology. Between 1999 and 2004, annual production of Raton Basin CBM in Las Animas and Huerfano Counties increased from about 28 billion cubic feet to about 80 billion cubic feet, and the number of producing wells grew from 478 wells to 1,543 wells. During the same period, annual ground water withdrawals for CBM production increased from about 1.45 billion gallons to about 3.64 billion gallons (Watts, 2006b). Expansion of CBM wells has focused on the development of the Vermejo coals, since these coals are thicker and more continuous than those located in the Raton Formation (US EPA, 2004b).

7.2.3. Research Approach

A detailed description of the sampling methods and procedures for this case study can be found in the project's QAPP (US EPA, 2012o). Ground water and surface water sampling in this area is intended to provide a survey of water quality in Las Animas and Huerfano Counties. Data collection involves sampling water from domestic wells, surface water bodies (streams), monitoring wells,[76] and gas production wells at locations in both Las Animas and Huerfano Counties, as indicated in Figure 29. The locations of these sampling sites were chosen based on their proximity to production activity.

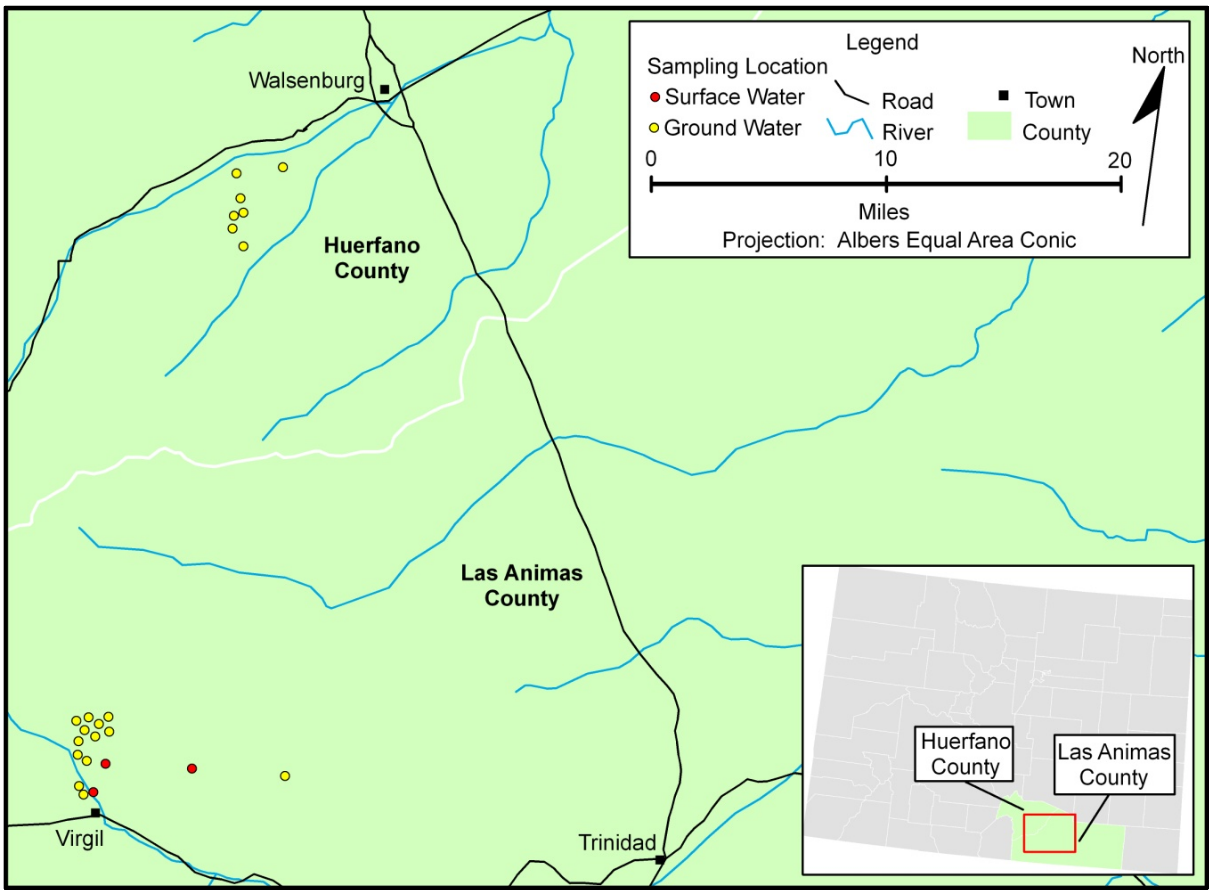

Figure 29. Locations of sampling sites in Las Animas and Huerfano Counties, Colorado. Water samples have been taken from domestic wells, surface water bodies (streams), monitoring wells, and gas production wells.

In addition to the analytes discussed in Section 7.1.1, the stable isotope compositions of carbon and hydrogen in methane, as well as the stable carbon isotope composition of dissolved inorganic carbon and the stable sulfur isotope composition of dissolved sulfate and dissolved sulfide, are

[76] Monitoring wells were installed by either Pioneer Natural Resources or Petroglyph Energy.

being analyzed as part of this case study. Microbial analyses are also being conducted on water samples collected at this case study location in order to better understand the biogeochemical cycling of carbon and sulfur in ground water. Together, these measurements support the objective of determining if ground water resources have been impacted, and, if so, whether they were impacted by hydraulic fracturing activities or other sources of contamination.

7.2.4. Status and Preliminary Data

As of August 2012, two sampling trips have been conducted: one in October 2011 and another in May 2012. During the October 2011 sampling trip, two production wells, five monitoring wells, 14 domestic water wells, and one surface water location were sampled. During the May 2012 sampling trip, two production wells, three monitoring wells, 12 domestic water wells, and three surface water locations were sampled. The locations of sampling sites are displayed in Figure 29.

7.2.5. Next Steps

Additional fieldwork to collect ground and surface water at each sampling location is tentatively scheduled for late 2012 and spring 2013. Sampling locations and analytes measured may be refined based on the results of the first two sets of samples. More focused investigations will also be conducted, if warranted, at locations where potential impacts associated with hydraulic fracturing may have occurred.

7.2.6. Quality Assurance Summary

The initial QAPP for this case study, "Hydraulic Fracturing Retrospective Case Study, Raton Basin, CO," was approved by the designated EPA QA Manager on September 20, 2011 (US EPA, 2012o). A revision to the QAPP was made before the second sampling event and was approved on April 30, 2012, to update project organization, update lab accreditation information, update sampling methodology, add sulfur isotope analyses, modify critical analytes, and change the analytical method for determining hydrogen and oxygen stable isotope ratios in water . There have been no significant deviations from the QAPP during any sampling event, and therefore no impact on data quality. A field TSA was conducted on October 4, 2011, during the first sample collection event; no findings were identified. See Section 7.1.1 for information related to the laboratory TSAs.

As results are reported and raw data are provided from the laboratories, ADQs are performed to verify that the quality requirements specified in the approved QAPP were met. Data will be qualified, if necessary, based on these ADQs. The results of these ADQs will be reported in the final report on this project.

7.3. Dunn County, North Dakota

7.3.1. Project Introduction

Dunn County, North Dakota, is a rural county with a population of 3,500 and an average population density of 1.8 people per square mile (USCB, 2010b); Killdeer is its largest city. This part of North Dakota is currently experiencing renewed natural gas exploration and a boom in oil production from the Bakken Shale, which extends domestically from western North Dakota to parts of northeastern Montana (Figure 30). The area's increased oil and gas exploration has relied greatly upon both horizontal drilling and hydraulic fracturing technologies.

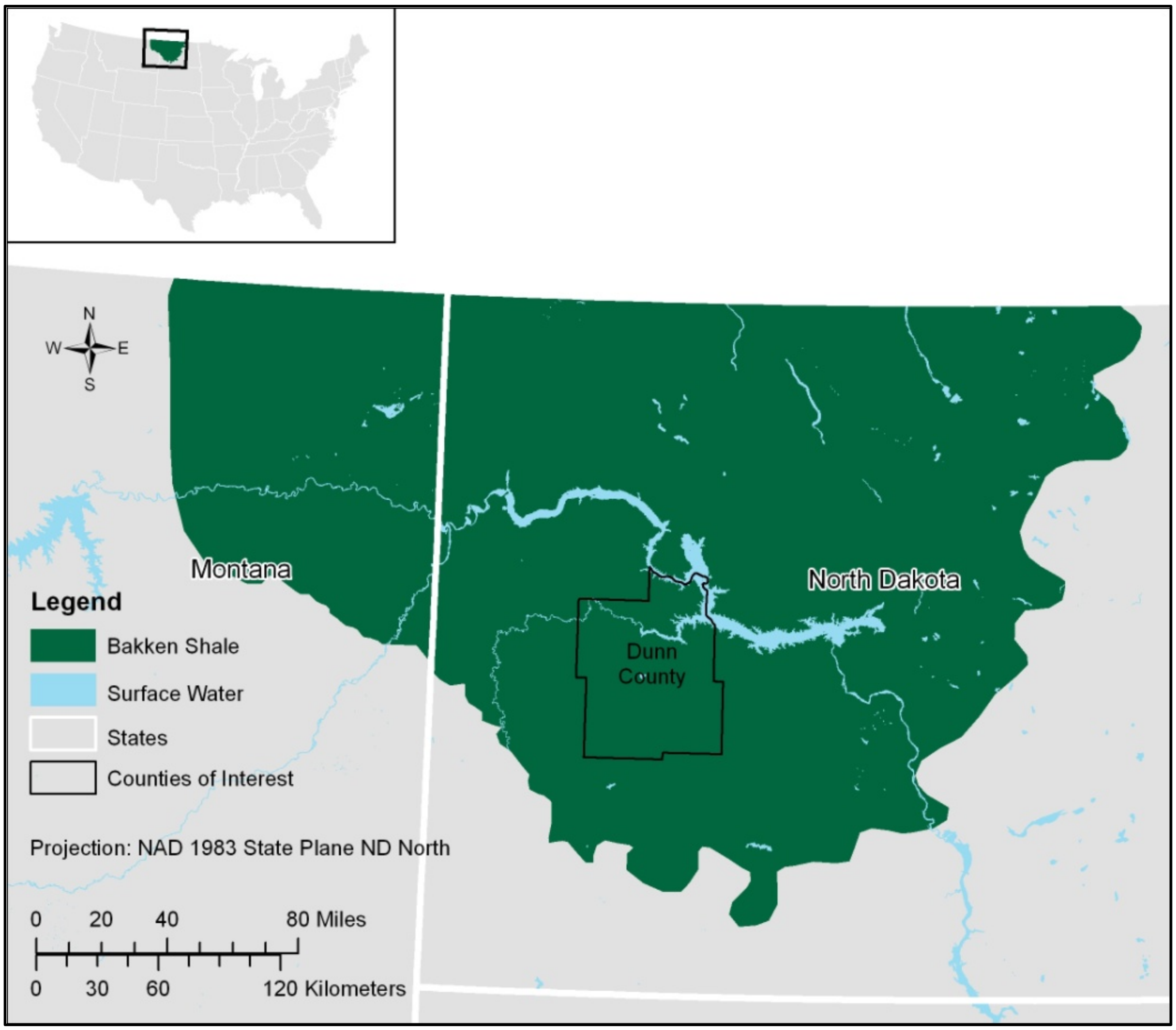

Figure 30. Extent of the Bakken Shale in North Dakota and Montana (US EIA, 2011d; USCB, 2012a, c). The case study focuses on a well blowout that occurred in Dunn County, North Dakota, in September 2010.

The EPA's case study site in Killdeer, North Dakota, was chosen at the request of the state to specifically examine any water resource impacts from a well blowout in September 2010 that resulted in an uncontrolled release of hydraulic fracturing fluids and formation fluids. The Killdeer Aquifer, the main source of drinking water for the city of Killdeer, underlies the study site. The blowout occurred at the Franchuk 44-20 SWH well, which is just outside the Killdeer municipal water supply well's 2.5 mile wellhead protection zone.

The uncontrolled blowout occurred on September 1, 2010, during the fifth stage of a hydraulic fracturing treatment of the Franchuk 44-20 SWH well. The intermediate well casing burst because of a 8,390 pounds per square inch pressure spike that released the pop-off relief valve. Hydraulic fracturing fluids and formation fluids began flowing from the ground around the well at several points and then flowed toward the northeast corner of the well pad, where they were contained by a 2 foot berm. During that day, 47,544 gallons of fluids were removed from the site. The following day, 88,000 gallons of fluids were removed from the site, and 15,120 gallons of mud were circulated into the well to kill it. Three monitoring wells were installed, but not sampled. Two down-gradient homeowner wells, an up-gradient homeowner well, and two municipal water wells were sampled on September 2. Three cement plugs were installed beginning at 9,000 feet in the wellbore, and 105,252 gallons of fluid were removed from the site. A bridge plug was set at 9,969 feet on September 6. From September 30 to October 15, 2,000 tons of contaminated soil were removed and disposed of (Jacob, 2011). Since the blowout, the State of North Dakota has overseen site cleanup and has required the well's operator to conduct ground water monitoring on a quarterly basis. In November 2010, the state asked the EPA to consider this site as part of this study, and the EPA agreed to do so.

7.3.2. Site Background

Geology. Dunn County is located in west-central North Dakota and is underlain by the sedimentary rocks of the Williston Basin. Although Dunn County marks the southern extent of glaciations in North Dakota, most of the glacial deposits have been eroded and the surface sediments are characterized by post-glacial, channel-fill deposits (Murphy, 2001). As described in Nordeng (2010), the Bakken formation is primarily composed of shale and dolomite, with some sandstone and siltstone. The Bakken Shale is of Late Devionian-Early Mississippian age (Appendix D) and is an organic-rich marine shale. It has no surface outcrop and is constrained by the Madison Formation above and the Wabamum, Big Valley, and Torquary Formations below (Murphy, 2001; Nordeng, 2010). The depths to the Bakken Shale range from 9,500 to 10,500 feet and its thickness ranges from very thin up to 140 feet (Carlson, 1985; Murphy, 2001).

Water Resources. Dunn County is a semi-arid region. Surface water in Dunn County is in the Missouri River Basin and includes the Little Missouri River to the northwest of the county and Lake Sakakawea to the northeast. These water resources supply water for domestic use, irrigation, industrial water, and hydraulic fracturing.

One of the major sources of drinking water in Killdeer is the Killdeer Aquifer: a glacial outwash aquifer, composed of fine to medium sand with course gravel near its base. It is shallow, with a maximum thickness of 233 feet. The aquifer is generally overlain by clay and silt soils (Klausing, 1979). Yields from the Killdeer Aquifer are high, ranging from 50 to 1,000 gallons per minute (Klausing, 1979). The major water types in the Killdeer Aquifer are sodium bicarbonate and sodium sulfate. Table 52 shows background water quality data for the Killdeer Aquifer, compiled by Klausing (1979).

Table 52. Background water quality data for the Killdeer Aquifer in North Dakota (Klausing, 1979). The range of boron, chloride, and iron in some samples was below the detection limit (BDL).

Parameter	Concentration Range (milligrams per liter)	Mean Concentration (milligrams per liter)
Bicarbonate	374–1,250	713
Boron	BDL–3.70	0.53
Chloride	BDL–25	4.5
Fluoride	0.1–2	0.66
Iron	BDL–5.50	1.03
Nitrate	0.3–6.7	1.2
Sodium	50–1,350	413
Sulfate	333–3,000	626
TDS	234–5,030	1,531

Oil and Gas Exploration and Production. Although it was known to contain large volumes of oil as early as the 1950s, difficulties in extracting the oil from the Bakken Shale kept production rates low (NDIC, 2012a). Hydraulic fracturing and horizontal drilling technologies have created greater access to the Bakken Shale oil reserves. In January 2003, Dunn County had 99 wells, producing approximately 86,000 barrels of oil (NDIC, 2003). By July 2012, the county had 854 wells, producing approximately 3.2 million barrels of oil (NDIC, 2012b).

7.3.3. Research Approach

A detailed description of this case study's sampling methods and procedures can be found in the QAPP (US EPA, 2011i). The primary objective of this case study is to assess the impacts of the Franchuk 44-20 SWH well blowout that occurred on September 1, 2010. Unlike the EPA's other four retrospective case studies, the Killdeer case study does not use a tiered approach because the potential source of contamination is known. Ground water sampling includes domestic, municipal, water supply, and monitoring wells.[77] Figure 31 shows the sampling locations in Dunn County, North Dakota.

[77] Terracon Consultants was contracted by the well operator, Denbury Resources, for the installation of monitoring wells.

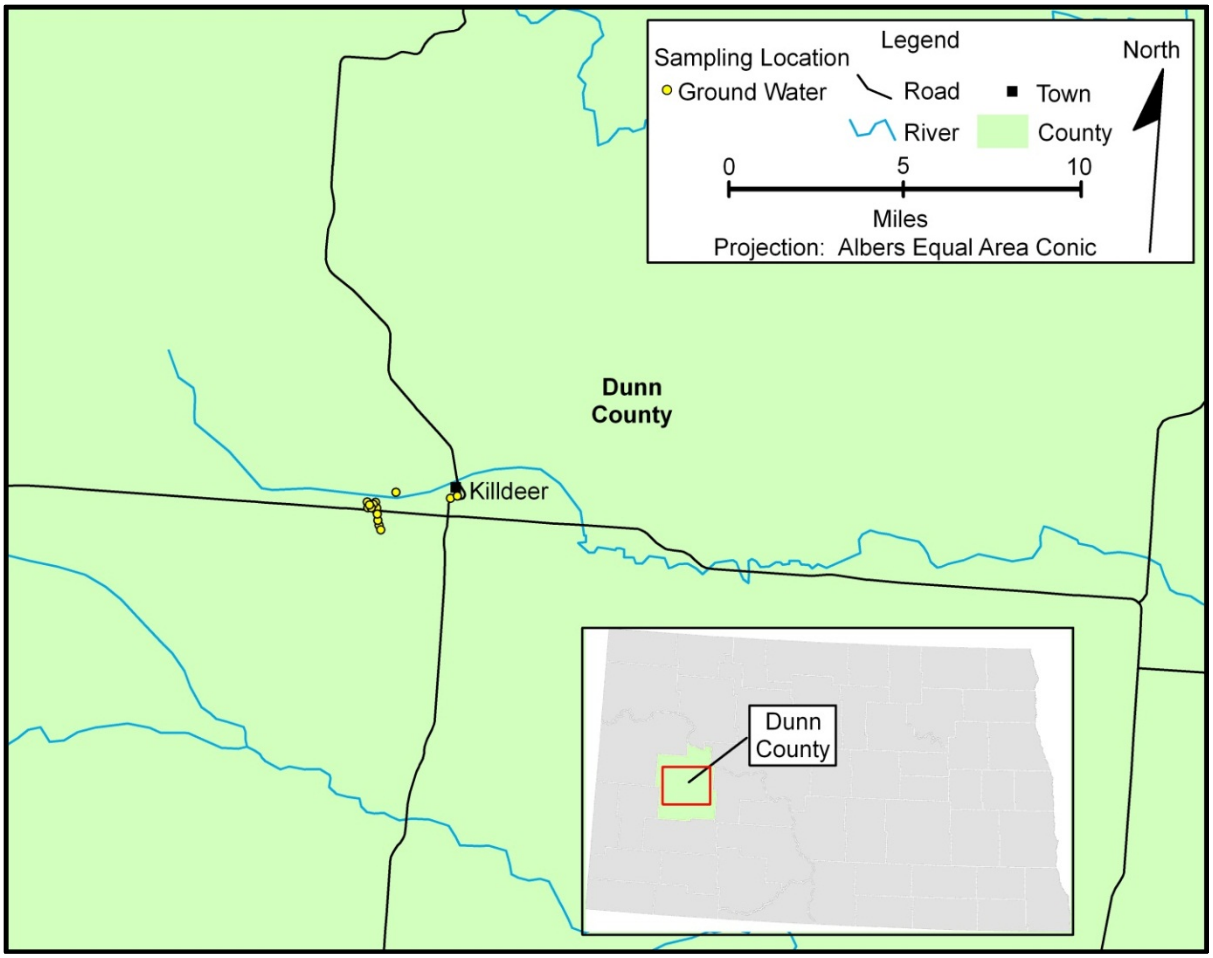

Figure 31. Location of sampling sites in Dunn County, North Dakota.

Domestic, municipal, and supply wells are being sampled at a tap as close to the wellhead as possible, before any treatment has occurred. Monitoring wells have been installed and have dedicated bladder pumps for sampling and purging operations. Water samples collected at these locations are being analyzed for the chemicals listed in Section 7.1.1 as well as the chemicals listed in the QAPP (US EPA, 2011i). The data collected as part of this case study will be compared to existing background data as part of the initial screening phase (Tier 2 in Table 50) to determine if any contamination has occurred in the study location.

7.3.4. Status and Preliminary Data

Two rounds of sampling were conducted in Killdeer in July and October 2011. Samples were collected at 10 monitoring wells, three domestic water wells, two water supply wells, and one municipal water well. The locations of sampling sites are displayed in Figure 31.

7.3.5. Next Steps

At least one more round of sampling is planned to verify data collected from the first two rounds of sampling. Additional sampling locations or analytes may be included in future rounds as analytical data are evaluated and additional pertinent information becomes available.

7.3.6. Quality Assurance Summary

The initial QAPP for this case study, "Hydraulic Fracturing Retrospective Case Study, Bakken Shale, Killdeer and Dunn County," was approved by the designated EPA QA Manager on June 20, 2011 (US EPA, 2011i). A revision to the QAPP was made before the second sampling event and was approved on August 31, 2011, to address the collection of isotopic samples; revised sampling protocols for domestic, supply, and municipal wells; and analytical lab information. Another QAPP revision has been submitted for review by QA staff in preparation for the third sampling event. There have been no significant deviations from the QAPPs during earlier sampling events, and therefore no impact to data quality. A field TSA was conducted on July 19, 2011; no findings were identified. See Section 7.1.1 for information related to the laboratory TSAs.

As results are reported and raw data are provided from the laboratories, ADQs will be performed to verify that the quality requirements specified in the approved QAPP were met. Data will be qualified if necessary, based on these ADQs. The results of these ADQs will be reported in the final report on this project.

7.4. Bradford County, Pennsylvania

7.4.1. Project Introduction

Bradford County is a rural county in northeastern Pennsylvania with an approximate total population of 63,000 and an average population density of 55 people per square mile (USCB, 2010a). As shown in Figure 32, the Marcellus Shale underlies Bradford County, extending through much of New York, Pennsylvania, Ohio, and West Virginia. Recently, natural gas drilling in the Marcellus Shale has increased significantly in northeastern Pennsylvania, including Bradford County.

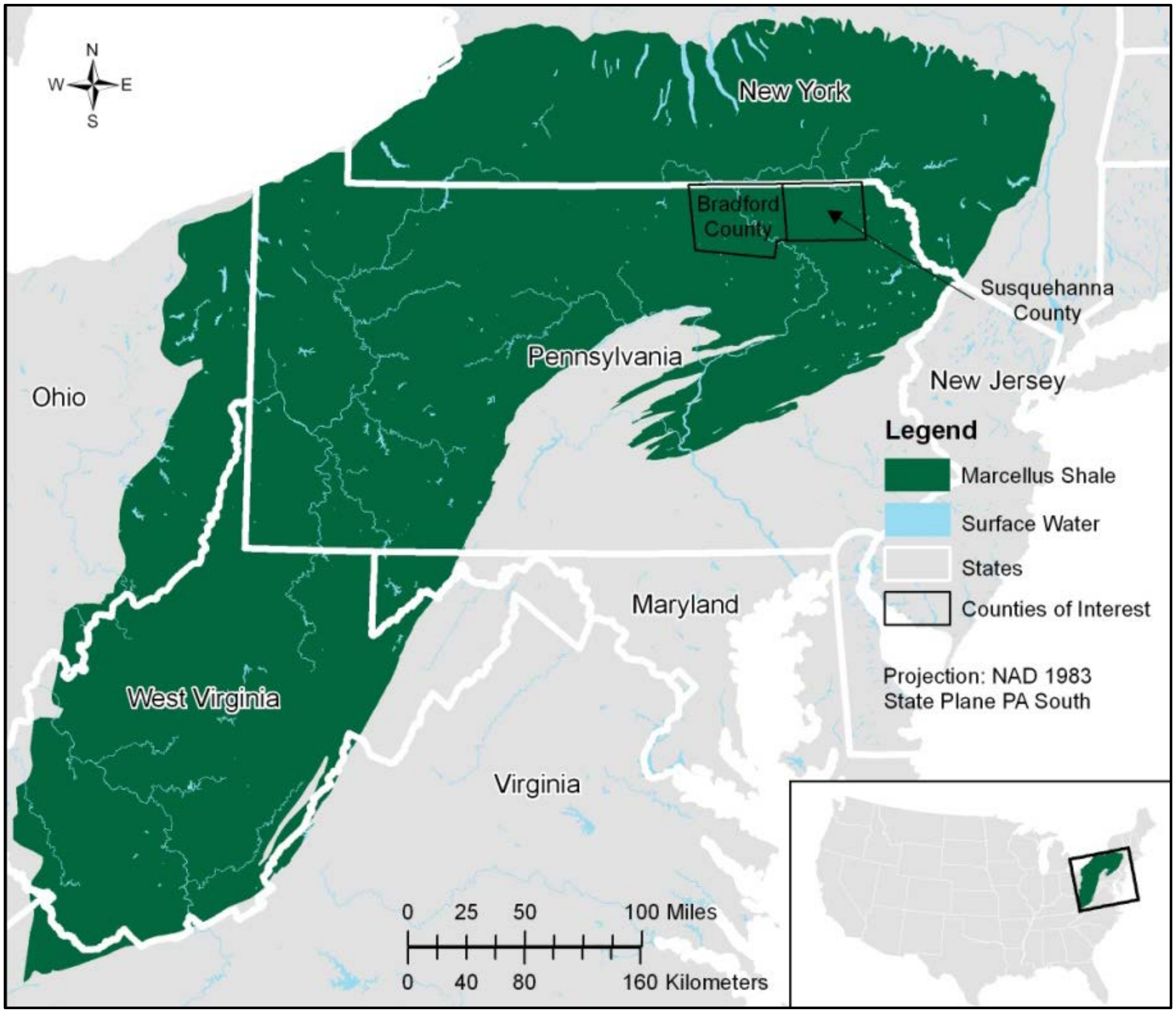

Figure 32. Extent of the Marcellus Shale, which underlies large portions of New York, Ohio, Pennsylvania, and West Virginia (US EIA, 2011d; USCB, 2012a, c). The case study focuses on reported changes in drinking water quality in Bradford County, Pennsylvania, with a few water samples taken in neighboring Susquehanna County.

The EPA chose Bradford County, and parts of neighboring Susquehanna County,[78] as a retrospective case study location because of the extensive hydraulic fracturing activities occurring there, coincident with the large number of homeowner complaints regarding the appearance, odor, and possible health impacts associated with water from domestic wells. Additionally, the Pennsylvania Department of Environmental Protection has issued notices of violation for infractions at wells in this area, including a gas well blowout in Leroy Township of Bradford County in April 2011 that released a reported 10,000 gallons of flowback and produced water (SAIC Energy Environment & Infrastructure LLC and Groundwater & Environmental Services Inc., 2011). Initial sampling locations for this retrospective case study were chosen primarily based on individual homeowner complaints or concerns regarding potential adverse impacts to their well water from nearby hydraulic fracturing activities. If anomalies in ground water quality are found during sampling, all potential sources of contamination in the study area will be considered, including those not related to hydraulic fracturing.

7.4.2. Site Background

Geology. The geology of the study area has been extensively described in other studies and is summarized below (Carter and Harper, 2002; Milici and Swezey, 2006; Taylor, 1984; Williams et al., 1998). The Bradford County study area is underlain by unconsolidated deposits of glacial and post-glacial origin and the nearly flat-lying sedimentary bedrock of the Appalachian Basin. The glacial and post-glacial deposits consist of till, stratified drift, alluvium, and swamp deposits. The bedrock consists primarily of shale, siltstone, and sandstone of Devonian to Pennsylvanian age. The Devonian bedrock includes the Loch Haven and Catskill formations, both of which are important sources of drinking water in the study area. The Marcellus Shale, also known as the Marcellus Formation, is a Middle Devonian-age (Appendix D) shale with a black color, low density, and high organic carbon content. It occurs in the subsurface beneath much of Ohio, West Virginia, Pennsylvania, and New York (Figure 32). Smaller areas of Maryland, Kentucky, Tennessee, and Virginia are also underlain by the Marcellus Shale. In Bradford County, the Marcellus Shale generally lies 4,000 to 7,000 feet below the surface and ranges in thickness from 150 to 300 feet (Marcellus Center for Outreach and Research, 2012a, b). The Marcellus Shale is part of a transgressive sedimentary package, formed by the deposition of terrestrial and marine material in a shallow, inland sea. It is underlain by the sandstones and siltstones of the Onondaga Formation and overlain by the carbonate rocks of the Mahantango Formation.

Within the Marcellus Shale, natural gas occurs within the pore spaces of the shale, within vertical fractures or joints of the shale, and adsorbed onto mineral grains and organic material. An assessment conducted by the USGS in 2011 suggested that the Marcellus Shale contains an estimated 84 trillion cubic feet of technically recoverable natural gas (Coleman et al., 2011).

[78] Four wells were sampled in Susquehanna County during the first round of sampling. Soon after, EPA Region 3 began an investigation of potential drinking water contamination in Dimock, located in Susquehanna County (see http://www.epa.gov/aboutepa/states/pa.html). In order to avoid duplication of effort, this case study focuses on reported changes in drinking water quality in Bradford County. Subsequent sampling for this case study has been, and will continue to be, done in Bradford County.

Water Resources. The average precipitation in Bradford County is 33 inches per year. Summer storms produce about half of this precipitation; the remainder of the precipitation, and much of the ground water recharge, occurs during winter and spring (PADEP, 2012). Surface water in the study area is part of the Upper Susquehanna River Basin. The main branches of the Susquehanna River flow to the south, while the smaller tributaries are constrained by the northeast-southwest orientation of the Appalachian Mountains. Stratified drift aquifers and the Loch Haven and Catskill bedrock formations serve as primary ground water drinking sources in the study area. Glacial till is also tapped as a drinking water source at some locations (Williams et al., 1998). These resources provide water for domestic use, municipal water, manufacturing, irrigation, and hydraulic fracturing.

The stratified drift aquifers in Bradford County occur as either confined or unconfined aquifers. The confined aquifers in the study area are composed of sand and gravel deposits of glacial, ice-contact origin and are typically buried by pro-glacial lake deposits; the unconfined aquifers are composed of sand and gravel deposited by glacial outwash or melt-waters. Depth to ground water varies throughout Bradford County and ranged from 1 to 300 feet for the wells sampled in the study. The median specific capacity of confined stratified drift aquifers is 11 gallons per minute per foot; the median specific capacity of unconfined stratified drift aquifers is 24 gallons per minute per foot (Williams et al., 1998). The specific capacity of wells completed in till or bedrock is typically 10 times lower than in the stratified drift aquifers.

Ground water in the study area is generally of two types: a calcium bicarbonate type in zones of unconfined flow and a sodium chloride type in zones of confined flow. Data from Williams et al. (1998) show that water wells completed in zones with more confined flow contain higher TDS (median concentration of 830 milligrams per liter), dissolved barium (median concentration of 2.0 milligrams per liter), and dissolved chloride (median concentration of 349 milligrams per liter) compared to zones with unconfined flow. This is also true for concentrations of iron and manganese in the study area. Table 53 presents a summary of median and maximum concentrations of inorganic parameters in Bradford County ground water, based on the study conducted by Williams et al. (1998).

Table 53. Background (pre-drill) water quality data for ground water wells in Bradford County, Pennsylvania (Williams et al., 1998).

Parameter	Pre Drill Data		
	Median Concentration (milligrams per liter)	Maximum Concentration (milligrams per liter)	Number of Samples
Arsenic	0.009	0.072	16
Barium	0.175	98	50
Chloride	11	3,500	93
Iron	0.320	15.9	95
Manganese	0.120	1.03	77
TDS	246	6,100	102
pH (pH units)	7.25	8.8	102

Naturally high levels of TDS, barium, and chloride found in ground water make it difficult to assess the potential impacts of hydraulic fracturing activities in this part of the country since these analytes would normally serve as indicators of potential impacts. In addition, methane occurs naturally in ground water in the study area, making an assessment of potential impacts of methane due to hydraulic fracturing on drinking water resources more challenging than at other study locations.

Oil and Gas Exploration and Production. Gas drilling to depths of the Marcellus Shale and beyond dates back to the 1930s, although at that time, the Marcellus Shale was of little interest as a source of gas. Instead, gas was sought primarily from sandstone and limestone deposits, and the Marcellus Shale was only encountered during drilling to deeper targeted zones like the Oriskany Sandstone. Upon penetrating the Marcellus Shale, significant but generally short-lived gas flow would be observed. With the advent of modern hydraulic fracturing technology and the increasing price of gas, the Marcellus Shale has become an economical source of natural gas with the potential to produce several hundred trillion cubic feet (Milici and Swezey, 2006). In July 2008, there were only 48 active permitted natural gas wells in Bradford County; by January 2012, there were 2,015 (Bradford County Government, 2012). The wells are located throughout the county with an average density of actively permitted wells of 1.8 wells per square mile.

7.4.3. Research Approach

Methods for sampling ground water and surface water are described in detail in the QAPP (US EPA, 2012m). The primary objective of this case study is to determine if ground water resources have been impacted, and whether or not those impacts were caused by hydraulic fracturing activities or other sources. Water samples have been taken from domestic wells, springs, ponds, and streams near gas well pads. Figure 33 shows the sampling locations, which were primarily chosen based on individual homeowner complaints or concerns regarding potential adverse impacts to water resources from nearby hydraulic fracturing activities.

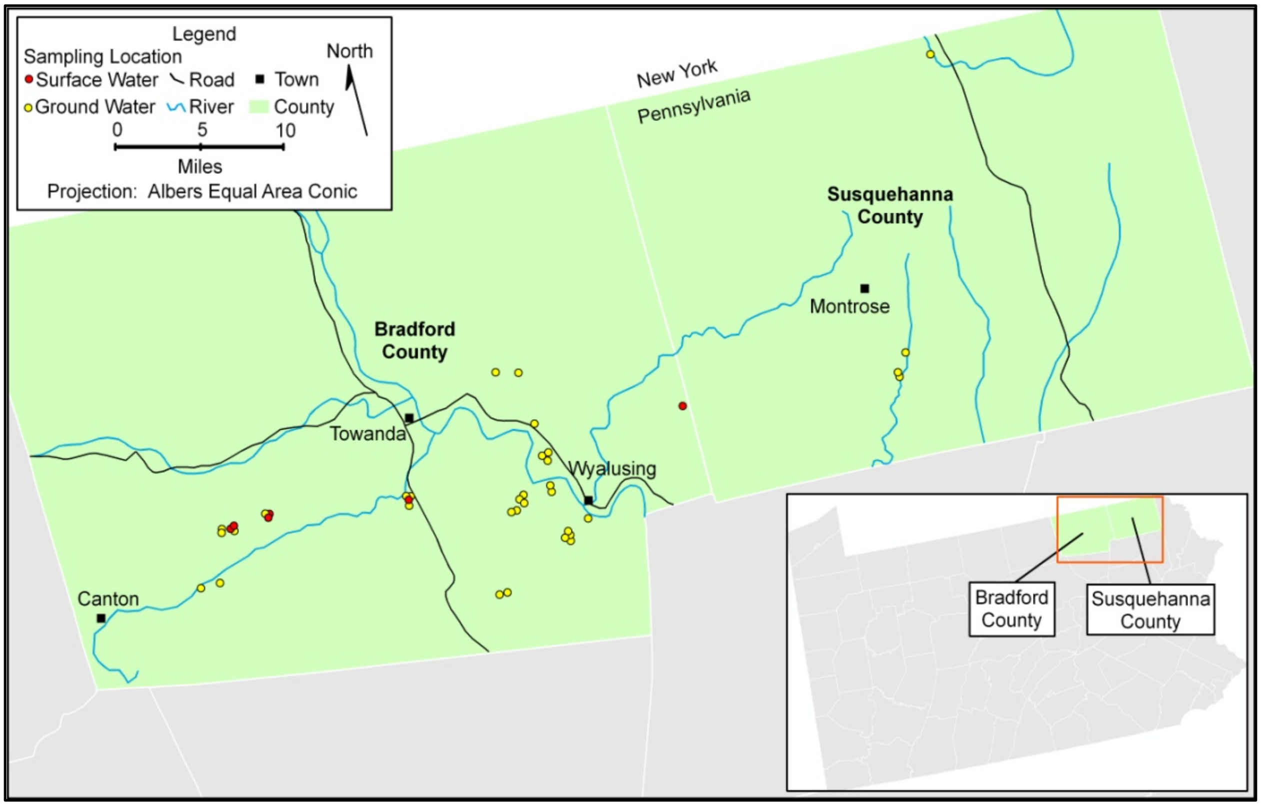

Figure 33. Location of sampling sites in Bradford and Susquehanna Counties, Pennsylvania. Samples were taken in Susquehanna County during the first round of sampling. Later rounds of sampling are focused only in Bradford County.

In addition to the analytes described in Section 7.1.1, the stable isotope compositions of carbon and hydrogen in dissolved methane and of carbon in dissolved inorganic carbon are being measured to determine the potential origin of the methane (i.e., biogenic versus thermogenic).[79] Since methane is known to be naturally present in the ground water of northeastern Pennsylvania, it is critical to understand the origin of any methane detected as part of this case study. Samples are also being analyzed for radium-226, radium-228, and gross alpha and beta radiation, as they may be potential indicators of hydraulic fracturing impacts to ground water in northeast Pennsylvania. Together, these measurements support the objective of determining if ground water resources have been impacted by hydraulic fracturing activities or other sources of contamination.

7.4.4. Status and Preliminary Data

Two rounds of sampling have been completed from 34 domestic wells, two springs, one pond, and one stream. The first sampling round was conducted in October and November of 2011 and the second round in April and May of 2012. The locations of sampling sites are displayed in Figure 33.

[79] Biogenic methane is formed as methane-producing microorganisms chemically break down organic material. Thermogenic methane results from the geologic formation of fossil fuel.

7.4.5. Next Steps

A third round of sampling to verify data collected from the first two rounds of sampling is already planned. Additional sampling locations may be included and there may be future rounds of sampling as analytical data from the first three rounds are evaluated and additional pertinent information becomes available. More focused investigations may also be conducted, if warranted, at locations where potential impacts associated with hydraulic fracturing are suspected.

7.4.6. Quality Assurance Summary

The initial QAPP for this case study, "Hydraulic Fracturing Retrospective Case Study, Bradford-Susquehanna Couties, PA," was approved by the designated EPA QA Manager on October 3, 2011 (US EPA, 2012m). A revision to the QAPP was made prior to the second sampling event and was approved on April 12, 2012, to address the addition of analytes such as radium-226, radium-228, lithium, and thorium; updated project organization and accreditation information; and clarification on some sampling and laboratory QA/QC issues. There have been no significant deviations from the QAPP during any sampling event, and therefore no impact to data quality. A field TSA was conducted on October 27, 2011; no findings were identified. See Section 7.1.1 for information related to the laboratory TSAs.

As results are reported and raw data are provided from the laboratories, ADQs are performed to verify that the quality requirements specified in the approved QAPP were met. Data will be qualified if necessary, based on these ADQs. The results of these ADQs will be reported in the final report on this project.

7.5. *Washington County, Pennsylvania*

7.5.1. Project Introduction

Washington County, located about 30 miles southwest of Pittsburgh, Pennsylvania, has a population of about 208,000 with approximately 240 people per square mile (USCB, 2010e). Figure 34 shows its position in the western region of the Marcellus Shale. Recently, oil and gas exploration and production in this area have increased, primarily due to production of natural gas from the Marcellus Shale using hydraulic fracturing.

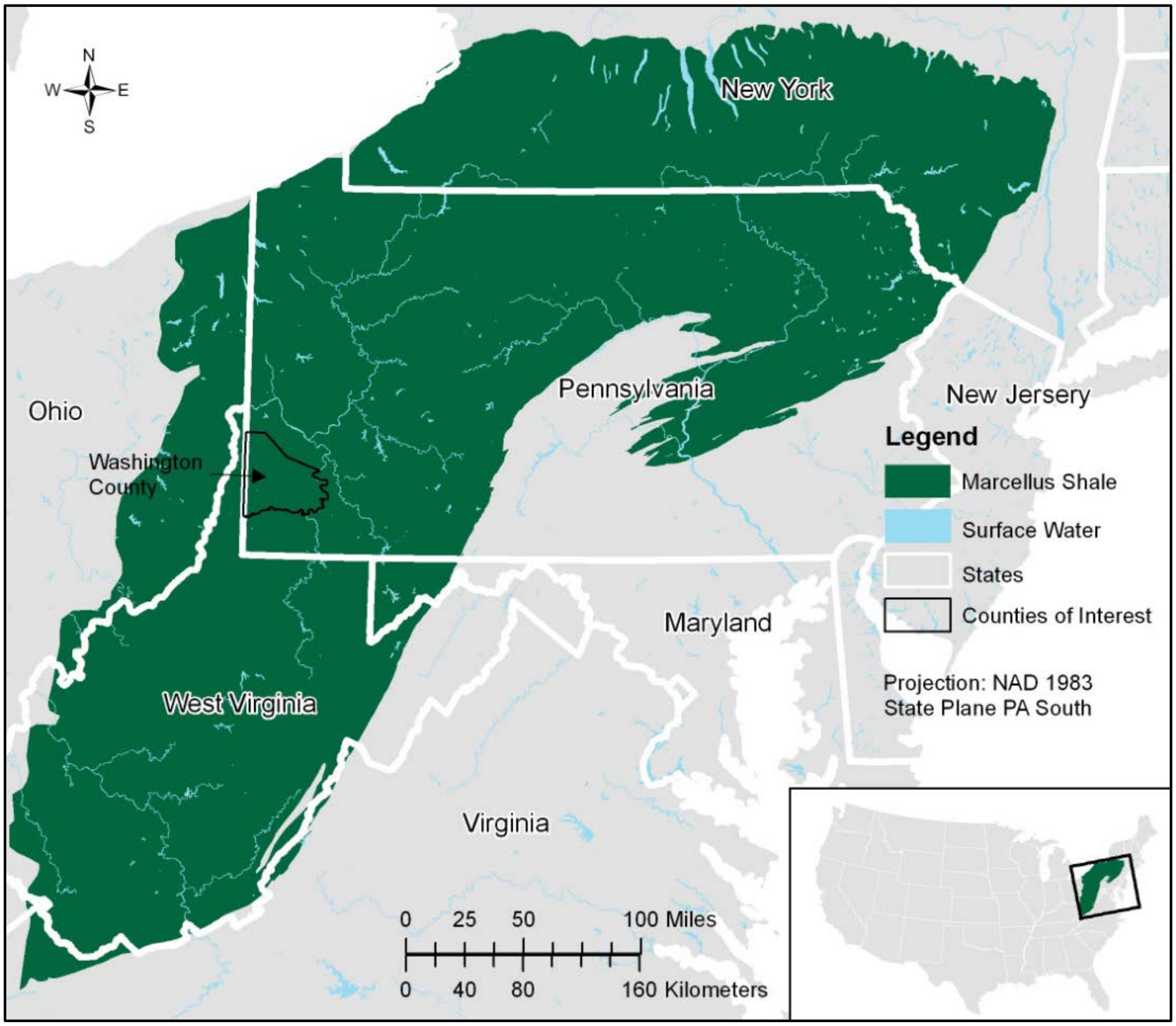

Figure 34. Extent of the Marcellus Shale, which underlies large portions of New York, Ohio, Pennsylvania, and West Virginia (US EIA, 2011d; USCB, 2012a, c). The case study focuses on reported changes in drinking water quality and quantity in Washington County, Pennsylvania.

The location of this case study was chosen in response to homeowner complaints about changes to water quality and water quantity in Washington County. Residents in several areas of Washington County have reported impacts to their private drinking water wells, specifically increased turbidity, discoloration of sinks, and transient organic odors. Sampling locations were selected in May 2011 by interviewing individuals about their water quality and the timing of any possible water quality changes in relation to gas production activities. Potential sources of ground water and surface water contamination under consideration at this case study site may include activities associated with oil and gas production (such as leaking or abandoned pits), gas well completion and enhancement techniques, and improperly plugged and abandoned wells, as well as activities associated with residential and agricultural practices.

7.5.2. Site Background

Geology. Washington County, like Bradford County, is located in the Appalachian Basin. The geology of this area of Pennsylvania consists of thick sequences of Paleozoic Era (Appendix D) sedimentary formations that dip and thicken to the southeast toward the basin axis. The surface geology in Washington County consists of Quaternary alluvial deposits, predominantly in stream valleys of the county. Alluvial deposits are generally less than 60 feet thick and consist of clay, silt, sand, and gravel derived from local bedrock. The formations of the Appalachian Basin are derived from a variety of clastic and biochemical sedimentary deposits, ranging from terrestrial swamps to near-shore environments and deep marine basins, which created shales, limestones, sandstones, coalbeds, and other sedimentary rocks (Shultz, 1999). As previously noted, the Marcellus Shale formation is of particular importance to recent gas exploration and production in the Appalachian Basin. In Washington County, the depth to the Marcellus Shale ranges from about 5,000 to 7,000 feet below ground surface (Marcellus Center for Outreach and Research, 2012a). The thickness of the Marcellus Shale in Washington County is less than 150 feet (Marcellus Center for Outreach and Research, 2012b).

Water Resources. The rivers and streams of Washington County drain into the Ohio River to the west. Drinking water aquifers in the county exist in both the alluvial deposits overlying bedrock in the stream valleys and in the bedrock. Ground water flow in the shallow aquifer system generally follows the topography, moving from recharge areas near hilltops to discharge areas in valleys.

Background information on the geology and hydrology of Washington County is summarized from reports published by Newport (1973) and Williams et al. (1993). Ground water in Washington County occurs in both confined and unconfined aquifers, with well yields ranging from a fraction of a gallon per minute to over 350 gallons per minute. In this area, water-bearing zones are generally no deeper than 150 feet below ground surface, and the depth to water varies from 20 to 60 feet below land surface depending on topographic setting. In addition to alluvial aquifers, ground water is derived from bedrock aquifers, including the Monongahela Group, the Conemaugh Group, and the Greene and Washington formations, which consist of limestones, shales, and sandstone units. In general, ground water derived from these formations has yields ranging from less than 1 to over 70 gallons per minute, and the formations range in depth from less than 40 feet to over 400 feet. The Conemaugh Group generally provides the greatest yield; the median yield for wells in this aquifer is 5 gallons per minute.

The quality of ground water in Washington County is variable and depends on factors such as formation lithology and residence time. For example, recharge ground water sampled from hilltops and hillsides is typically calcium-bicarbonate type and usually low in TDS (about 500 milligrams per liter). Ground water from valley settings in areas of discharge is typically sodium-bicarbonate or sodium-chloride type, with higher TDS values (up to 2,000 milligrams per liter). Williams et al.

(1993) report that background concentrations of iron and manganese in the ground water from Washington County are frequently above the EPA's secondary MCLs: over 33% of water samples had iron concentrations greater than 0.3 milligrams per liter, and 30% of water samples had manganese concentrations above 0.05 milligrams per liter. Hard water was also reported as being a common problem in the county, with TDS levels in more than one-third of the wells sampled by Williams et al. (1993) exceeding 500 milligrams per liter. Arsenic, cadmium, chromium, copper, lead, mercury, selenium, silver, and zinc were also detected at low levels. Historically, ground water quality in Washington County has been altered due to drainage from coal mining operations (Newport, 1973). Additionally, fresh water aquifers in some locations have been contaminated by brine from deeper non-potable aquifers through historic oil and gas wells that were improperly abandoned or have corroded casings (Newport, 1973).

Oil and Gas Exploration and Production. The oil and gas development in Washington County dates back to the 1800s, but generally did not target the Marcellus Shale (Ashley and Robinson, 1922). The first test gas well into the Marcellus Shale was drilled in Mount Pleasant Township in Washington County in 2003 and was hydraulically fractured in 2004. Data provided by the Pennsylvania Department of Environmental Protection indicate that the number of permitted gas wells in the Washington County area of the Marcellus Shale increased rapidly, from 10 wells in 2005 to 205 wells in 2009 (MarcellusGas.Org, 2012b). From 2009 to 2012, the number of newly permitted wells per year has remained below 240 (MarcellusGas.Org, 2012c). The anticipated water usage for all permitted wells in Washington County is estimated to be nearly 5 billion gallons (MarcellusGas.Org, 2012a).

7.5.3. Research Approach

Methods for sampling ground water and surface water are described in detail in the QAPP (US EPA, 2012n). Samples have been taken from domestic wells and surface water bodies. The EPA chose sampling locations by interviewing individuals about their water quality and the timing of water quality changes in relation to gas production activities. The locations of sampling sites are shown in Figure 35.

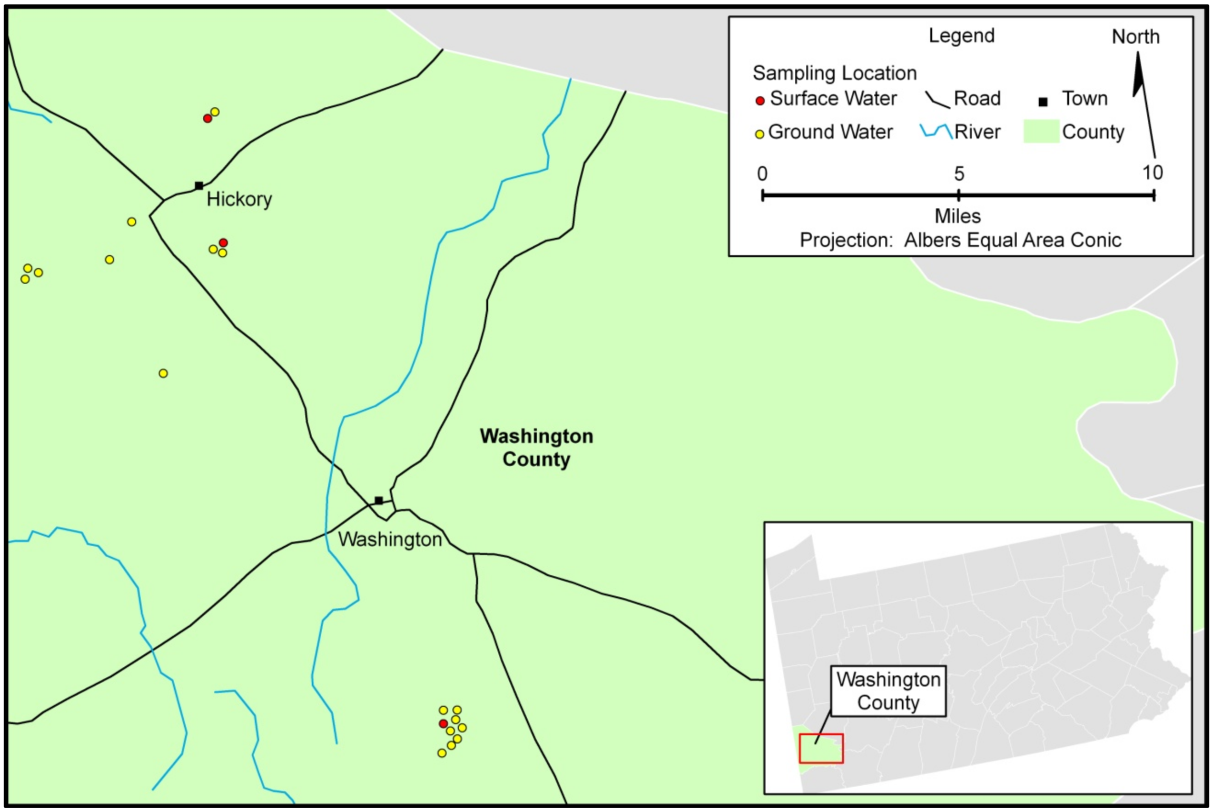

Figure 35. Sampling locations in Washington County, Pennsylvania.

Water samples collected at these locations are being analyzed for the chemicals listed in Section 7.1.1 as well as the chemicals listed in the QAPP (US EPA, 2012n). Together these measurements support the objective of determining if ground water resources have been impacted by hydraulic fracturing activities, or other sources of contamination.

7.5.4. Status and Preliminary Data

Two rounds of sampling have been completed: the first in July 2011 and the second in March 2012. During July 2011, 13 domestic wells and three surface water locations (small streams and spring discharges) were sampled. During March 2012, 13 domestic wells and two surface water locations were sampled. The locations of sampling sites are displayed in Figure 35.

7.5.5. Next Steps

Additional sampling rounds will be conducted to verify data collected from the first two rounds of sampling. Additional sampling locations may be included in the future as analytical data is evaluated and additional pertinent information becomes available. More focused investigations may also be conducted, if warranted, at locations where impacts associated with hydraulic fracturing may have occurred.

7.5.6. Quality Assurance Summary

The initial QAPP for this case study, "Hydraulic Fracturing Retrospective Case Study, Marcellus Shale, Washington County, PA," was approved by the designated EPA QA Manager on July 21, 2011 (US EPA, 2012n). A revision to the QAPP was made before the second sampling event and was approved on March 5, 2012, to update project organization, lab accreditation information, sampling methodology, to add radium isotope analyses and gross alpha/beta analyses, to modify critical analytes, and to change the analytical method for determining water isotope values. There have been no significant deviations from the QAPP during any sampling event, and therefore no impact on data quality. A field TSA was conducted on March 26, 2011; no findings were identified. See Section 7.1.1 for information related to the laboratory TSAs.

As results are reported and raw data are provided from the laboratories, ADQs are performed to verify that the quality requirements specified in the approved QAPP were met. Data will be qualified if necessary, based on these ADQs. The results of these ADQs will be reported in the final report on this project.

7.6. Wise County, Texas

7.6.1. Project Introduction

Wise County, Texas, is mostly rural, with a total population of about 60,000 and about 66 people per square mile (USCB, 2010f). Current gas development activities in Wise County are in the Barnett Shale, which is an unconventional shale in the Fort Worth Basin adjoining the Bend Arch Basin of north-central Texas. Figure 36 shows the extent of the Barnett Shale in Texas. In recent years, gas production in Wise County has increased due to improvements in horizontal drilling and hydraulic fracturing technologies.

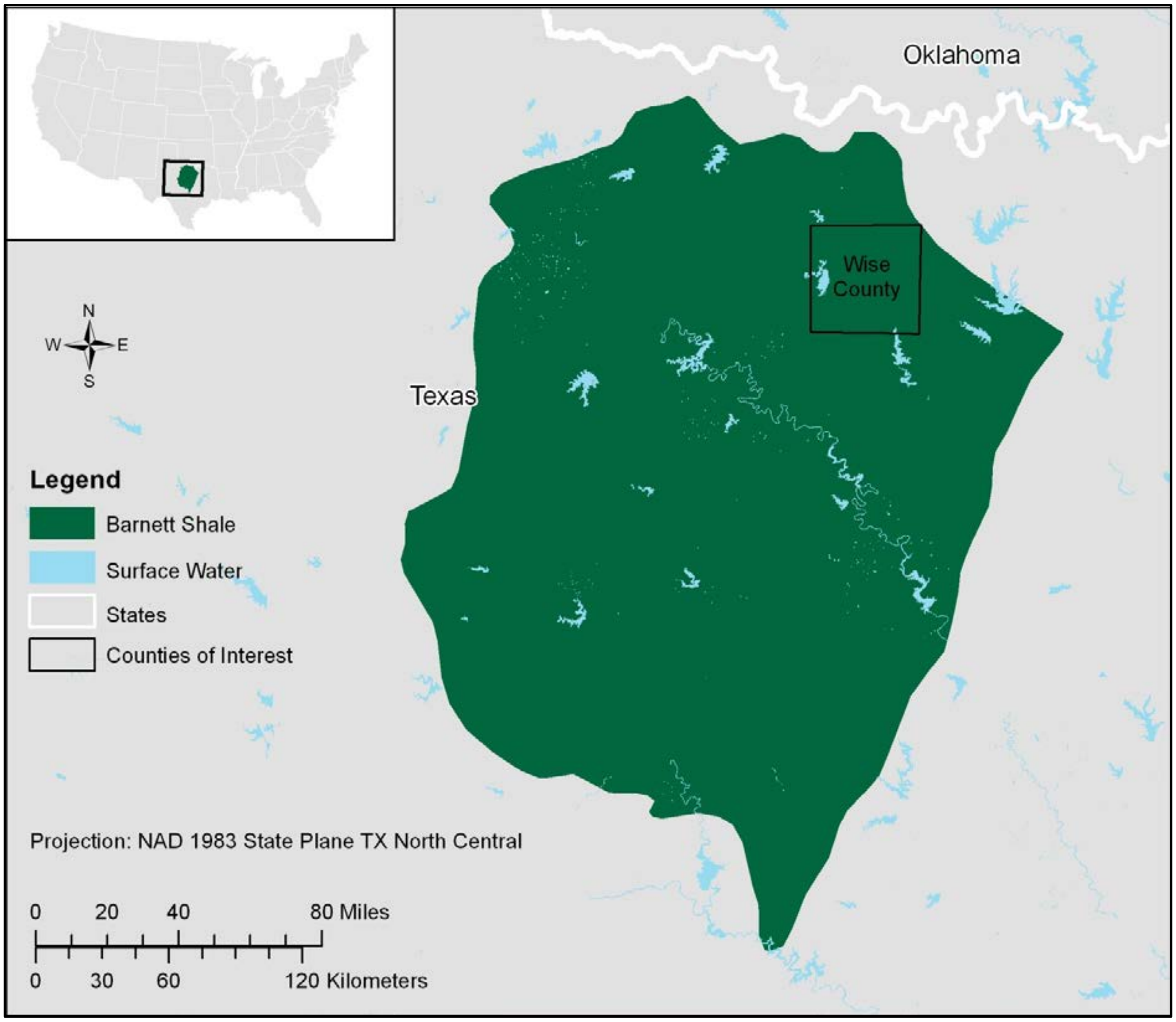

Figure 36. Extent of the Barnett Shale in north-central Texas (US EIA, 2011e; USCB, 2012a, c). The case study focuses on three distinct locations within Wise County.

The intent of this case study is to investigate homeowner concerns about changes in the ground water quality in Wise County that may be related to the recent increase in the hydraulic fracturing of oil and gas wells. Sampling locations in Wise County were chosen based on reported complaints of changes in drinking water quality and are clustered in three distinct locations: two near Decatur and one near Alvord. Homeowners in the two locations near Decatur reported changes in water quality, including changes in turbidity, color, smell, and taste. Homeowners near Alvord also reported changes in drinking water quality, although no more specific concerns were identified. Concerns about potential hydraulic fracturing impacts to ground water resources in Wise County are related to flowback fluid discharge to shallow aquifers, gas migration to shallow aquifers, spills on well pads, and leaking impoundments. Residential or agricultural practices, or aquifer drawdown unrelated to oil and gas development, may also be sources of ground water contamination at these sites.

7.6.2. Site Background

Geology. Wise County is located in the Bend Arch-Fort Worth Basin, which was formed during the late Paleozoic Ouachita Orogeny by the convergence of Laurussia and Gondwana in a narrow, restricted, inland seaway (Bruner and Smosna, 2011). The stratigraphy of the Bend Arch-Fort Worth Basin is characterized by limestones, sandstones, and shales. The Barnett Shale is of Mississippian age (Appendix D) and extends throughout the Bend Arch-Fort Worth Basin: south from the Muenster Arch, near the Oklahoma border, to the Llano Uplift in Burnet County and west from the Ouachita Thrust Front, near Dallas, to Taylor County (Bruner and Smosna, 2011). The Barnett Shale ranges from about 50 to 1,000 feet thick and occurs at depths ranging from 4,000 to 8,500 feet (Bruner and Smosna, 2011). In the northeastern portion of the Fort Worth Basin, the Barnett Shale is divided by the presence of the Forestburg Limestone, but this formation tapers out toward the southern edge of Wise County (Bruner and Smosna, 2011). The Barnett Shale is bounded by the Chappel Limestone below it and the Marble Falls Limestone above it (Bruner and Smosna, 2011). A recent estimate of the potential total gas yield was 820 billion cubic feet of gas per square mile, which is a significant increase from earlier estimates (Bruner and Smosna, 2011).

Water Resources. Wise County is drained by the Trinity River. Residents in the county often rely on the Trinity Aquifer as a major source of drinking water. In addition to drinking water, the Trinity Aquifer is also used for irrigation, industrial water, and hydraulic fracturing source water. The aquifer is composed of three formations, deposited in the Cretaceous: Paluxy, Glen Rose, and Twin Mountain (Nordstrom, 1982; Reutter and Dunn, 2000; Scott and Armstrong, 1932). In the northern part of Wise County, the Glen Rose formation pinches out, leaving only the Paluxy and Twin Mountain Formations, which together are occasionally referred to as the Antlers Formation (Nordstrom, 1982; Reutter and Dunn, 2000). The composition of the Paluxy Formation is fine sand, sandy shale, and shale and yields small to moderate quantities of water (Nordstrom, 1982). The Glen Rose Formation is composed of limestone, marl, shale, and anhydrite. The Glen Rose yields small quantities of water in localized areas (Nordstrom, 1982). Finally, the composition of the Twin Mountain Formation is fine to coarse sand, shale, clay, and basal gravel and conglomerate. This formation yields moderate to large quantities of water (Nordstrom, 1982). The Trinity Aquifer is overlain by the Walnut Creek Formation and is underlain by Graham Formation, both of which act as confining layers (Scott and Armstrong, 1932). Before modern water usage, it was artesian.

Table 54 summarizes background water quality data for the Trinity Aquifer in Wise County (Reutter and Dunn, 2000). The water quality is expected to be slightly different in the northern portion of the county than the southern portion of the county due to the “pinching out” of the Glen Rose Formation. From the reported data, the major water types in Wise County are calcium bicarbonate, calcium chloride, and sodium bicarbonate (Reutter and Dunn, 2000). All three water types are present in northern Wise County, but only the calcium bicarbonate and calcium chloride water types were observed in southern Wise County. The data collected at study locations will be compared to this compiled background data as part of the initial screening to determine if any contamination has occurred in study locations.

Table 54. Background water quality data for all of Wise County, Texas, and its northern and southern regions (Reutter and Dunn, 2000). Range of concentrations shown, with median values reported in parentheses.

Parameter	Units	Concentration Ranges		
		Wise County	North Wise County	South Wise County
Alkalinity	mg $CaCO_3$/L	130–430 (335)	190–430 (330)	130–420 (360)
Aluminum	µg/L	1–5 (2)	2–5 (2)	1–5 (2)
Ammonia	mg N/L	<0.01–1.10 (0.06)	<0.01–0.57 (0.6)	0.01–1.10 (0.10)
Antimony	µg/L	<1	<1	<1
Arsenic	µg/L	<1–4 (2)	<1–4 (3)	<1–2 (2)
Barium	µg/L	24–990 (95)	28–990 (95)	24–200 (94)
Beryllium	µg/L	<1	<1	<1
Bicarbonate	mg HCO_3/L	160–527 (407)	230–527 (406)	160–517 (424)
Bromide	mg/L	0.03–8.40 (0.22)	0.03–8.40 (0.18)	0.03–3.00 (0.30)
Cadmium	µg/L	<1	<1	<1
Calcium	mg/L	1–570 (88)	62–570 (110)	1–200 (70)
Chloride	mg/L	5–1,300 (45)	12–1,300 (194)	5–500 (49)
Chromium	µg/L	<1–8 (5)	<1–2 (1)	1–8 (5)
Cobalt	µg/L	<1	<1	<1
Copper	µg/L	<1–18 (5)	<1–8 (3)	<1–8 (7)
Fluoride	mg/L	<0.10–1.20 (0.20)	<0.10–0.60 (0.20)	<0.10–1.20 (0.20)
Iron	mg/L	<3–4,400 (10)	<3–4,400 (27)	<3–160 (9)
Lead	µg/L	<1–5 (2)	<1	<1–5 (2)
Magnesium	mg/L	1–86 (18)	2.8–65 (33)	1–86 (9)
Manganese	µg/L	<1–140 (27)	<1–140 (49)	<1–27 (4)
Molybdenum	µg/L	<1–2 (1)	<1	<1–2 (1)
Nickel	µg/L	<1–6 (1)	<1–6 (2)	<1–4 (1)
Nitrate + nitrite	mg N/L	<0.05–7.20 (1.70)	<0.05–7.20 (2.30)	<0.05–6.30 (1.25)
pH	pH units	6.6–9.1 (7.1)	6.7–7.8 (7.0)	6.6–9.1 (7.2)
Phosphate	mg P/L	<0.01–0.40 (0.03)	<0.01–0.03 (0.02)	<0.01–0.40 (0.04)
Potassium	mg/L	0.6–4.6 (2.4)	1–4.6 (2.7)	0.6–3.8 (1.9)
Selenium	µg/L	<1–14 (2)	<1–3 (2)	<1–14 (3)
Silica	mg/L	8.8–26 (19.5)	17–24 (20)	9–26 (19)
Silver	µg/L	<1	<1	<1
Sodium	mg/L	10–310 (58)	18–220 (51)	10–310 (87)

Table continued on next page

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Parameter	Units	Concentration Ranges		
		Wise County	North Wise County	South Wise County
Specific conductance	µS/cm	710–4,590 (913)	71–4,590 (911)	510–2,380 (914)
Sulfate	mg/L	10–250 (46)	26–250 (45)	10–160 (46)
Uranium	µg/L	<1–93 (4)	<1–93 (4)	<1–13 (5)
Zinc	µg/L	1–590 (18)	4–590 (18)	1–96 (18)

Oil and Gas Exploration and Production. Wise County has experienced a dramatic increase in gas production from the Barnett Shale since the late 1990s, concurrent with the recent improvements in hydraulic fracturing and horizontal drilling technologies (RRC, 2012). From 2003 to 2011, Wise County gas production increased almost 10-fold, from approximately 200 to 1,800 billion cubic feet (RRC, 2012).

7.6.3. Research Approach

A detailed description of this study's sampling methods and procedures can be found in the QAPP (US EPA, 2012p). Sampling in Wise County includes surface water, industrial wells, and homeowners' domestic wells in three general locations, as shown in Figure 37. Because of the standard water well design in Wise County,[80] it is not possible to sample directly from these drinking water wells, nor is it possible to measure water levels to establish ground water flow gradients and direction. Instead, both domestic and industrial wells are sampled at a tap as close to the wellhead as possible and before any water treatment has occurred.[81]

[80] The water wells in Wise County are sealed, with no access ports. To sample the wells directly, it would require a crane or drilling rig to pull the pump string out of the well, due to the weight of the pump string, safety concerns, and costs.

[81] To control for the possible effects of household plumbing, sampling of the domestic wells at or near the well head is done upstream of the home, and the sampled water never enters the home plumbing or water treatment systems. The wells are purged at 8–30 gallons per minute for at least 30 minutes before the flow is reduced. The initial purge is such that an estimated three screen volumes of water are purged from the well. After that, the purge rate is reduced to less than 2 liters per minute and is continued until stable geochemical parameters are obtained.

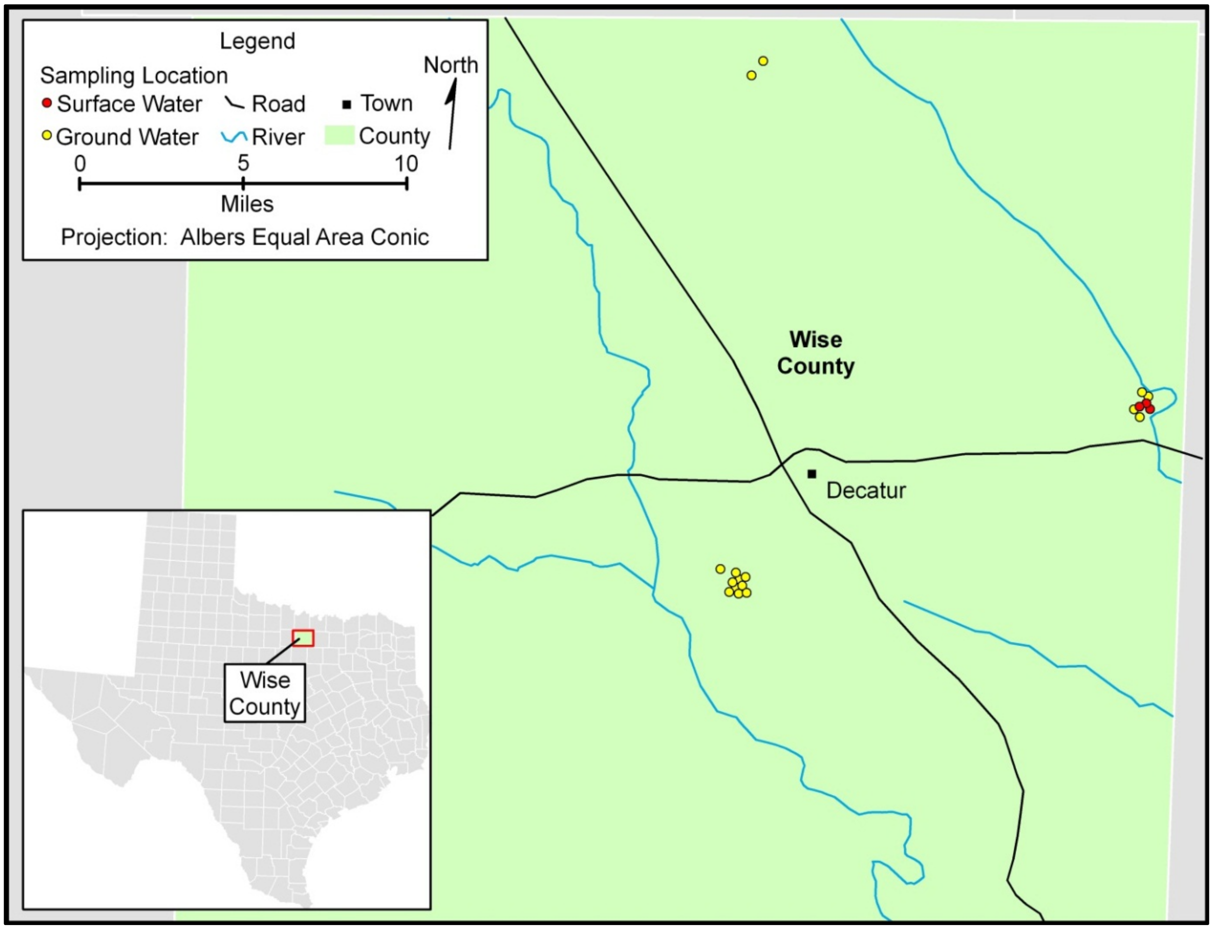

Figure 37. Location of sampling sites in Wise County, Texas.

Water samples collected at these locations are being analyzed for the chemicals listed in Section 7.1.1 as well as the chemicals listed in the QAPP (US EPA, 2012p). Together these measurements support the objective of determining if ground water resources have been impacted by hydraulic fracturing activities, or other sources of contamination.

7.6.4. Status and Preliminary Data

Two rounds of sampling have been conducted at all locations in Wise County: one round in September 2011 and one round in March 2012. The September 2011 sampling event included 11 domestic wells, one industrial well, and three surface water (pond) samples. The March 2012 sampling event included the same wells as the September 2011 sampling event, with an additional four domestic wells and the loss of one domestic well. The locations of all sampling sites are displayed in Figure 37.

7.6.5. Next Steps

Additional sampling rounds will be conducted to verify data collected from the first two rounds of sampling. Additional sampling locations may be included in the future as analytical data are evaluated and additional pertinent information becomes available. More focused investigations may also be conducted, if warranted, at locations where impacts may have occurred.

7.6.6. Quality Assurance Summary

The initial QAPP for this case study, "Hydraulic Fracturing Retrospective Case Study, Wise, TX," was approved by the designated EPA QA Manager on June 20, 2011 (US EPA, 2012p). A revision to the QAPP was made before the second sampling event and was approved on February 27, 2012. The revision included the addition of isotopic analysis, USGS laboratory information,[82] revised sampling locations, Region 8 laboratory accreditation status, geophysical measurement methods and QC, data qualifiers, personnel changes, and analytical method updates. A second revision was approved on May 25, 2012, for the next sampling event to include the Phase 2 sampling information, the method for qualifying field blanks, and the modified sampling schedule. The second QAPP revision also replaced EPA Method 200.7 with 6010C and replaced metals QC criteria with revised criteria. A third revision to the QAPP was approved on September 10, 2012, to add information on March 2012 sampling, add strontium and stable water isotopes to analytes list, and delete diesel range organics and gasoline range organics. The third QAPP revision also replaced EPA Method 6010C with 200.7.[83] There have been no significant deviations from the QAPP during any sampling event, and therefore no impact on data quality. A field TSA was conducted on September 21, 2011; no findings were identified. See Section 7.1.1 for information related to the laboratory TSAs.

As results are reported and raw data are provided from the laboratories, ADQs are performed to verify that the quality requirements specified in the approved QAPP were met. Data will be qualified if necessary, based on these ADQs. The results of these ADQs will be reported in the final report on this project.

[82] USGS provided isotope support for the Wise County retrospective case study. A detailed account of the role of USGS can be found in Appendix A of the Wise County QAPP.

[83] EPA Method 200.7 was referenced in the initial QAPP and the first QAPP revision. It was changed in the second QAPP revision to EPA Method 6010C, but since then it was determined by QA staff that the use of 200.7 as the "base" method was appropriate as 200.7 incorporates 6010C by reference.

8. Conducting High-Quality Science

The EPA ensures that its research activities result in high-quality science through the use of QA and peer review activities. Specific QA activities performed by the EPA ensure that the agency's environmental data are of sufficient quantity and quality to support the data's intended use. Peer review ensures that the data are sound and used appropriately. The use of QA measures and peer review helps ensure that the EPA conducts high-quality science that can be used to inform policymakers, industry, and the public.

8.1. Quality Assurance

All agency research projects that generate or use environmental data to make conclusions or recommendations must comply with the EPA QA program requirements. The EPA laboratories and external organizations involved with the generation or use of environmental data are supported by QA professionals who oversee the implementation of the QA program for their organization. To ensure scientifically defensible results, this study complies with the agency-wide Quality Policy CIO 2106 (US EPA, 2008), EPA Order CIO 2105.0 (US EPA, 2000a, c), the EPA's Information Quality Guidelines (US EPA, 2002), the EPA's Laboratory Competency Policy (US EPA, 2004a), and Chapter 13 of the Office of Research and Development's *Policies and Procedures Manual* (US EPA, 2006).

Given the cross-organizational nature of this study, a Quality Management Plan was developed (US EPA, 2012t) and a Program QA Manager was chosen to coordinate a rigorous QA approach and oversee its implementation across all participating organizations within the EPA. The Quality Management Plan defines the QA-related policies, procedures, roles, responsibilities, and authorities for the study and documents how the EPA will plan, implement, and assess the effectiveness of its QA and QC operations. In light of the importance and organizational complexity of the study, the Quality Management Plan was created to make certain that all research be conducted with integrity and strict quality controls.

The Quality Management Plan sets forth the following rigorous QA approach:

- Individual research projects must comply with agency requirements and guidance for QAPPs.
- TSAs and audits of data quality will be conducted for individual research projects as described in the QAPPs.
- Performance evaluations of analytical systems will be conducted.
- Products will undergo QA review. Applicable products may include reports, journal articles, symposium/conference papers, extended abstracts, computer products/ software/models/databases, and scientific data.
- Reports will have readily identifiable QA sections.

Research records will be managed according to EPA Records Schedule 501, "Applied and Directed Scientific Research"(US EPA, 2011c).

The Quality Management Plan applies to all research activities conducted under the EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. More information about specific QA protocols, including management, organization, quality-system components, personnel qualification and training, procurement of items and services, documentation and records, computer requirements, planning, implementation, assessment, and quality improvement, can be found in the Quality Management Plan.[84]

Project-specific details of individual research projects are documented in a QAPP. All work performed or funded by the EPA that involves the acquisition of environmental data must have an approved QAPP. The QAPP documents the planning, implementation, and assessment procedures for a particular project, as well as any specific QA and QC activities. It integrates all the technical and quality aspects of the project in order to provide a guide for obtaining the type and quality of environmental data and information needed for a specific decision or use. Quality assurance project plans are living documents that undergo revisions as needed. Individual QAPPs for the various research projects included in this study are available on the study website (http://www.epa.gov/hfstudy) and are summarized in Appendix C.

Regular technical assessments of project operation, systems, and data related to the study are conducted as detailed in the Quality Management Plan. A technical assessment is "a systematic and objective examination of a project to determine whether environmental data collection activities and related results comply with the project's QAPP, whether the activities are implemented effectively, and whether they are sufficient and adequate to achieve QAPP's data quality goals" (US EPA, 2000b). Assessment components include quality system assessments, technical system assessments, verification of data, audits of data quality, and surveillance. More details about assessments and audits required for this study can be found in the Quality Management Plan and project-specific QAPPs.

Quality Assurance and Projects Involving the Generation of New Data. Research projects that generate new data (e.g., case studies, laboratory studies, some toxicity assessments) will contribute to the growing body of scientific literature about environmental issues associated with hydraulic fracturing. The QA/QC procedures detailed in these QAPPs meet the requirements of the hydraulic fracturing Quality Management Plan, detailed above, and also focus on those practices necessary for assuring the quality of measurement data generated by the EPA. Samples must be collected, preserved, transported, and stored in a manner that retains their integrity; these issues are addressed in individual QAPPs. Also described in QAPPs are the methods used for sample analysis, including details about the appropriate frequency of calibration of analytical instrumentation and measurement devices. Quality control samples are identified that can be used to check for potential contamination of samples and to check for measurement errors that can be caused by difficult sample matrices. The QAPPs for generation of new data provide details on the logistics of who, where, when and how new data will be generated.

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[84] Research initiated prior to the implementation of the study-specific Quality Management Plan was conducted under Quality Management Plans associated with each of the EPA Office of Research and Development's individual labs and centers.

Quality Assurance and Projects Involving Existing Data. Research projects that involve acquiring and analyzing existing data (i.e., data that are not new data generated by or for the EPA) must conform to the requirements of the Quality Management Plan, including the development of a QAPP. The focus of QAPPs for existing data is on setting criteria that will filter out any data that are of insufficient quality to meet project needs. This starts with describing the process for locating and acquiring the data. How the data will be evaluated for their planned use and how the integrity of the data will be maintained throughout the collection, storing, evaluation, and analysis processes are also important features of a QAPP for existing data.

Quality Assurance and Report Preparation. Quality assurance requirements also extend to the two primary products of this study: this progress report and the report of results. As required by the Quality Management Plan, this progress report has undergone QA review before its release, and the report of results will do the same. These requirements serve to ensure that the reports are defensible and scientifically sound.

8.2. Peer Review

Peer review, an important part of every scientific study, is a documented critical review of a specific scientific and/or technical work product (e.g., paper, report, presentation). It is an in-depth assessment of the assumptions, calculations, extrapolations, alternate interpretations, methodology, acceptance criteria, and conclusions in the work product and the documents that support them. Peer review is conducted by individuals (or organizations) independent of those who performed the work and equivalent in technical expertise (US EPA, 2012e; US OMB, 2004). Feedback from the review process is used to revise the draft product to make certain the final work product reflects sound technical information and analyses.

Peer review can take many forms depending on the nature of the work product. Work products generated through the EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* will be subjected to both internal and external peer review. Internal peer review occurs when work products are reviewed by independent experts within the EPA, while external peer review engages experts outside of the agency, often through scientific journals, letter reviews, or *ad hoc* panels.

The EPA often engages the Science Advisory Board, an external federal advisory committee, to conduct peer reviews of high-profile scientific matters relevant to the agency. Members of an *ad hoc* panel convened under the auspices of the Science Advisory will provide comment on this progress report.[85] Panel members are nominated by the public and chosen based on factors such as technical expertise, knowledge, experience, and absence of any real or perceived conflicts of interest to create a balanced review panel. In August 2012, the EPA issued a *Federal Register* notice requesting public nominations for technical experts to form a Science Advisory Board *ad hoc* panel to provide advice on the status of the research described in this progress report (US EPA, 2012v). This panel is

[85] Information about this process is available at http://yosemite.epa.gov/sab/sabproduct.nsf/02ad90b136fc21ef85256eba00436459/b436304ba804e3f885257a5b00521b3b!OpenDocument.

also expected to review the report of results, which has been classified as a Highly Influential Scientific Assessment.[86]

[86] The Office of Management and Budget's Peer Review Bulletin (US OMB, 2004) defines Highly Influential Scientific Assessments as scientific assessments that could (1) have a potential impact of more than $500 million in any year or (2) are novel, controversial, or precedent-setting or have significant interagency interest. The Peer Review Bulletin describes specific peer review requirements for Highly Influential Scientific Assessments.

9. Research Progress Summary and Next Steps

This report describes the progress made for each of the research projects conducted as part of the EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. This chapter provides an overview of the progress made for each research activity as well as the progress made for each stage of the water cycle presented in Section 2.1. It also describes, in more detail, the report of results.

9.1. Summary of Progress by Research Activity

The EPA is using a transdisciplinary research approach to investigate the potential relationship between hydraulic fracturing and drinking water resources. This approach includes compiling and analyzing data from existing sources, evaluating scenarios using computer models, carrying out laboratory studies, assessing the toxicity associated with hydraulic fracturing-related chemicals, and conducting case studies.

Analysis of Existing Data. To date, data from seven sources have been obtained for review and ongoing analysis, including:

- Information provided by nine hydraulic fracturing service companies.
- 333 well files supplied by nine oil and gas operators.
- Over 12,000 chemical disclosure records from FracFocus, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.
- Spill reports from four different sources, including databases from the National Response Center, Colorado, New Mexico, and Pennsylvania.

As part of its literature review, the EPA has compiled, and continues to search for, literature relevant to the secondary research questions listed in Section 2.1. This includes documents provided by stakeholders and recommended by the Science Advisory Board during its review of the draft study plan.[87] A *Federal Register* notice requesting peer-reviewed data and publications relevant to the study, including information on advances in industry practices and technologies, has recently been published (US EPA, 2012u).

Scenario Evaluations. Potential impacts to drinking water sources from withdrawing large volumes of water in both a semi-arid and a humid river basin—the Upper Colorado River Basin in the west and the Susquehanna River Basin in the east—are being assessed. Additionally, complex computer models are being used to explore the possibility of subsurface gas and fluid migration from deep shale formations to overlying aquifers in six different scenarios. These scenarios include poor well

[87] Additional information on the Science Advisory Board review of the EPA's *Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* is available at http://www.epa.gov/hfstudy/peer-review.html.

construction and hydraulic communication via fractures (natural and created) and nearby existing wells. As a first step, the subsurface migration simulations will examine realistic scenarios to assess the conditions necessary for hydraulic communication rather than the probability of migration occurring. In a separate research project, the EPA is using surface water transport models to estimate concentrations of bromide and radium at public water supply intakes downstream from wastewater treatment facilities that discharge treated hydraulic fracturing wastewater.

Laboratory Studies. The ability to analyze and determine the presence and concentration of chemicals in environmental samples is critical to the EPA's study. In most cases, standard EPA methods are being used for laboratory analyses. In other cases, however, standard methods do not exist for the low-level detection of chemicals of interest or for use in the complex matrices associated with hydraulic fracturing wastewater. Where necessary, existing analytical methods are being tested, modified, and verified for use in this study and by others. Analytical methods are currently being tested and modified for several classes of chemicals, including glycols, acrylamides, ethoxylated alcohols, DBPs, radionuclides, and inorganic chemicals.

Laboratory studies focusing on the potential impacts of inadequate treatment of hydraulic fracturing wastewater on drinking water resources are being planned and conducted. The studies include assessing the ability of hydraulic fracturing wastewater to create brominated DBPs and testing the efficacy of common wastewater treatment processes on removing selected contaminants from hydraulic fracturing wastewater. Samples of surface water, raw hydraulic fracturing wastewater, and treated effluent have been collected for the source apportionment studies, which aim to identify the source of high chloride and bromide levels in rivers accepting treated hydraulic fracturing wastewater.

Toxicity Assessment. The EPA has evaluated data to identify chemicals reportedly used in hydraulic fracturing fluids from 2005 to 2011 and chemicals found in flowback and produced water. Appendix A contains tables of these chemicals, with over 1,000 chemicals identified. Chemical, physical, and toxicological properties have been compiled for chemicals with known chemical structures. Existing models are being used to estimate properties in cases where information is lacking. At this time, the EPA has not made any judgment about the extent of exposure to these chemicals when used in hydraulic fracturing fluids or found in hydraulic fracturing wastewater, or their potential impacts on drinking water resources.

Case Studies. Two rounds of sampling at all five retrospective case study locations have been completed. In total, water samples have been collected from over 70 domestic water wells, 15 monitoring wells, and 13 surface water sources, among others. A third round of sampling is expected to occur this fall in Las Animas and Huerfano Counties, Colorado; Dunn County, North Dakota; and Wise County, Texas. Additional sampling in Bradford and Washington Counties, Pennsylvania, is projected to take place in spring 2013.

The EPA continues to work with industry partners to plan and begin research activities for prospective case studies.

9.2. Summary of Progress by Water Cycle Stage

Figures 38 and 39 illustrate the research underway for each stage of the hydraulic fracturing water cycle. The fundamental research questions and research focus areas are briefly described below for each water cycle stage; for more detail on the stages of the hydraulic fracturing water cycle and their associated research projects, see Section 2.1.

Water Acquisition: What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources? Work in this area focuses on understanding the volumes and sources of water needed for hydraulic fracturing operations, and the potential impacts of water withdrawals on drinking water quantity and quality. Effects of recently emerging trends in water recycling will be considered in the report of results.

Chemical Mixing: What are the possible impacts of surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources? Spill reports from several databases are being reviewed to identify volumes and causes of spills of hydraulic fracturing fluids and wastewater. Information on the chemicals used in hydraulic fracturing fluids and their known chemical, physical, and toxicological properties has been compiled.

Well Injection: What are the possible impacts of the injection and fracturing process on drinking water resources? Work currently underway is focused on identifying conditions that may be associated with the subsurface migration of gases and fluids to drinking water resources. The EPA is exploring gas and fluid migration due to inadequate well construction as well as the presence of nearby natural faults and fractures or man-made wells.

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? As with chemical mixing, research in this area focuses on reviewing spill reports of flowback and produced water as well as collecting information on the composition of hydraulic fracturing wastewater. Known chemical, physical, and toxicological properties of the components of flowback and produced water are being compiled.

Wastewater Treatment and Waste Disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewater on drinking water resources? Work in this area focuses on evaluating treatment and disposal practices for hydraulic fracturing wastewater. Since some wastewater is known to be discharged to surface water after treatment in POTWs or commercial treatment systems, the EPA is investigating the efficacy of common treatment processes at removing selected components in flowback and produced water. Potential impacts to downstream public water supplies from discharge of treated hydraulic fracturing wastewater are also being investigated, including the potential for the formation of Br-DBPs.

Water Acquisition

Literature Review
Review and summarize literature on:
- Volumes and sources of water used in hydraulic fracturing fluids
- Local impacts to water availability in areas with hydraulic fracturing activity
- Water quality impacts from ground and surface water withdrawals

Service Company Analysis
Summarize data provided by nine hydraulic fracturing service companies on volumes and sources of water used in hydraulic fracturing fluids

Well File Review
Summarize data from 333 well files on volumes and source of water used in hydraulic fracturing fluids

FracFocus Analysis
Compile and summarize total water volumes reported in FracFocus by geographic location, well depth, water types, and oil/gas production

Chemical Mixing

Literature Review
Review and summarize literature on:
- Spills of hydraulic fracturing fluids or chemical additives
- Chemicals used in hydraulic fracturing fluids
- Environmental fate and transport of selected chemicals in hydraulic fracturing fluids

Spills Database Analysis
Compile and evaluate spill information from three state databases (CO, NM, PA) and one national database (NRC)

Service Company Analysis
Evaluate information on:
- Spills of hydraulic fracturing fluids or chemical additives
- Chemicals used in hydraulic fracturing fluids from 2005 to 2010

Well File Review
Evaluate spill data from 333 well files

FracFocus Analysis
Compile a list of chemicals reported in FracFocus and summarize chemical usage by frequency and geographic location

Well Injection

Literature Review
Review and summarize literature on possible subsurface migration due to:
- Faulty well construction
- Nearby natural or man-made conduits

Service Company Analysis
Review and summarize standard operating procedures for information on:
- Practices related to establishing the mechanical integrity of wells being hydraulically fractured
- Procedures used during injection of the fracturing fluid

Well File Review
Review well construction data found in well files to assess the effectiveness of current well construction practices at isolating the wellbore from surrounding ground water

Analysis of Existing Data
Scenario Evaluations
Laboratory Studies
Toxicity Assessment
Case Studies

Figure 38a. Summary of research projects underway for the first three stages of the hydraulic fracturing water cycle.

Water Acquisition → **Chemical Mixing** → **Well Injection** →

Water Acquisition

Water Availability Modeling

- Summarize data on water usage for hydraulic fracturing in a semi-arid climate (Upper Colorado River Basin) and a humid climate (Susquehanna River Basin)
- Use watershed models to explore water availability for public water supplies under a variety of scenarios, focusing on water usage in the Upper Colorado and Susquehanna River Basins

Chemical Mixing

Analytical Method Development

Develop analytical methods for the detection of selected chemicals reported to be in hydraulic fracturing fluids

Toxicity Assessment

Compile or estimate chemical, physical, and toxicological properties for chemicals with known chemical structures that are reported to be in hydraulic fracturing fluids

Retrospective Case Studies

Consider spills of hydraulic fracturing fluids as a possible source of reported changes in water quality of local drinking water wells

Well Injection

Subsurface Migration Modeling

Apply computer models to explore the potential for gas or fluid migration from:

- Incomplete well cementing or cement failure during hydraulic fracturing
- Nearby wells and existing faults

Retrospective Case Studies

Consider potential impacts to drinking water sources from:

- Relatively shallow hydraulic fracturing operations
- Release of hydraulic fracturing fluids during the injection process
- Poor well construction practices

Legend:

- Analysis of Existing Data
- Scenario Evaluations
- Laboratory Studies
- Toxicity Assessment
- Case Studies

Figure 38b. Summary of research projects underway for the first three stages of the hydraulic fracturing water cycle.

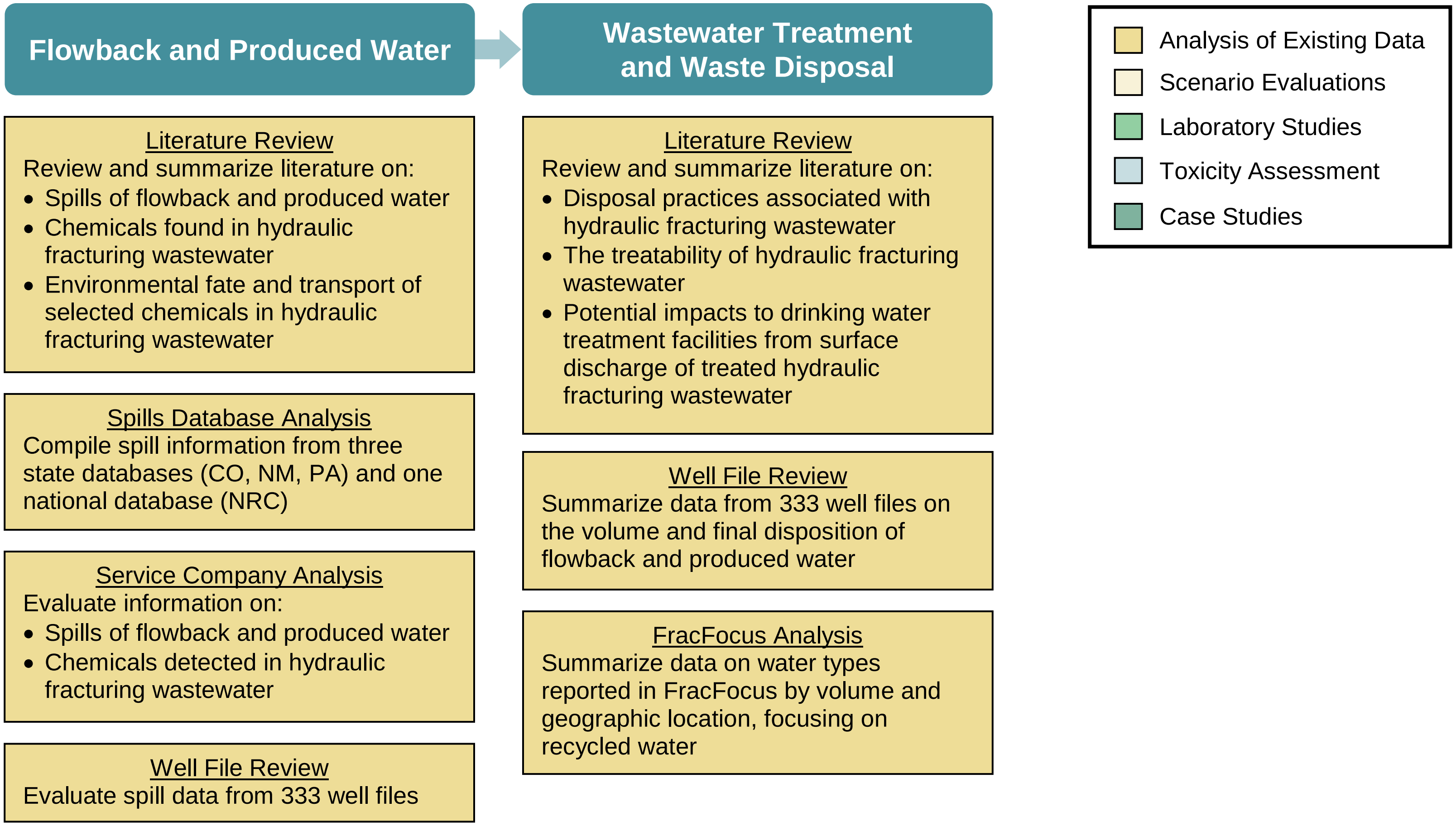

Figure 39a. Summary of research projects underway for the last two stages of the hydraulic fracturing water cycle.

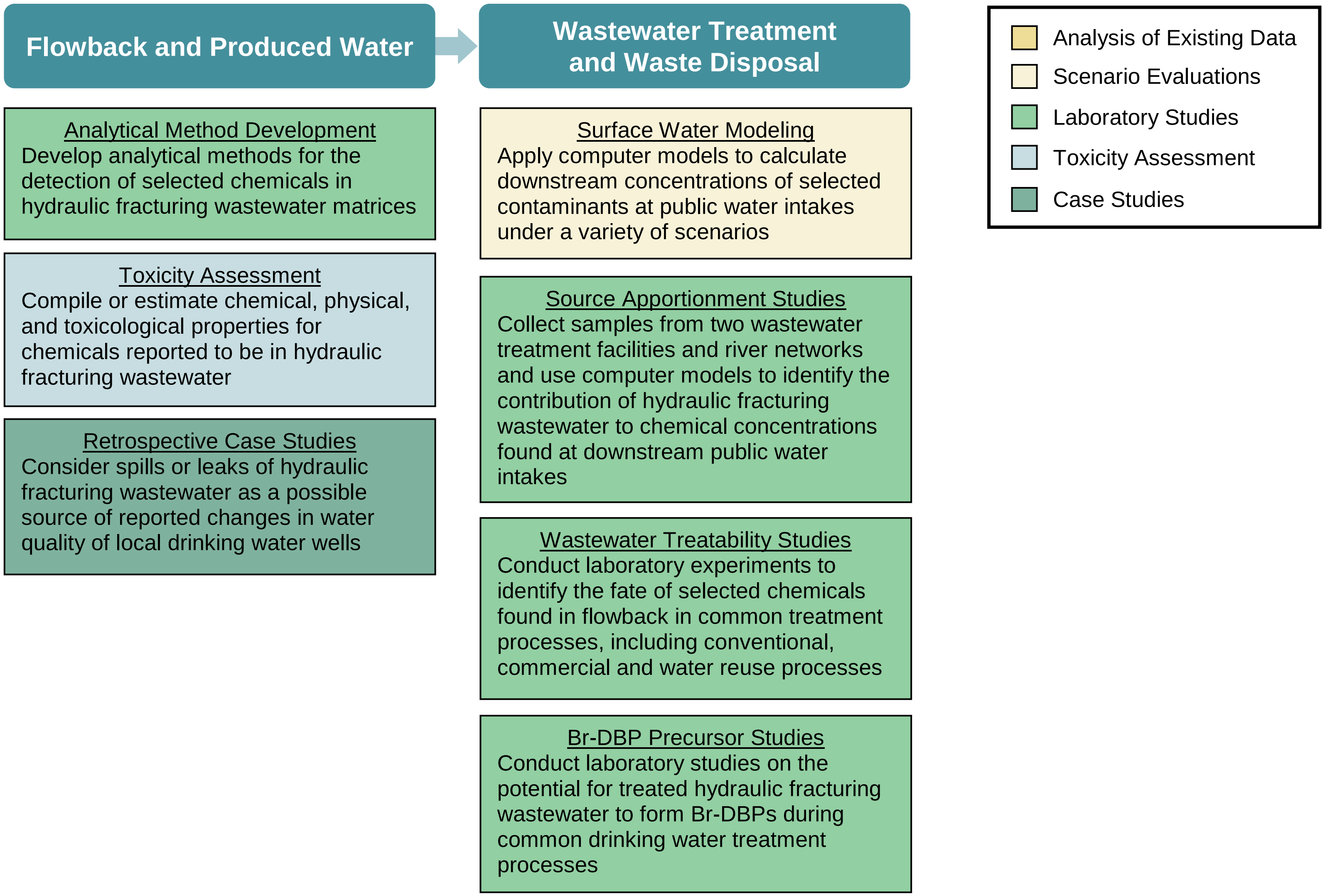

Figure 39b. Summary of research projects underway for the last two stages of the hydraulic fracturing water cycle.

9.3. Report of Results

This is a status report, describing the current progress made on the research projects that make up the agency's S*tudy of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. Results from individual research projects will undergo peer review prior to publication either as articles in scientific journals or EPA reports. The EPA plans to synthesize results from the published reports with a critical literature review in a report of results that will answer as completely as possible the research questions identified in the Study Plan. The report of results has been determined to be a Highly Influential Scientific Assessment and will undergo peer review by the Science Advisory Board. Ultimately, the results of this study are expected to inform the public and provide policymakers at all levels with high-quality scientific knowledge that can be used in decision-making processes.

The report of results will also be informed by information provided through the ongoing stakeholder engagement process described in Section 1.1. This process is anticipated to provide agency scientists with updates on changes in industry practices and technologies relevant to the study. While the EPA expects hydraulic fracturing technology to develop between now and the publication of the report of results, the agency believes that the research described here will provide timely information that will contribute to the state of knowledge on the relationship between hydraulic fracturing and drinking water resources. For example, some companies may adopt new injection or wastewater treatment technologies and practices, while others may continue to use current technologies and practices. Many of the practices, including wastewater treatment and disposal technologies used by POTWs, are not expected to change significantly between now and the report of results.

Results from the study are expected to identify potential impacts to drinking water resources, if any, from water withdrawals, the fate and transport of chemicals associated with hydraulic fracturing, and wastewater treatment and waste disposal. Information on the toxicity of hydraulic fracturing-related chemicals is also being gathered. Although these data may be used to assess the potential risks to drinking water resources from hydraulic fracturing activities, the report of results is not intended to quantify risks. Results presented in the report of results will be appropriately discussed and all uncertainties will be described.

The EPA will strive to make the report of results as clear and definitive as possible in answering all of the primary and secondary research questions, at that time. Science and technology evolve, however: the agency does not believe that the report of results will provide definitive answers on all research questions for all time and fully expects that additional research needs will be identified.

9.4. Conclusions

This report presents the EPA's progress in conducting its *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. Chapters 3 through 7 provide individual progress reports for each of the research projects that make up this study. Each project progress report describes the project's relationship to the study, research methods, and status and summarizes QA activities. Information presented as part of this report cannot be used to draw conclusions about potential impacts to drinking water resources from hydraulic fracturing.

The EPA is committed to conducting a study that uses the best available science, independent sources of information, and a transparent, peer-reviewed process that ensures the validity and accuracy of the results. The EPA will seek input from individual members of an *ad hoc* expert panel convened under the auspices of the EPA's Science Advisory Board. Information about this process is available at http://yosemite.epa.gov/sab/sabproduct.nsf/02ad90b136fc21ef85256eba00436459/b436304ba804e3f885257a5b00521b3b!OpenDocument. The individual members of the *ad hoc* panel will consider public comment. The EPA will consider feedback from the individual experts, as informed by the public's comments, in the development of the report of results.

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Appendix A: Chemicals Identified in Hydraulic Fracturing Fluids and Wastewater

This appendix contains tables of chemicals reported to be used in hydraulic fracturing fluids and chemicals detected in flowback and produced water. Sources of information include federal and state government documents, industry-provided data, and other reliable sources based on the availability of clear scientific methodology and verifiable original sources; the full list of information sources is available in Section A.1. The EPA at this time has not made any judgment about the extent of exposure to these chemicals when used in hydraulic fracturing fluids or found in hydraulic fracturing wastewater, or their potential impacts on drinking water resources.

The tables in this appendix include information provided by nine hydraulic fracturing service companies (see Section 3.3), nine oil and gas operators (Section 3.4), and FracFocus (Section 3.5). Over 150 entries in Tables A-1 and A-2 were provided by the service companies, and roughly 60 entries were provided by FracFocus; these entries were not included in easily obtained public sources. The nine oil and gas operators provided data on chemicals and properties of flowback and produced water; the chemicals and properties are listed in Tables A-3 and A-4.

Much of the information provided in response to the EPA's September 2010 information request to the nine hydraulic fracturing service companies was claimed as confidential business information (CBI) under the Toxic Substances Control Act. In many cases, the service companies have agreed to publicly release chemical names and Chemical Abstract Services Registration Numbers (CASRNs) in Table A-1. However, 82 chemicals with known chemical names and CASRNs continue to be claimed as CBI, and are not included in this appendix. In some instances, generic chemical names have been provided for these chemicals in Table A-2.

In order to standardize chemical names, chemical name and structure annotation quality control methods have been applied to chemicals with CASRNs.[88] These methods ensure correct chemical names and CASRNs and include combining duplicates where appropriate.

The EPA is creating a Distributed Structure-Searchable Toxicity (DSSTox)[89] chemical inventory for chemicals reported to be used in hydraulic fracturing fluids and/or detected in flowback and produced water. The hydraulic fracturing DSSTox chemical inventory will contain CASRNs, chemical names and synonyms, and structure data files (where available). The structure data files can be used with existing computer software to calculate physicochemical properties, as described in Chapter 6.

[88] Additional information on this process can be found at http://www.epa.gov/ncct/dsstox/ChemicalInfQAProcedures.html.

[89] The DSSTox website provides a public forum for publishing downloadable, structure-searchable, standardized chemical structure files associated with chemical inventories or toxicity datasets of environmental relevance. For more information, see http://www.epa.gov/ncct/dsstox/.

Table A-1 lists chemicals reported to be used in hydraulic fracturing fluids between 2005 and 2011. This table lists chemicals with their associated CASRNs. Structure data files are expected to be in the hydraulic fracturing DSSTox chemical inventory for some chemicals on Table A-1; these chemicals are marked with a "✓" in the "IUPAC Name and Structure" column.

Table A-1. List of CASRNs and names of chemicals reportedly used in hydraulic fracturing fluids. Chemical structures and IUPAC names have been identified for the chemicals with an "✓" in the "IUPAC Name and Structure" column. A few chemicals have structures, but no assigned CASRNs; these chemicals have "NA" entered in the CASRN column.

CASRN	Chemical Name	IUPAC Name and Structure	Reference
120086-58-0	(13Z)-N,N-bis(2-hydroxyethyl)-N-methyldocos-13-en-1-aminium chloride	✓	1
123-73-9	(E)-Crotonaldehyde	✓	1, 4
2235-43-0	[Nitrilotris(methylene)]tris-phosphonic acid pentasodium salt	✓	1
65322-65-8	1-(1-Naphthylmethyl)quinolinium chloride	✓	1
68155-37-3	1-(Alkyl* amino)-3-aminopropane *(42%C12, 26%C18, 15%C14, 8%C16, 5%C10, 4%C8)	✓	8
68909-18-2	1-(Phenylmethyl)pyridinium Et Me derivs., chlorides	✓	1, 2, 3, 4, 6, 8
526-73-8	1,2,3-Trimethylbenzene	✓	1, 4
95-63-6	1,2,4-Trimethylbenzene	✓	1, 2, 3, 4, 5
2634-33-5	1,2-Benzisothiazolin-3-one	✓	1, 3, 4
35691-65-7	1,2-Dibromo-2,4-dicyanobutane	✓	1, 4
95-47-6	1,2-Dimethylbenzene	✓	4
138879-94-4	1,2-Ethanediaminium, N, N'-bis[2-[bis(2-hydroxyethyl)methylammonio]ethyl]-N,N'bis(2-hydroxyethyl)-N,N'-dimethyl-,tetrachloride	✓	1, 4
57-55-6	1,2-Propanediol	✓	1, 2, 3, 4, 8
75-56-9	1,2-Propylene oxide	✓	1, 4
4719-04-4	1,3,5-Triazine-1,3,5(2H,4H,6H)-triethanol	✓	1, 4
108-67-8	1,3,5-Trimethylbenzene	✓	1, 4
123-91-1	1,4-Dioxane	✓	2, 3, 4
9051-89-2	1,4-Dioxane-2,5-dione, 3,6-dimethyl-, (3R,6R)-, polymer with (3S,6S)-3,6-dimethyl-1,4-dioxane-2,5-dione and (3R,6S)-rel-3,6-dimethyl-1,4-dioxane-2,5-dione	✓	1, 4, 8
124-09-4	1,6-Hexanediamine	✓	1, 2
6055-52-3	1,6-Hexanediamine dihydrochloride	✓	1
20324-33-8	1-[2-(2-Methoxy-1-methylethoxy)-1-methylethoxy]-2-propanol	✓	4
78-96-6	1-Amino-2-propanol	✓	8

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
15619-48-4	1-Benzylquinolinium chloride	✓	1, 3, 4
71-36-3	1-Butanol	✓	1, 2, 3, 4, 7
112-30-1	1-Decanol	✓	1, 4
2687-96-9	1-Dodecyl-2-pyrrolidinone	✓	1, 4
3452-07-1	1-Eicosene	✓	3
629-73-2	1-Hexadecene	✓	3
111-27-3	1-Hexanol	✓	1, 4, 8
68909-68-7	1-Hexanol, 2-ethyl-, manuf. of, by products from, distn. residues		4
68442-97-7	1H-Imidazole-1-ethanamine, 4,5-dihydro-, 2-nortall-oil alkyl derivs.		2, 4
107-98-2	1-Methoxy-2-propanol	✓	1, 2, 3, 4
2190-04-7	1-Octadecanamine, acetate (1:1)	✓	8
124-28-7	1-Octadecanamine, N,N-dimethyl-	✓	1, 3, 4
112-88-9	1-Octadecene	✓	3
111-87-5	1-Octanol	✓	1, 4
71-41-0	1-Pentanol	✓	8
61789-39-7	1-Propanaminium, 3-amino-N-(carboxymethyl)-N,N-dimethyl-, N-coco acyl derivs., chlorides, sodium salts		1
61789-40-0	1-Propanaminium, 3-amino-N-(carboxymethyl)-N,N-dimethyl-, N-coco acyl derivs., inner salts		1, 2, 3, 4
68139-30-0	1-Propanaminium, N-(3-aminopropyl)-2-hydroxy-N,N-dimethyl-3-sulfo-, N-coco acyl derivs., inner salts		1, 3, 4
149879-98-1	1-Propanaminium, N-(carboxymethyl)-N,N-dimethyl-3-[[(13Z)-1-oxo-13-docosen-1-yl]amino]-,	✓	1, 3
5284-66-2	1-Propanesulfonic acid	✓	3
71-23-8	1-Propanol	✓	1, 2, 4, 5
23519-77-9	1-Propanol, zirconium(4+) salt	✓	1, 4, 8
115-07-1	1-Propene	✓	2
1120-36-1	1-Tetradecene	✓	3
112-70-9	1-Tridecanol	✓	1, 4
112-42-5	1-Undecanol	✓	2
112-34-5	2-(2-Butoxyethoxy)ethanol	✓	2, 4
111-90-0	2-(2-Ethoxyethoxy)ethanol	✓	1, 4
112-15-2	2-(2-Ethoxyethoxy)ethyl acetate	✓	1, 4
102-81-8	2-(Dibutylamino)ethanol	✓	1, 4

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
34375-28-5	2-(Hydroxymethylamino)ethanol	✓	1, 4
21564-17-0	2-(Thiocyanomethylthio)benzothiazole	✓	2
27776-21-2	2,2'-(Azobis(1-methylethylidene))bis(4,5-dihydro-1H-imidazole)dihydrochloride	✓	3
10213-78-2	2,2'-(Octadecylimino)diethanol	✓	1
929-59-9	2,2'-[Ethane-1,2-diylbis(oxy)]diethanamine	✓	1, 4
9003-11-6	2,2'-[propane-1,2-diylbis(oxy)]diethanol	✓	1, 3, 4, 8
25085-99-8	2,2'-[propane-2,2-diylbis(4,1-phenyleneoxymethylene)]dioxirane	✓	1, 4, 8
10222-01-2	2,2-Dibromo-3-nitrilopropionamide	✓	1, 2, 3, 4, 6, 7, 8
73003-80-2	2,2-Dibromopropanediamide	✓	3
24634-61-5	2,4-Hexadienoic acid, potassium salt, (2E,4E)-	✓	3
915-67-3	2,7-Naphthalenedisulfonic acid, 3-hydroxy-4-[2-(4-sulfo-1-naphthalenyl) diazenyl] -, sodium salt (1:3)	✓	4
9002-93-1	2-[4-(1,1,3,3-tetramethylbutyl)phenoxy]ethanol	✓	1, 3, 4
NA	2-Acrylamide - 2-propanesulfonic acid and N,N-dimethylacrylamide copolymer	✓	2
NA	2-acrylamido -2-methylpropanesulfonic acid copolymer	✓	2
15214-89-8	2-Acrylamido-2-methyl-1-propanesulfonic acid	✓	1, 3
124-68-5	2-Amino-2-methylpropan-1-ol	✓	8
2002-24-6	2-Aminoethanol hydrochloride	✓	4, 8
52-51-7	2-Bromo-2-nitropropane-1,3-diol	✓	1, 2, 3, 4, 6
1113-55-9	2-Bromo-3-nitrilopropionamide	✓	1, 2, 3, 4, 5
96-29-7	2-Butanone oxime	✓	1
143106-84-7	2-Butanone, 4-[[[(1R,4aS,10aR)-1,2,3,4,4a,9,10,10a-octahydro-1,4a-dimethyl-7-(1-methylethyl)-1-phenanthrenyl]methyl](3-oxo-3-phenylpropyl)amino]-, hydrochloride (1:1)	✓	1, 4
68442-77-3	2-Butenediamide, (2E)-, N,N'-bis[2-(4,5-dihydro-2-nortall-oil alkyl-1H-imidazol-1-yl)ethyl] derivs.		3, 8
111-76-2	2-Butoxyethanol	✓	1, 2, 3, 4, 6, 7, 8
110-80-5	2-Ethoxyethanol	✓	6
104-76-7	2-Ethyl-1-hexanol	✓	1, 2, 3, 4, 5
645-62-5	2-Ethyl-2-hexenal	✓	2
5444-75-7	2-Ethylhexyl benzoate	✓	4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
818-61-1	2-Hydroxyethyl acrylate	✓	1, 4
13427-63-9	2-Hydroxyethylammonium hydrogen sulphite	✓	1
60-24-2	2-Mercaptoethanol	✓	1, 4
109-86-4	2-Methoxyethanol	✓	4
78-83-1	2-Methyl-1-propanol	✓	1, 2, 4
107-41-5	2-Methyl-2,4-pentanediol	✓	1, 2, 4
2682-20-4	2-Methyl-3(2H)-isothiazolone	✓	1, 2, 4
115-19-5	2-Methyl-3-butyn-2-ol	✓	3
78-78-4	2-Methylbutane	✓	2
62763-89-7	2-Methylquinoline hydrochloride	✓	3
37971-36-1	2-Phosphono-1,2,4-butanetricarboxylic acid	✓	1, 4
93858-78-7	2-Phosphonobutane-1,2,4-tricarboxylic acid, potassium salt (1:x)	✓	1
555-31-7	2-Propanol, aluminum salt	✓	1
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-, chloride, homopolymer	✓	3
13533-05-6	2-Propenoic acid, 2-(2-hydroxyethoxy)ethyl ester	✓	4
113221-69-5	2-Propenoic acid, ethyl ester, polymer with ethenyl acetate and 2,5-furandione, hydrolyzed	✓	4, 8
111560-38-4	2-Propenoic acid, ethyl ester, polymer with ethenyl acetate and 2,5-furandione, hydrolyzed, sodium salt	✓	8
9003-04-7	2-Propenoic acid, homopolymer, sodium salt	✓	1, 2, 3, 4
9003-06-9	2-Propenoic acid, polymer with 2-propenamide	✓	4, 8
25987-30-8	2-Propenoic acid, polymer with 2-propenamide, sodium salt		3, 4, 8
37350-42-8	2-Propenoic acid, sodium salt (1:1), polymer with sodium 2-methyl-2-((1-oxo-2-propen-1-yl)amino)-1-propanesulfonate (1:1)	✓	1
151006-66-5	2-Propenoic acid, telomer with sodium 4-ethenylbenzenesulfonate (1:1), sodium 2-methyl-2-[(1-oxo-2-propen-1-yl)amino]-1-propanesulfonate (1:1) and sodium sulfite (1:1), sodium salt		4
71050-62-9	2-Propenoic, polymer with sodium phosphinate	✓	3, 4
75673-43-7	3,4,4-Trimethyloxazolidine	✓	8
51229-78-8	3,5,7-Triazatricyclo(3.3.1.1(superscript 3,7))decane, 1-(3-chloro-2-propenyl)-, chloride, (Z)-	✓	3
5392-40-5	3,7-Dimethyl-2,6-octadienal	✓	3

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
104-55-2	3-Phenylprop-2-enal	✓	1, 2, 3, 4, 7
12068-08-5	4-(Dodecan-6-yl)benzenesulfonic acid – morpholine (1:1)	✓	1, 4
51200-87-4	4,4-Dimethyloxazolidine	✓	8
5877-42-9	4-Ethyloct-1-yn-3-ol	✓	1, 2, 3, 4
121-33-5	4-Hydroxy-3-methoxybenzaldehyde	✓	3
122-91-8	4-Methoxybenzyl formate	✓	3
150-76-5	4-Methoxyphenol	✓	4
108-11-2	4-Methyl-2-pentanol	✓	1, 4
108-10-1	4-Methyl-2-pentanone	✓	5
104-40-5	4-Nonylphenol	✓	8
26172-55-4	5-Chloro-2-methyl-3(2H)-isothiazolone	✓	1, 2, 4
106-22-9	6-Octen-1-ol, 3,7-dimethyl-	✓	3
75-07-0	Acetaldehyde	✓	1, 4
64-19-7	Acetic acid	✓	1, 2, 3, 4, 5, 6, 7, 8
25213-24-5	Acetic acid ethenyl ester, polymer with ethenol		1, 4
90438-79-2	Acetic acid, C6-8-branched alkyl esters	✓	4
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine	✓	3
5421-46-5	Acetic acid, mercapto-, monoammonium salt	✓	2, 8
108-24-7	Acetic anhydride	✓	1, 2, 3, 4, 7
67-64-1	Acetone	✓	1, 3, 4, 6
7327-60-8	Acetonitrile, 2,2',2''-nitrilotris-	✓	1, 4
98-86-2	Acetophenone	✓	1
77-89-4	Acetyltriethyl citrate	✓	1, 4
107-02-8	Acrolein	✓	2
79-06-1	Acrylamide	✓	1, 2, 3, 4
25085-02-3	Acrylamide/ sodium acrylate copolymer	✓	1, 2, 3, 4, 8
38193-60-1	Acrylamide-sodium-2-acrylamido-2-methlypropane sulfonate copolymer	✓	1, 2, 3, 4
79-10-7	Acrylic acid	✓	2, 4
110224-99-2	Acrylic acid, with sodium-2-acrylamido-2-methyl-1-propanesulfonate and sodium phosphinate	✓	8
67254-71-1	Alcohols, C10-12, ethoxylated	✓	3
68526-86-3	Alcohols, C11-14-iso-, C13-rich	✓	3

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
228414-35-5	Alcohols, C11-14-iso-, C13-rich, butoxylated ethoxylated		1
78330-21-9	Alcohols, C11-14-iso-, C13-rich, ethoxylated	✓	3, 4, 8
126950-60-5	Alcohols, C12-14-secondary	✓	1, 3, 4
84133-50-6	Alcohols, C12-14-secondary, ethoxylated		3, 4, 8
78330-19-5	Alcohols, C7-9-iso-, C8-rich, ethoxylated	✓	2, 4, 8
68603-25-8	Alcohols, C8-10, ethoxylated propoxylated		3
78330-20-8	Alcohols, C9-11-iso-, C10-rich, ethoxylated	✓	1, 2, 4, 8
93924-07-3	Alkanes, C10-14	✓	1
90622-52-9	Alkanes, C10-16-branched and linear		4
68551-19-9	Alkanes, C12-14-iso-	✓	2, 4, 8
68551-20-2	Alkanes, C13-16-iso-	✓	1, 4
64743-02-8	Alkenes, C>10 .alpha.-	✓	1, 3, 4, 8
68411-00-7	Alkenes, C>8		1
68607-07-8	Alkenes, C24-25 alpha-, polymers with maleic anhydride, docosyl esters	✓	8
71011-24-0	Alkyl quaternary ammonium with bentonite		4
85409-23-0	Alkyl* dimethyl ethylbenzyl ammonium chloride *(50%C12, 30%C14, 17%C16, 3%C18)	✓	8
42615-29-2	Alkylbenzenesulfonate, linear	✓	1, 4, 6
1302-62-1	Almandite and pyrope garnet		1, 4
60828-78-6	alpha-[3.5-dimethyl-1-(2-methylpropyl)hexyl]-omega-hydroxy-poly(oxy-1,2-ethandiyl)	✓	3
9000-90-2	alpha-Amylase		4
98-55-5	Alpha-Terpineol	✓	3
1302-42-7	Aluminate (AlO_2^{1-}), sodium	✓	2, 4
7429-90-5	Aluminum	✓	1, 4, 6
12042-68-1	Aluminum calcium oxide (Al_2CaO_4)		2
7446-70-0	Aluminum chloride	✓	1, 4
1327-41-9	Aluminum chloride, basic	✓	3, 4
1344-28-1	Aluminum oxide	✓	1, 2, 4
12068-56-3	Aluminum oxide silicate	✓	1, 2, 4
12141-46-7	Aluminum silicate	✓	1, 2, 4
10043-01-3	Aluminum sulfate	✓	1, 4
68155-07-7	Amides, C8-18 and C18-unsatd., N,N-bis(hydroxyethyl)		3
68140-01-2	Amides, coco, N-[3-(dimethylamino)propyl]		1, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
70851-07-9	Amides, coco, N-[3-(dimethylamino)propyl], alkylation products with chloroacetic acid, sodium salts		1, 4
68155-09-9	Amides, coco, N-[3-(dimethylamino)propyl], N-oxides		1, 3, 4
68876-82-4	Amides, from C16-22 fatty acids and diethylenetriamine		3
68155-20-4	Amides, tall-oil fatty, N,N-bis(hydroxyethyl)		3, 4
68647-77-8	Amides, tallow, N-[3-(dimethylamino)propyl],N-oxides		1, 4
68155-39-5	Amines, C14-18; C16-18-unsaturated, alkyl, ethoxylated		1
68037-94-5	Amines, C8-18 and C18-unsatd. alkyl		5
61788-46-3	Amines, coco alkyl		4
61790-57-6	Amines, coco alkyl, acetates		1, 4
61788-93-0	Amines, coco alkyldimethyl		8
61790-59-8	Amines, hydrogenated tallow alkyl, acetates		4
68966-36-9	Amines, polyethylenepoly-, ethoxylated, phosphonomethylated		1, 4
68603-67-8	Amines, polyethylenepoly-, reaction products with benzyl chloride	✓	1
61790-33-8	Amines, tallow alkyl		8
61791-26-2	Amines, tallow alkyl, ethoxylated		1, 3
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates (salts)		1, 3, 4
68308-48-5	Amines, tallow alkyl, ethoxylated, phosphates		4
6419-19-8	Aminotrimethylene phosphonic acid	✓	1, 4, 8
7664-41-7	Ammonia	✓	1, 2, 3, 4, 7
32612-48-9	Ammonium (lauryloxypolyethoxy)ethyl sulfate	✓	4
631-61-8	Ammonium acetate	✓	1, 3, 4, 5, 8
10604-69-0	Ammonium acrylate	✓	8
26100-47-0	Ammonium acrylate-acrylamide polymer	✓	2, 4, 8
7803-63-6	Ammonium bisulfate	✓	2
10192-30-0	Ammonium bisulfite	✓	1, 2, 3, 4, 7
12125-02-9	Ammonium chloride	✓	1, 2, 3, 4, 5, 6, 8
7632-50-0	Ammonium citrate (1:1)	✓	3
3012-65-5	Ammonium citrate (2:1)	✓	8
2235-54-3	Ammonium dodecyl sulfate	✓	1
12125-01-8	Ammonium fluoride	✓	1, 4
1066-33-7	Ammonium hydrogen carbonate	✓	1, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
1341-49-7	Ammonium hydrogen difluoride	✓	1, 3, 4, 7
13446-12-3	Ammonium hydrogen phosphonate	✓	4
1336-21-6	Ammonium hydroxide	✓	1, 3, 4
8061-53-8	Ammonium ligninsulfonate		2
6484-52-2	Ammonium nitrate	✓	1, 2, 3
7722-76-1	Ammonium phosphate	✓	1, 4
7783-20-2	Ammonium sulfate	✓	1, 2, 3, 4, 6
99439-28-8	Amorphous silica	✓	1, 7
104-46-1	Anethole	✓	3
62-53-3	Aniline	✓	2, 4
1314-60-9	Antimony pentoxide	✓	1, 4
10025-91-9	Antimony trichloride	✓	1, 4
1309-64-4	Antimony trioxide	✓	8
7440-38-2	Arsenic		4
68131-74-8	Ashes, residues		4
68201-32-1	Asphalt, sulfonated, sodium salt		2
12174-11-7	Attapulgite		2, 3
31974-35-3	Aziridine, polymer with 2-methyloxirane	✓	4, 8
7727-43-7	Barium sulfate	✓	1, 2, 4
1318-16-7	Bauxite		1, 2, 4
1302-78-9	Bentonite		1, 2, 4, 6
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex		3, 4
80-08-0	Benzamine, 4,4'-sulfonylbis-	✓	1, 4
71-43-2	Benzene	✓	1, 3, 4
98-82-8	Benzene, (1-methylethyl)-		1, 2, 3, 4
119345-03-8	Benzene, 1,1'-oxybis-, tetrapropylene derivs., sulfonated		8
119345-04-9	Benzene, 1,1'-oxybis-, tetrapropylene derivs., sulfonated, sodium salts		3, 4, 8
611-14-3	Benzene, 1-ethyl-2-methyl-	✓	4
68648-87-3	Benzene, C10-16-alkyl derivs.	✓	1
9003-55-8	Benzene, ethenyl-, polymer with 1,3-butadiene	✓	2, 4
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-(2-((1-oxo-2-propen-1-yl)oxy)ethyl)-, chloride (1:1), polymer with 2-propenamide	✓	3
98-11-3	Benzenesulfonic acid	✓	2

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
37953-05-2	Benzenesulfonic acid, (1-methylethyl)-,	✓	4
37475-88-0	Benzenesulfonic acid, (1-methylethyl)-, ammonium salt	✓	3, 4
28348-53-0	Benzenesulfonic acid, (1-methylethyl)-, sodium salt	✓	8
68584-22-5	Benzenesulfonic acid, C10-16-alkyl derivs.	✓	1, 4
255043-08-4	Benzenesulfonic acid, C10-16-alkyl derivs., compds. with cyclohexylamine	✓	1
68584-27-0	Benzenesulfonic acid, C10-16-alkyl derivs., potassium salts	✓	1, 4, 8
90218-35-2	Benzenesulfonic acid, dodecyl-, branched, compds. with 2-propanamine	✓	4
26264-06-2	Benzenesulfonic acid, dodecyl-, calcium salt	✓	4
68648-81-7	Benzenesulfonic acid, mono-C10-16 alkyl derivs., compds. with 2-propanamine	✓	1, 4
65-85-0	Benzoic acid	✓	1, 4, 7
100-44-7	Benzyl chloride	✓	1, 2, 4, 8
139-07-1	Benzyldimethyldodecylammonium chloride	✓	2, 8
122-18-9	Benzylhexadecyldimethylammonium chloride	✓	8
68425-61-6	Bis(1-methylethyl)naphthalenesulfonic acid, cyclohexylamine salt	✓	1
111-44-4	Bis(2-chloroethyl) ether	✓	8
80-05-7	Bisphenol A	✓	4
65996-69-2	Blast furnace slag		2, 3
1303-96-4	Borax	✓	1, 2, 3, 4, 6
10043-35-3	Boric acid	✓	1, 2, 3, 4, 6, 7
1303-86-2	Boric oxide	✓	1, 2, 3, 4
11128-29-3	Boron potassium oxide		1
1330-43-4	Boron sodium oxide	✓	1, 2, 4
12179-04-3	Boron sodium oxide pentahydrate	✓	8
106-97-8	Butane	✓	2, 5
2373-38-8	Butanedioic acid, sulfo-, 1,4-bis(1,3-dimethylbutyl) ester, sodium salt	✓	1
2673-22-5	Butanedioic acid, sulfo-, 1,4-ditridecyl ester, sodium salt	✓	4
2426-08-6	Butyl glycidyl ether	✓	1, 4
138-22-7	Butyl lactate	✓	1, 4
3734-67-6	C.I. Acid red 1	✓	4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
6625-46-3	C.I. Acid violet 12, disodium salt	✓	4
6410-41-9	C.I. Pigment Red 5	✓	4
4477-79-6	C.I. Solvent Red 26	✓	4
70592-80-2	C10-16-Alkyldimethylamines oxides	✓	4
68002-97-1	C10-C16 ethoxylated alcohol	✓	1, 2, 3, 4, 8
68131-40-8	C11-15-Secondary alcohols ethoxylated	✓	1, 2, 8
73138-27-9	C12-14 tert-alkyl ethoxylated amines	✓	3
66402-68-4	Calcined bauxite		2, 8
12042-78-3	Calcium aluminate	✓	2
7789-41-5	Calcium bromide	✓	4
10043-52-4	Calcium chloride	✓	1, 2, 3, 4, 7
10035-04-8	Calcium dichloride dihydrate	✓	1, 4
7789-75-5	Calcium fluoride	✓	1, 4
1305-62-0	Calcium hydroxide	✓	1, 2, 3, 4
7778-54-3	Calcium hypochlorite	✓	1, 2, 4
58398-71-3	Calcium magnesium hydroxide oxide		4
1305-78-8	Calcium oxide	✓	1, 2, 4, 7
1305-79-9	Calcium peroxide	✓	1, 3, 4, 8
7778-18-9	Calcium sulfate	✓	1, 2, 4
10101-41-4	Calcium sulfate dihydrate	✓	2
76-22-2	Camphor	✓	3
1333-86-4	Carbon black	✓	1, 2, 4
124-38-9	Carbon dioxide	✓	1, 3, 4, 6
471-34-1	Carbonic acid calcium salt (1:1)	✓	1, 2, 4
584-08-7	Carbonic acid, dipotassium salt	✓	1, 2, 3, 4, 8
39346-76-4	Carboxymethyl guar gum, sodium salt		1, 2, 4
61791-12-6	Castor oil, ethoxylated		1, 3
8000-27-9	Cedarwood oil		3
9005-81-6	Cellophane		1, 4
9012-54-8	Cellulase		1, 2, 3, 4, 5
9004-34-6	Cellulose	✓	1, 2, 3, 4
9004-32-4	Cellulose, carboxymethyl ether, sodium salt		2, 3, 4
16887-00-6	Chloride	✓	4, 8
7782-50-5	Chlorine	✓	2

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
10049-04-4	Chlorine dioxide	✓	1, 2, 3, 4, 8
78-73-9	Choline bicarbonate	✓	3, 8
67-48-1	Choline chloride	✓	1, 3, 4, 7, 8
16065-83-1	Chromium (III), insoluble salts	✓	2, 6
18540-29-9	Chromium (VI)	✓	6
39430-51-8	Chromium acetate, basic	✓	2
1066-30-4	Chromium(III) acetate	✓	1, 2
77-92-9	Citric acid	✓	1, 2, 3, 4, 7
8000-29-1	Citronella oil		3
94266-47-4	Citrus extract		1, 3, 4, 8
50815-10-6	Coal, granular		1, 2, 4
71-48-7	Cobalt(II) acetate	✓	1, 4
68424-94-2	Coco-betaine		3
68603-42-9	Coconut oil acid/Diethanolamine condensate (2:1)		1
61789-18-2	Coconut trimethylammonium chloride	✓	1, 8
7440-50-8	Copper	✓	1, 4
7758-98-7	Copper sulfate	✓	1, 4, 8
7758-89-6	Copper(I) chloride	✓	1, 4
7681-65-4	Copper(I) iodide	✓	1, 2, 4, 6
7447-39-4	Copper(II) chloride	✓	1, 3, 4
68525-86-0	Corn flour		4
11138-66-2	Corn sugar gum		1, 2, 4
1302-74-5	Corundum (Aluminum oxide)	✓	4, 8
68308-87-2	Cottonseed, flour		2, 4
91-64-5	Coumarin	✓	3
14464-46-1	Cristobalite	✓	1, 2, 4
15468-32-3	Crystalline silica, tridymite	✓	1, 2, 4
10125-13-0	Cupric chloride dihydrate	✓	1, 4, 7
110-82-7	Cyclohexane	✓	1, 7
108-94-1	Cyclohexanone	✓	1, 4
18472-87-2	D&C Red 28	✓	4
533-74-4	Dazomet	✓	1, 2, 3, 4, 7, 8
1120-24-7	Decyldimethylamine	✓	3, 4
7789-20-0	Deuterium oxide	✓	8

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
50-70-4	D-Glucitol	✓	1, 3, 4
526-95-4	D-Gluconic acid	✓	1, 4
3149-68-6	D-Glucopyranoside, methyl	✓	2
50-99-7	D-Glucose	✓	1, 4
117-81-7	Di(2-ethylhexyl) phthalate	✓	1, 4
7727-54-0	Diammonium peroxydisulfate	✓	1, 2, 3, 4, 6, 7, 8
68855-54-9	Diatomaceous earth		2, 4
91053-39-3	Diatomaceous earth, calcined		1, 2, 4
3252-43-5	Dibromoacetonitrile	✓	1, 2, 3, 4, 8
10034-77-2	Dicalcium silicate	✓	1, 2, 4
7173-51-5	Didecyldimethylammonium chloride	✓	1, 2, 4, 8
111-42-2	Diethanolamine	✓	1, 2, 3, 4, 6
25340-17-4	Diethylbenzene	✓	1, 3, 4
111-46-6	Diethylene glycol	✓	1, 2, 3, 4, 7
111-77-3	Diethylene glycol monomethyl ether	✓	1, 2, 4
111-40-0	Diethylenetriamine	✓	1, 2, 4, 5
68647-57-4	Diethylenetriamine reaction product with fatty acid dimers		2
38640-62-9	Diisopropylnaphthalene	✓	3, 4
627-93-0	Dimethyl adipate	✓	8
1119-40-0	Dimethyl glutarate	✓	1, 4
63148-62-9	Dimethyl polysiloxane	✓	1, 2, 4
106-65-0	Dimethyl succinate	✓	8
108-01-0	Dimethylaminoethanol	✓	2, 4
7398-69-8	Dimethyldiallylammonium chloride	✓	3, 4
101-84-8	Diphenyl oxide	✓	3
7758-11-4	Dipotassium monohydrogen phosphate	✓	5
25265-71-8	Dipropylene glycol	✓	1, 3, 4
31291-60-8	Di-sec-butylphenol	✓	1
28519-02-0	Disodium dodecyl(sulphonatophenoxy)benzenesulphonate	✓	1
38011-25-5	Disodium ethylenediaminediacetate	✓	1, 4
6381-92-6	Disodium ethylenediaminetetraacetate dihydrate	✓	1
12008-41-2	Disodium octaborate	✓	4, 8
12280-03-4	Disodium octaborate tetrahydrate	✓	1, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
68477-31-6	Distillates, petroleum, catalytic reformer fractionator residue, low-boiling		1, 4
68333-25-5	Distillates, petroleum, hydrodesulfurized light catalytic cracked		1
64742-80-9	Distillates, petroleum, hydrodesulfurized middle		1
64742-52-5	Distillates, petroleum, hydrotreated heavy naphthenic		1, 2, 3, 4
64742-54-7	Distillates, petroleum, hydrotreated heavy paraffinic		1, 2, 4
64742-47-8	Distillates, petroleum, hydrotreated light		1, 2, 3, 4, 5, 7, 8
64742-53-6	Distillates, petroleum, hydrotreated light naphthenic		1, 2, 8
64742-55-8	Distillates, petroleum, hydrotreated light paraffinic		8
64742-46-7	Distillates, petroleum, hydrotreated middle		1, 2, 3, 4, 8
64741-59-9	Distillates, petroleum, light catalytic cracked		1, 4
64741-77-1	Distillates, petroleum, light hydrocracked		3
64742-65-0	Distillates, petroleum, solvent-dewaxed heavy paraffinic		1
64741-96-4	Distillates, petroleum, solvent-refined heavy naphthenic		1, 4
64742-91-2	Distillates, petroleum, steam-cracked		1, 4
64741-44-2	Distillates, petroleum, straight-run middle		1, 2, 4
64741-86-2	Distillates, petroleum, sweetened middle		1, 4
71011-04-6	Ditallow alkyl ethoxylated amines		3
10326-41-7	D-Lactic acid	✓	1, 4
5989-27-5	D-Limonene	✓	1, 3, 4, 5, 7, 8
577-11-7	Docusate sodium	✓	1
112-40-3	Dodecane	✓	8
123-01-3	Dodecylbenzene	✓	3, 4
27176-87-0	Dodecylbenzene sulfonic acid		2, 3, 4, 8
26836-07-7	Dodecylbenzenesulfonic acid, monoethanolamine salt	✓	1, 4
12276-01-6	EDTA, copper salt	✓	1, 5, 6
37288-54-3	Endo-1,4-.beta.-mannanase.		3, 8
106-89-8	Epichlorohydrin	✓	1, 4, 8
44992-01-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride	✓	3
69418-26-4	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, polymer with 2-propenamide	✓	1, 3, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
26006-22-4	Ethanaminium, N,N,N-trimethyl-2[(2-methyl-1-oxo-2-propen-1-yl0oxy]-, methyl sulfate 91:1), polymer with 2-propenamide		1, 4
27103-90-8	Ethanaminium, N,N,N-trimethyl-2-[(2-methyl-1-oxo-2-propenyl)oxy]-, methyl sulfate, homopolymer	✓	8
74-84-0	Ethane	✓	2, 5
64-17-5	Ethanol	✓	1, 2, 3, 4, 5, 6, 8
68171-29-9	Ethanol, 2,2',2''-nitrilotris-, tris(dihydrogen phosphate) (ester), sodium salt	✓	4
61791-47-7	Ethanol, 2,2'-iminobis-, N-coco alkyl derivs., N-oxides		1
61791-44-4	Ethanol, 2,2'-iminobis-, N-tallow alkyl derivs.		1
68909-77-3	Ethanol, 2,2'-oxybis-, reaction products with ammonia, morpholine derivs. residues		4, 8
68877-16-7	Ethanol, 2,2-oxybis-, reaction products with ammonia, morpholine derivs. residues, acetates (salts)		4
102424-23-7	Ethanol, 2,2-oxybis-, reaction products with ammonia, morpholine derivs. residues, reaction products with sulfur dioxide		4
25446-78-0	Ethanol, 2-[2-[2-(tridecyloxy)ethoxy]ethoxy]-, hydrogen sulfate, sodium salt	✓	1, 4
34411-42-2	Ethanol, 2-amino-, polymer with formaldehyde	✓	4
68649-44-5	Ethanol, 2-amino-, reaction products with ammonia, by-products from, phosphonomethylated		4
141-43-5	Ethanolamine	✓	1, 2, 3, 4, 6
66455-15-0	Ethoxylated C10-14 alcohols	✓	3
66455-14-9	Ethoxylated C12-13 alcohols	✓	4
68439-50-9	Ethoxylated C12-14 alcohols	✓	2, 3, 4, 8
68131-39-5	Ethoxylated C12-15 alcohols	✓	3, 4
68551-12-2	Ethoxylated C12-16 alcohols	✓	3, 4, 8
68951-67-7	Ethoxylated C14-15 alcohols	✓	3, 4, 8
68439-45-2	Ethoxylated C6-12 alcohols	✓	3, 4, 8
68439-46-3	Ethoxylated C9-11 alcohols	✓	3, 4
9002-92-0	Ethoxylated dodecyl alcohol	✓	4
61790-82-7	Ethoxylated hydrogenated tallow alkylamines		4
68439-51-0	Ethoxylated propoxylated C12-14 alcohols	✓	1, 3, 4, 8
52624-57-4	Ethoxylated, propoxylated trimethylolpropane	✓	3
141-78-6	Ethyl acetate	✓	1, 4, 7

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
141-97-9	Ethyl acetoacetate	✓	1, 4
93-89-0	Ethyl benzoate	✓	3
97-64-3	Ethyl lactate	✓	3
118-61-6	Ethyl salicylate	✓	3
100-41-4	Ethylbenzene	✓	1, 2, 3, 4, 7
9004-57-3	Ethylcellulose	✓	2
107-21-1	Ethylene glycol	✓	1, 2, 3, 4, 6, 7, 8
75-21-8	Ethylene oxide	✓	1, 2, 3, 4
107-15-3	Ethylenediamine	✓	2, 4
60-00-4	Ethylenediaminetetraacetic acid	✓	1, 2, 4
64-02-8	Ethylenediaminetetraacetic acid tetrasodium salt	✓	1, 2, 3, 4
67989-88-2	Ethylenediaminetetraacetic acid, diammonium copper salt	✓	4
139-33-3	Ethylenediaminetetraacetic acid, disodium salt	✓	1, 3, 4, 8
74-86-2	Ethyne	✓	7
68604-35-3	Fatty acids, C 8-18 and C18-unsaturated compounds with diethanolamine		3
70321-73-2	Fatty acids, C14-18 and C16-18-unsatd., distn. residues		2
61788-89-4	Fatty acids, C18-unsatd., dimers	✓	2
61791-29-5	Fatty acids, coco, ethoxylated		3
61791-08-0	Fatty acids, coco, reaction products with ethanolamine, ethoxylated		3
61790-90-7	Fatty acids, tall oil, hexa esters with sorbitol, ethoxylated		1, 4
68188-40-9	Fatty acids, tall oil, reaction products with acetophenone, formaldehyde and thiourea		3
61790-12-3	Fatty acids, tall-oil		1, 2, 3, 4
61790-69-0	Fatty acids, tall-oil, reaction products with diethylenetriamine		1, 4
8052-48-0	Fatty acids, tallow, sodium salts		1, 3
68153-72-0	Fatty acids, vegetable-oil, reaction products with diethylenetriamine		3
3844-45-9	FD&C Blue no. 1	✓	1, 4
7705-08-0	Ferric chloride	✓	1, 3, 4
10028-22-5	Ferric sulfate	✓	1, 4
17375-41-6	Ferrous sulfate monohydrate	✓	2

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
65997-17-3	Fiberglass		2, 3, 4
50-00-0	Formaldehyde	✓	1, 2, 3, 4
NA	Formaldehyde amine	✓	8
29316-47-0	Formaldehyde polymer with 4,1,1-(dimethylethyl)phenol and methyloxirane	✓	3
63428-92-2	Formaldehyde polymer with methyl oxirane, 4-nonylphenol and oxirane	✓	4, 8
28906-96-9	Formaldehyde, polymer with 2-(chloromethyl)oxirane and 4,4'-(1-methylethylidene)bis[phenol]	✓	1, 4
30704-64-4	Formaldehyde, polymer with 4-(1,1-dimethylethyl)phenol, 2-methyloxirane and oxirane	✓	1, 2, 4, 8
30846-35-6	Formaldehyde, polymer with 4-nonylphenol and oxirane	✓	1, 4
35297-54-2	Formaldehyde, polymer with ammonia and phenol	✓	1, 4
25085-75-0	Formaldehyde, polymer with bisphenol A	✓	4
70750-07-1	Formaldehyde, polymer with N1-(2-aminoethyl)-1,2-ethanediamine, benzylated	✓	8
55845-06-2	Formaldehyde, polymer with nonylphenol and oxirane	✓	4
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	✓	1, 3
75-12-7	Formamide	✓	1, 2, 3, 4
64-18-6	Formic acid	✓	1, 2, 3, 4, 6, 7
590-29-4	Formic acid, potassium salt	✓	1, 3, 4
68476-30-2	Fuel oil, no. 2		1, 2
68334-30-5	Fuels, diesel		2
68476-34-6	Fuels, diesel, no. 2		2, 4, 8
8031-18-3	Fuller's earth		2
110-17-8	Fumaric acid	✓	1, 2, 3, 4, 6
98-01-1	Furfural	✓	1, 4
98-00-0	Furfuryl alcohol	✓	1, 4
64741-43-1	Gas oils, petroleum, straight-run		1, 4
9000-70-8	Gelatin		1, 4
12002-43-6	Gilsonite		1, 2, 4
133-42-6	Gluconic acid	✓	7
111-30-8	Glutaraldehyde	✓	1, 2, 3, 4, 7
56-81-5	Glycerin, natural	✓	1, 2, 3, 4, 5

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
135-37-5	Glycine, N-(carboxymethyl)-N-(2-hydroxyethyl)-, disodium salt	✓	1
150-25-4	Glycine, N,N-bis(2-hydroxyethyl)-	✓	1, 4
5064-31-3	Glycine, N,N-bis(carboxymethyl)-, trisodium salt	✓	1, 2, 3, 4
139-89-9	Glycine, N-[2-[bis(carboxymethyl)amino]ethyl]-N-(2-hydroxyethyl)-, trisodium salt	✓	1
79-14-1	Glycolic acid	✓	1, 3, 4
2836-32-0	Glycolic acid sodium salt	✓	1, 3, 4
107-22-2	Glyoxal	✓	1, 2, 4
298-12-4	Glyoxylic acid	✓	1
9000-30-0	Guar gum		1, 2, 3, 4, 7, 8
68130-15-4	Guar gum, carboxymethyl 2-hydroxypropyl ether, sodium salt		1, 2, 3, 4, 7
13397-24-5	Gypsum	✓	2, 4
67891-79-6	Heavy aromatic distillate		1, 4
1317-60-8	Hematite		1, 2, 4
9025-56-3	Hemicellulase enzyme concentrate		3, 4
142-82-5	Heptane	✓	1, 2
68526-88-5	Heptene, hydroformylation products, high-boiling		1, 4
57-09-0	Hexadecyltrimethylammonium bromide	✓	1
110-54-3	Hexane	✓	5
124-04-9	Hexanedioic acid	✓	1, 2, 4, 6
1415-93-6	Humic acids, commercial grade		2
68956-56-9	Hydrocarbons, terpene processing by-products		1, 3, 4
7647-01-0	Hydrochloric acid	✓	1, 2, 3, 4, 5, 6, 7, 8
7664-39-3	Hydrogen fluoride	✓	1, 2, 4
7722-84-1	Hydrogen peroxide	✓	1, 3, 4
7783-06-4	Hydrogen sulfide	✓	1, 2
9004-62-0	Hydroxyethylcellulose	✓	1, 2, 3, 4
4719-04-4	Hydroxylamine hydrochloride	✓	1, 3, 4
10039-54-0	Hydroxylamine sulfate (2:1)	✓	4
9004-64-2	Hydroxypropyl cellulose	✓	2, 4
39421-75-5	Hydroxypropyl guar gum		1, 3, 4, 5, 6, 8

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
120-72-9	Indole	✓	2
430439-54-6	Inulin, carboxymethyl ether, sodium salt		1, 4
12030-49-8	Iridium oxide	✓	8
7439-89-6	Iron	✓	2, 4
1317-61-9	Iron oxide (Fe3O4)	✓	4
1332-37-2	Iron(II) oxide	✓	1, 4
7720-78-7	Iron(II) sulfate	✓	2
7782-63-0	Iron(II) sulfate heptahydrate	✓	1, 2, 3, 4
1309-37-1	Iron(III) oxide	✓	1, 2, 4
89-65-6	Isoascorbic acid	✓	1, 3, 4
75-28-5	Isobutane	✓	2
26952-21-6	Isooctanol	✓	1, 4, 5
123-51-3	Isopentyl alcohol	✓	1, 4
67-63-0	Isopropanol	✓	1, 2, 3, 4, 6, 7
42504-46-1	Isopropanolamine dodecylbenzenesulfonate	✓	1, 3, 4
75-31-0	Isopropylamine	✓	1, 4
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline	✓	3
35674-56-7	Isoquinolinium, 2-(phenylmethyl)-, chloride	✓	3
9043-30-5	Isotridecanol, ethoxylated	✓	1, 3, 4, 8
1332-58-7	Kaolin	✓	1, 2, 4
8008-20-6	Kerosine (petroleum)		1, 2, 3, 4, 8
64742-81-0	Kerosine, petroleum, hydrodesulfurized		1, 2, 4
61790-53-2	Kieselguhr	✓	1, 2, 4
1302-76-7	Kyanite		1, 2, 4
50-21-5	Lactic acid	✓	1, 4, 8
63-42-3	Lactose	✓	3
13197-76-7	Lauryl hydroxysultaine	✓	1
8022-15-9	Lavandula hybrida abrial herb oil		3
4511-42-6	L-Dilactide	✓	1, 4
7439-92-1	Lead	✓	1, 4
8002-43-5	Lecithin		4
129521-66-0	Lignite		2
8062-15-5	Lignosulfuric acid		2

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
1317-65-3	Limestone	✓	1, 2, 3, 4
8001-26-1	Linseed oil		8
79-33-4	L-Lactic acid	✓	1, 4, 8
546-93-0	Magnesium carbonate (1:1)	✓	1, 3, 4
7786-30-3	Magnesium chloride	✓	1, 2, 4
7791-18-6	Magnesium chloride hexahydrate	✓	4
1309-42-8	Magnesium hydroxide	✓	1, 4
19086-72-7	Magnesium iron silicate		1, 4
10377-60-3	Magnesium nitrate	✓	1, 2, 4
1309-48-4	Magnesium oxide	✓	1, 2, 3, 4
14452-57-4	Magnesium peroxide	✓	1, 4
12057-74-8	Magnesium phosphide	✓	1
1343-88-0	Magnesium silicate	✓	1, 4
26099-09-2	Maleic acid homopolymer	✓	8
25988-97-0	Methanamine-N-methyl polymer with chloromethyl oxirane	✓	4
74-82-8	Methane	✓	2, 5
67-56-1	Methanol	✓	1, 2, 3, 4, 5, 6, 7, 8
100-97-0	Methenamine	✓	1, 2, 4
625-45-6	Methoxyacetic acid	✓	8
9004-67-5	Methyl cellulose	✓	8
119-36-8	Methyl salicylate	✓	1, 2, 3, 4, 7
78-94-4	Methyl vinyl ketone	✓	1, 4
108-87-2	Methylcyclohexane	✓	1
6317-18-6	Methylene bis(thiocyanate)	✓	2
66204-44-2	Methylenebis(5-methyloxazolidine)	✓	2
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	✓	3
12001-26-2	Mica		1, 2, 4, 6
8012-95-1	Mineral oil - includes paraffin oil		4, 8
64475-85-0	Mineral spirits		2
26038-87-9	Monoethanolamine borate (1:x)	✓	1, 4
1318-93-0	Montmorillonite		2
110-91-8	Morpholine	✓	1, 2, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
78-21-7	Morpholinium, 4-ethyl-4-hexadecyl-, ethyl sulfate	✓	8
1302-93-8	Mullite		1,2, 4, 8
46830-22-2	N-(2-Acryloyloxyethyl)-N-benzyl-N,N-dimethylammonium chloride	✓	3
54076-97-0	N,N,N-Trimethyl-2[1-oxo-2-propenyl]oxy ethanaminimum chloride, homopolymer	✓	3
19277-88-4	N,N,N-Trimethyl-3-((1-oxooctadecyl)amino)-1-propanaminium methyl sulfate	✓	1
112-03-8	N,N,N-Trimethyloctadecan-1-aminium chloride	✓	1, 3, 4
109-46-6	N,N'-Dibutylthiourea	✓	1, 4
2605-79-0	N,N-Dimethyldecylamine oxide	✓	1, 3, 4
68-12-2	N,N-Dimethylformamide	✓	1, 2, 4, 5, 8
593-81-7	N,N-Dimethylmethanamine hydrochloride	✓	1, 4, 5, 7
1184-78-7	N,N-Dimethyl-methanamine-N-oxide	✓	3
1613-17-8	N,N-Dimethyloctadecylamine hydrochloride	✓	1, 4
110-26-9	N,N'-Methylenebisacrylamide	✓	1, 4
64741-68-0	Naphtha, petroleum, heavy catalytic reformed		1, 2, 3, 4
64742-48-9	Naphtha, petroleum, hydrotreated heavy		1, 2, 3, 4, 8
91-20-3	Naphthalene	✓	1, 2, 3, 4, 5, 7
93-18-5	Naphthalene, 2-ethoxy-	✓	3
28757-00-8	Naphthalenesulfonic acid, bis(1-methylethyl)-	✓	1, 3, 4
99811-86-6	Naphthalenesulphonic acid, bis (1-methylethyl)-methyl derivatives	✓	1
68410-62-8	Naphthenic acid ethoxylate	✓	4
7786-81-4	Nickel sulfate	✓	2
10101-97-0	Nickel(II) sulfate hexahydrate	✓	1, 4
61790-29-2	Nitriles, tallow, hydrogenated		4
4862-18-4	Nitrilotriacetamide	✓	1, 4, 7
139-13-9	Nitrilotriacetic acid	✓	1, 4
18662-53-8	Nitrilotriacetic acid trisodium monohydrate	✓	1, 4
7727-37-9	Nitrogen	✓	1, 2, 3, 4, 6
872-50-4	N-Methyl-2-pyrrolidone	✓	1, 4
105-59-9	N-Methyldiethanolamine	✓	2, 4, 8
109-83-1	N-Methylethanolamine	✓	4
68213-98-9	N-Methyl-N-hydroxyethyl-N-hydroxyethoxyethylamine	✓	4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
13127-82-7	N-Oleyl diethanolamide	✓	1, 4
25154-52-3	Nonylphenol (mixed)	✓	1, 4
8000-48-4	Oil of eucalyptus		3
8007-02-1	Oil of lemongrass		3
8000-25-7	Oil of rosemary		3
112-80-1	Oleic acid	✓	2, 4
1317-71-1	Olivine		4
8028-48-6	Orange terpenes		4
68649-29-6	Oxirane, methyl-, polymer with oxirane, mono-C10-16-alkyl ethers, phosphates		1, 4
51838-31-4	Oxiranemethanaminium, N,N,N-trimethyl-, chloride, homopolymer	✓	1, 2, 3, 4, 5, 8
7782-44-7	Oxygen	✓	4
10028-15-6	Ozone	✓	8
8002-74-2	Paraffin waxes and Hydrocarbon waxes		1
30525-89-4	Paraformaldehyde	✓	2
4067-16-7	Pentaethylenehexamine	✓	4
109-66-0	Pentane	✓	2, 5
628-63-7	Pentyl acetate	✓	3
540-18-1	Pentyl butyrate	✓	3
79-21-0	Peracetic acid	✓	8
93763-70-3	Perlite		4
64743-01-7	Petrolatum, petroleum, oxidized		3
8002-05-9	Petroleum		1, 2
6742-47-8	Petroleum distillate hydrotreated light		8
85-01-8	Phenanthrene	✓	6
108-95-2	Phenol	✓	1, 2, 4
25068-38-6	Phenol, 4,4'-(1-methylethylidene)bis-, polymer with 2-(chloromethyl)oxirane	✓	1, 2, 4
9003-35-4	Phenol, polymer with formaldehyde	✓	1, 2, 4, 7
7803-51-2	Phosphine	✓	1, 4
13598-36-2	Phosphonic acid	✓	1, 4
29712-30-9	Phosphonic acid (dimethylamino(methylene))	✓	1
129828-36-0	Phosphonic acid, (((2-[(2-hydroxyethyl)(phosphonomethyl)amino)ethyl)imino]bis(methylene))bis-, compd. with 2-aminoethanol	✓	1

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
67953-76-8	Phosphonic acid, (1-hydroxyethylidene)bis-, potassium salt	✓	4
3794-83-0	Phosphonic acid, (1-hydroxyethylidene)bis-, tetrasodium salt	✓	1, 4
15827-60-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-	✓	1, 2, 4
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt (1:x)	✓	3
22042-96-2	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, sodium salt	✓	3
34690-00-1	Phosphonic acid, [[(phosphonomethyl)imino]bis[6,1-hexanediylnitrilobis(methylene)]]tetrakis-	✓	1, 4, 8
7664-38-2	Phosphoric acid	✓	1, 2, 4
7785-88-8	Phosphoric acid, aluminium sodium salt	✓	1, 2
7783-28-0	Phosphoric acid, diammonium salt	✓	2
68412-60-2	Phosphoric acid, mixed decyl and Et and octyl esters		1
10294-56-1	Phosphorous acid	✓	1
85-44-9	Phthalic anhydride	✓	1, 4
8002-09-3	Pine oils		1, 2, 4
25038-54-4	Policapram (Nylon 6)		1, 4
62649-23-4	Poly (acrylamide-co-acrylic acid), partial sodium salt	✓	3, 4
26680-10-4	Poly(lactide)	✓	1
9014-93-1	Poly(oxy-1,2-ethanediyl), .alpha.-(dinonylphenyl)-. omega.-hydroxy-	✓	4
9016-45-9	Poly(oxy-1,2-ethanediyl), .alpha.-(nonylphenyl)-.omega.-hydroxy-	✓	1, 2, 3, 4, 8
51811-79-1	Poly(oxy-1,2-ethanediyl), .alpha.-(nonylphenyl)-.omega.-hydroxy-, phosphate	✓	1, 4
68987-90-6	Poly(oxy-1,2-ethanediyl), .alpha.-(octylphenyl)-.omega.-hydroxy-, branched	✓	1, 4
26635-93-8	Poly(oxy-1,2-ethanediyl), .alpha.,.alpha.'-[[(9Z)-9-octadecenylimino]di-2,1-ethanediyl]bis[.omega.-hydroxy-	✓	1, 4
9004-96-0	Poly(oxy-1,2-ethanediyl), .alpha.-[(9Z)-1-oxo-9-octadecenyl]-.omega.-hydroxy-	✓	8
68891-38-3	Poly(oxy-1,2-ethanediyl), .alpha.-sulfo-.omega.-hydroxy-, C12-14-alkyl ethers, sodium salts		1, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
61723-83-9	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy-, ether with D-glucitol (2:1), tetra-(9Z)-9-octadecenoate	✓	8
68015-67-8	Poly(oxy-1,2-ethanediyl), alpha-(2,3,4,5-tetramethylnonyl)-omega-hydroxy	✓	1
68412-53-3	Poly(oxy-1,2-ethanediyl), alpha-(nonylphenyl)-omega-hydroxy-,branched, phosphates	✓	1
31726-34-8	Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy		3, 8
56449-46-8	Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy-, (9Z)-9-octadecenoate	✓	3
65545-80-4	Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy-, ether with alpha-fluoro-omega-(2-hydroxyethyl)poly(difluoromethylene) (1:1)		1
27306-78-1	Poly(oxy-1,2-ethanediyl), alpha-methyl-omega-(3-(1,3,3,3-tetramethyl-1-((trimethylsilyl)oxy)-1-disiloxanyl)propoxy)-	✓	1
52286-19-8	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(decyloxy)-, ammonium salt (1:1)	✓	4
63428-86-4	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(hexyloxy)-, ammonium salt (1:1)	✓	1, 3, 4
68037-05-8	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(hexyloxy)-, C6-10-alkyl ethers, ammonium salts	✓	3, 4
9081-17-8	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega--(nonylphenoxy)-	✓	4
52286-18-7	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(octyloxy)-, ammonium salt (1:1)	✓	4
68890-88-0	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-hydroxy-, C10-12-alkyl ethers, ammonium salts	✓	8
24938-91-8	Poly(oxy-1,2-ethanediyl), alpha-tridecyl-omega-hydroxy-	✓	1, 3, 4
127036-24-2	Poly(oxy-1,2-ethanediyl), alpha-undecyl-omega-hydroxy-, branched and linear	✓	1
68412-54-4	Poly(oxy-1,2-ethanediyl),alpha-(4-nonylphenyl)-omega-hydroxy-,branched	✓	2, 3, 4
34398-01-1	Poly-(oxy-1,2-ethanediyl)-alpha-undecyl-omega-hydroxy	✓	1, 3, 4, 8
127087-87-0	Poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy branched	✓	1, 2, 3, 4
25704-18-1	Poly(sodium-p-styrenesulfonate)	✓	1, 4
32131-17-2	Poly[imino(1,6-dioxo-1,6-hexanediyl)imino-1,6-hexanediyl]	✓	2
9003-05-8	Polyacrylamide	✓	1, 2, 4, 6

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
NA	Polyacrylate/ polyacrylamide blend	✓	2
66019-18-9	Polyacrylic acid, sodium bisulfite terminated	✓	3
25322-68-3	Polyethylene glycol	✓	1, 2, 3, 4, 7, 8
9004-98-2	Polyethylene glycol (9Z)-9-octadecenyl ether	✓	8
68187-85-9	Polyethylene glycol ester with tall oil fatty acid		1
9036-19-5	Polyethylene glycol mono(octylphenyl) ether	✓	1, 2, 3, 4, 8
9004-77-7	Polyethylene glycol monobutyl ether	✓	1, 4
68891-29-2	Polyethylene glycol mono-C8-10-alkyl ether sulfate ammonium	✓	1, 3, 4
9046-01-9	Polyethylene glycol tridecyl ether phosphate	✓	1, 3, 4
9002-98-6	Polyethyleneimine		4
25618-55-7	Polyglycerol	✓	2
9005-70-3	Polyoxyethylene sorbitan trioleate	✓	3
26027-38-3	Polyoxyethylene(10)nonylphenyl ether	✓	1, 2, 3, 4, 8
9046-10-0	Polyoxypropylenediamine	✓	1
68131-72-6	Polyphosphoric acids, esters with triethanolamine, sodium salts		1
68915-31-1	Polyphosphoric acids, sodium salts	✓	1, 4
25322-69-4	Polypropylene glycol	✓	1, 2, 4
68683-13-6	Polypropylene glycol glycerol triether, epichlorohydrin, bisphenol A polymer		1
9011-19-2	Polysiloxane		4
9005-64-5	Polysorbate 20	✓	8
9003-20-7	Polyvinyl acetate copolymer	✓	2
9002-89-5	Polyvinyl alcohol	✓	1, 2, 4
NA	Polyvinyl alcohol/polyvinyl acetate copolymer	✓	1
9002-85-1	Polyvinylidene chloride		8
65997-15-1	Portland cement		2, 4
127-08-2	Potassium acetate	✓	1, 3, 4
1327-44-2	Potassium aluminum silicate	✓	5
29638-69-5	Potassium antimonate	✓	1, 4
12712-38-8	Potassium borate	✓	3
20786-60-1	Potassium borate (1:x)	✓	1, 3
6381-79-9	Potassium carbonate sesquihydrate	✓	5

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Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
7447-40-7	Potassium chloride	✓	1, 2, 3, 4, 5, 6, 7
7778-50-9	Potassium dichromate	✓	4
1310-58-3	Potassium hydroxide	✓	1, 2, 3, 4, 6
7681-11-0	Potassium iodide	✓	1, 4
13709-94-9	Potassium metaborate	✓	1, 2, 3, 4, 8
143-18-0	Potassium oleate	✓	4
12136-45-7	Potassium oxide	✓	1, 4
7727-21-1	Potassium persulfate	✓	1, 2, 4
7778-80-5	Potassium sulfate	✓	2
74-98-6	Propane	✓	2, 5
2997-92-4	Propanimidamide,2,2''-aAzobis[(2-methyl-, amidinopropane) dihydrochloride	✓	1, 4
34590-94-8	Propanol, 1(or 2)-(2-methoxymethylethoxy)-	✓	1, 2, 3, 4
107-19-7	Propargyl alcohol	✓	1, 2, 3, 4, 5, 6, 7, 8
108-32-7	Propylene carbonate	✓	1, 4
15220-87-8	Propylene pentamer	✓	1
106-42-3	p-Xylene	✓	1, 4
68391-11-7	Pyridine, alkyl derivs.		1, 4
100765-57-9	Pyridinium, 1-(phenylmethyl)-, alkyl derivs., chlorides		4, 8
70914-44-2	Pyridinium, 1-(phenylmethyl)-, C7-8-alkyl derivs., chlorides	✓	6
289-95-2	Pyrimidine	✓	2
109-97-7	Pyrrole	✓	2
14808-60-7	Quartz	✓	1, 2, 3, 4, 5, 6, 8
308074-31-9	Quaternary ammonium compounds (2-ethylhexyl) hydrogenated tallow alkyl)dimethyl, methyl sulfates		8
68607-28-3	Quaternary ammonium compounds, (oxydi-2,1-ethanediyl)bis[coco alkyldimethyl, dichlorides		2, 3, 4, 8
68153-30-0	Quaternary ammonium compounds, benzylbis(hydrogenated tallow alkyl)methyl, salts with bentonite		2, 5, 6
68989-00-4	Quaternary ammonium compounds, benzyl-C10-16-alkyldimethyl, chlorides	✓	1, 4

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
68424-85-1	Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl, chlorides	✓	1, 2, 4, 8
68391-01-5	Quaternary ammonium compounds, benzyl-C12-18-alkyldimethyl, chlorides	✓	8
61789-68-2	Quaternary ammonium compounds, benzylcoco alkylbis(hydroxyethyl), chlorides		1, 4
68953-58-2	Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with bentonite		2, 3, 4, 8
71011-27-3	Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with hectorite		2
68424-95-3	Quaternary ammonium compounds, di-C8-10-alkyldimethyl, chlorides	✓	2
61789-77-3	Quaternary ammonium compounds, dicoco alkyldimethyl, chlorides		1
68607-29-4	Quaternary ammonium compounds, pentamethyltallow alkyltrimethylenedi-, dichlorides		4
8030-78-2	Quaternary ammonium compounds, trimethyltallow alkyl, chlorides		1, 4
91-22-5	Quinoline	✓	2, 4
68514-29-4	Raffinates (petroleum)		5
64741-85-1	Raffinates, petroleum, sorption process		1, 2, 4, 8
64742-01-4	Residual oils, petroleum, solvent-refined		5
64741-67-9	Residues, petroleum, catalytic reformer fractionator		1, 4, 8
81-88-9	Rhodamine B	✓	4
8050-09-7	Rosin		1, 4
12060-08-1	Scandium oxide	✓	8
63800-37-3	Sepiolite		2
68611-44-9	Silane, dichlorodimethyl-, reaction products with silica		2
7631-86-9	Silica	✓	1, 2, 3, 4, 8
112926-00-8	Silica gel, cryst. -free		3, 4
112945-52-5	Silica, amorphous, fumed, cryst.-free	✓	1, 3, 4
60676-86-0	Silica, vitreous	✓	1, 4, 8
55465-40-2	Silicic acid, aluminum potassium sodium salt		4
68037-74-1	Siloxanes and silicones, di-Me, polymers with Me silsesquioxanes		4
67762-90-7	Siloxanes and Silicones, di-Me, reaction products with silica		4
63148-52-7	Siloxanes and silicones, dimethyl,		4

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
5324-84-5	Sodium 1-octanesulfonate	✓	3
2492-26-4	Sodium 2-mercaptobenzothiolate	✓	2
127-09-3	Sodium acetate	✓	1, 3, 4
532-32-1	Sodium benzoate	✓	3
144-55-8	Sodium bicarbonate	✓	1, 2, 3, 4, 7
7631-90-5	Sodium bisulfite	✓	1, 3, 4
1333-73-9	Sodium borate	✓	1, 4, 6, 7
7789-38-0	Sodium bromate	✓	1, 2, 4
7647-15-6	Sodium bromide	✓	1, 2, 3, 4, 7
1004542-84-0	Sodium bromosulfamate	✓	8
68610-44-6	Sodium caprylamphopropionate	✓	4
497-19-8	Sodium carbonate	✓	1, 2, 3, 4, 8
7775-09-9	Sodium chlorate	✓	1, 4
7647-14-5	Sodium chloride	✓	1, 2, 3, 4, 5, 8
7758-19-2	Sodium chlorite	✓	1, 2, 3, 4, 5, 8
3926-62-3	Sodium chloroacetate	✓	3
68608-68-4	Sodium cocaminopropionate		1
142-87-0	Sodium decyl sulfate	✓	1
527-07-1	Sodium D-gluconate	✓	4
126-96-5	Sodium diacetate	✓	1, 4
2893-78-9	Sodium dichloroisocyanurate	✓	2
151-21-3	Sodium dodecyl sulfate	✓	8
6381-77-7	Sodium erythorbate (1:1)	✓	1, 3, 4, 8
126-92-1	Sodium ethasulfate	✓	1
141-53-7	Sodium formate	✓	2, 8
7681-38-1	Sodium hydrogen sulfate	✓	4
1310-73-2	Sodium hydroxide	✓	1, 2, 3, 4, 7, 8
7681-52-9	Sodium hypochlorite	✓	1, 2, 3, 4, 8
7681-82-5	Sodium iodide	✓	4
8061-51-6	Sodium ligninsulfonate		2
18016-19-8	Sodium maleate (1:x)	✓	8
7681-57-4	Sodium metabisulfite	✓	1

Table continued on next page

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
7775-19-1	Sodium metaborate	✓	3, 4
16800-11-6	Sodium metaborate dihydrate	✓	1, 4
10555-76-7	Sodium metaborate tetrahydrate	✓	1, 4, 8
6834-92-0	Sodium metasilicate	✓	1, 2, 4
7631-99-4	Sodium nitrate	✓	2
7632-00-0	Sodium nitrite	✓	1, 2, 4
137-20-2	Sodium N-methyl-N-oleoyltaurate	✓	4
142-31-4	Sodium octyl sulfate	✓	1
1313-59-3	Sodium oxide	✓	1
11138-47-9	Sodium perborate	✓	4
10486-00-7	Sodium perborate tetrahydrate	✓	1, 4, 5, 8
7632-04-4	Sodium peroxoborate	✓	1
7775-27-1	Sodium persulfate	✓	1, 2, 3, 4, 7, 8
7632-05-5	Sodium phosphate	✓	1, 4
9084-06-4	Sodium polynaphthalenesulfonate	✓	2
7758-16-9	Sodium pyrophosphate	✓	1, 2, 4
54-21-7	Sodium salicylate	✓	1, 4
533-96-0	Sodium sesquicarbonate	✓	1, 2
1344-09-8	Sodium silicate	✓	1, 2, 4
9063-38-1	Sodium starch glycolate		2
7757-82-6	Sodium sulfate	✓	1, 2, 3, 4
7757-83-7	Sodium sulfite	✓	2, 4, 8
540-72-7	Sodium thiocyanate	✓	1, 4
7772-98-7	Sodium thiosulfate	✓	1, 2, 3, 4
10102-17-7	Sodium thiosulfate, pentahydrate	✓	1, 4
650-51-1	Sodium trichloroacetate	✓	1, 4
1300-72-7	Sodium xylenesulfonate	✓	1, 3, 4
10377-98-7	Sodium zirconium lactate	✓	1, 4
64742-88-7	Solvent naphtha (petroleum), medium aliph.		1, 2, 4
64742-96-7	Solvent naphtha, petroleum, heavy aliph.		2, 8
64742-94-5	Solvent naphtha, petroleum, heavy arom.		1, 2, 4, 5, 8
64742-95-6	Solvent naphtha, petroleum, light arom.		1, 2, 4
8007-43-0	Sorbitan, (9Z)-9-octadecenoate (2:3)	✓	4

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
1338-43-8	Sorbitan, mono-(9Z)-9-octadecenoate	✓	1, 2, 3, 4
9005-65-6	Sorbitan, mono-(9Z)-9-octadecenoate, poly(oxy-1,2-ethanediyl) derivis.	✓	3, 4
9005-67-8	Sorbitan, monooctadecenoate, poly(oxy-1,2-ethanediyl) derivis.	✓	3, 4
26266-58-0	Sorbitan, tri-(9Z)-9-octadecenoate	✓	8
10025-69-1	Stannous chloride dihydrate	✓	1, 4
9005-25-8	Starch		1, 2, 4
68131-87-3	Steam cracked distillate, cyclodiene dimer, dicyclopentadiene polymer		1
8052-41-3	Stoddard solvent		1, 3, 4
10476-85-4	Strontium chloride	✓	4
100-42-5	Styrene	✓	2
57-50-1	Sucrose	✓	1, 2, 3, 4
5329-14-6	Sulfamic acid	✓	1, 4
14808-79-8	Sulfate	✓	1, 4
68201-64-9	Sulfomethylated quebracho		2
68608-21-9	Sulfonic acids, C10-16-alkane, sodium salts	✓	6
68439-57-6	Sulfonic acids, C14-16-alkane hydroxy and C14-16-alkene, sodium salts		1, 3, 4
61789-85-3	Sulfonic acids, petroleum		1
68608-26-4	Sulfonic acids, petroleum, sodium salts		3
7446-09-5	Sulfur dioxide	✓	2, 4, 8
7664-93-9	Sulfuric acid	✓	1, 2, 4, 7
68955-19-1	Sulfuric acid, mono-C12-18-alkyl esters, sodium salts	✓	4
68187-17-7	Sulfuric acid, mono-C6-10-alkyl esters, ammonium salts	✓	1, 4, 8
14807-96-6	Talc		1, 3, 4, 6, 7
8002-26-4	Tall oil		4, 8
61791-36-4	Tall oil imidazoline		4
68092-28-4	Tall oil, compound with diethanolamine		1
65071-95-6	Tall oil, ethoxylated		4, 8
8016-81-7	Tall-oil pitch		4
61790-60-1	Tallow alkyl amines acetate		8
72480-70-7	Tar bases, quinoline derivatives, benzyl chloride-quaternized		1, 3, 4
68647-72-3	Terpenes and Terpenoids, sweet orange-oil		1, 3, 4, 8

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
8000-41-7	Terpineol	✓	1, 3
75-91-2	tert-Butyl hydroperoxide	✓	1, 4
614-45-9	tert-Butyl perbenzoate	✓	1
12068-35-8	Tetra-calcium-alumino-ferrite		1, 2, 4
629-59-4	Tetradecane	✓	8
139-08-2	Tetradecyldimethylbenzylammonium chloride	✓	1, 4, 8
112-60-7	Tetraethylene glycol	✓	1, 4
112-57-2	Tetraethylenepentamine	✓	1, 4
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate	✓	1, 2, 3, 4, 7
681-84-5	Tetramethyl orthosilicate	✓	1
75-57-0	Tetramethylammonium chloride	✓	1, 2, 3, 4, 7, 8
1762-95-4	Thiocyanic acid, ammonium salt	✓	2, 3, 4
68-11-1	Thioglycolic acid	✓	1, 2, 3, 4
62-56-6	Thiourea	✓	1, 2, 3, 4, 6
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone	✓	1, 4, 8
68917-35-1	Thuja plicata donn ex. D. don leaf oil		3
7772-99-8	Tin(II) chloride	✓	1
13463-67-7	Titanium dioxide	✓	1, 2, 4
36673-16-2	Titanium(4+) 2-[bis(2-hydroxyethyl)amino]ethanolate propan-2-olate (1:2:2)	✓	1
74665-17-1	Titanium, iso-Pr alc. triethanolamine complexes	✓	1, 4
108-88-3	Toluene	✓	1, 3, 4
126-73-8	Tributyl phosphate	✓	1, 2, 4
81741-28-8	Tributyltetradecylphosphonium chloride	✓	1, 3, 4
7758-87-4	Tricalcium phosphate	✓	1, 4
12168-85-3	Tricalcium silicate	✓	1, 2, 4
87-90-1	Trichloroisocyanuric acid	✓	2
629-50-5	Tridecane	✓	8
102-71-6	Triethanolamine	✓	1, 2, 4
68299-02-5	Triethanolamine hydroxyacetate	✓	3
68131-71-5	Triethanolamine polyphosphate ester	✓	1, 4, 8
77-93-0	Triethyl citrate	✓	1, 4
78-40-0	Triethyl phosphate	✓	1, 4

Table continued on next page

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CASRN	Chemical Name	IUPAC Name and Structure	Reference
112-27-6	Triethylene glycol	✓	1, 2, 3
112-24-3	Triethylenetetramine	✓	4
122-20-3	Triisopropanolamine	✓	1, 4
14002-32-5	Trimethanolamine	✓	3
121-43-7	Trimethyl borate	✓	8
25551-13-7	Trimethylbenzene	✓	1, 2, 4
7758-29-4	Triphosphoric acid, pentasodium salt	✓	1, 4
1317-95-9	Tripoli	✓	4
6100-05-6	Tripotassium citrate monohydrate	✓	4
25498-49-1	Tripropylene glycol monomethyl ether	✓	2
68-04-2	Trisodium citrate	✓	3
6132-04-3	Trisodium citrate dihydrate	✓	1, 4
150-38-9	Trisodium ethylenediaminetetraacetate	✓	1, 3
19019-43-3	Trisodium ethylenediaminetriacetate	✓	1, 4, 8
7601-54-9	Trisodium phosphate	✓	1, 2, 4
10101-89-0	Trisodium phosphate dodecahydrate	✓	1
77-86-1	Tromethamine	✓	3, 4
73049-73-7	Tryptone		8
1319-33-1	Ulexite		1, 2, 3, 8
1120-21-4	Undecane	✓	3, 8
57-13-6	Urea	✓	1, 2, 4, 8
1318-00-9	Vermiculite		2
24937-78-8	Vinyl acetate ethylene copolymer	✓	1, 4
25038-72-6	Vinylidene chloride/methylacrylate copolymer	✓	4
7732-18-5	Water	✓	2, 4, 8
8042-47-5	White mineral oil, petroleum		1, 2, 4
1330-20-7	Xylenes	✓	1, 2, 4
8013-01-2	Yeast extract		8
7440-66-6	Zinc	✓	2
3486-35-9	Zinc carbonate	✓	2
7646-85-7	Zinc chloride	✓	1, 2
1314-13-2	Zinc oxide	✓	1, 4
13746-89-9	Zirconium nitrate	✓	2, 6
62010-10-0	Zirconium oxide sulfate		1, 4

Table continued on next page

Table continued from previous page

CASRN	Chemical Name	IUPAC Name and Structure	Reference
7699-43-6	Zirconium oxychloride	✓	1, 2, 4
21959-01-3	Zirconium(IV) chloride tetrahydrofuran complex	✓	5
14644-61-2	Zirconium(IV) sulfate	✓	2, 6
197980-53-3	Zirconium, 1,1'-((2-((2-hydroxyethyl)(2-hydroxypropyl)amino)ethyl)imino)bis(2-propanol) complexes	✓	4
68909-34-2	Zirconium, acetate lactate oxo ammonium complexes		4, 8
174206-15-6	Zirconium, chloro hydroxy lactate oxo sodium complexes		4
113184-20-6	Zirconium, hydroxylactate sodium complexes		1, 4
101033-44-7	Zirconium,tetrakis[2-[bis(2-hydroxyethyl)amino-kN]ethanolato-kO]-	✓	1, 2, 4, 5

Table A-2 lists generic names of chemicals reported to be used in hydraulic fracturing fluids between 2005 and 2009. Generic chemical names provide limited information on the chemical, but are not specific enough to determine chemical structures. In some cases, the generic chemical name masks a specific chemical name and CASRN provided to the EPA and claimed as CBI by one or more of the nine hydraulic fracturing service companies.

Table A-2. List of generic names of chemicals reportedly used in hydraulic fracturing fluids. In some cases, the generic chemical name masks a specific chemical name and CASRN provided to the EPA and claimed as CBI by one or more of the nine hydraulic fracturing service companies.

Generic Chemical Name	Reference
2-Substituted aromatic amine salt	1, 4
Acetylenic alcohol	1
Acrylamide acrylate copolymer	4
Acrylamide copolymer	1, 4
Acrylamide modified polymer	4
Acrylamide-sodium acrylate copolymer	4
Acrylate copolymer	1
Acrylic copolymer	1
Acrylic polymer	1, 4
Acrylic resin	4
Acyclic hydrocarbon blend	1, 4
Acylbenzylpyridinium choride	8
Alcohol alkoxylate	1, 4
Alcohol and fatty acid blend	2
Alcohol ethoxylates	4
Alcohols	1, 4
Alcohols, C9-C22	1, 4
Aldehydes	1, 4, 5
Alfa-alumina	1, 4
Aliphatic acids	1, 2, 3, 4
Aliphatic alcohol	2
Aliphatic alcohol glycol ether	3, 4
Aliphatic alcohols, ethoxylated	2
Aliphatic amine derivative	1
Aliphatic carboxylic acid	4
Alkaline bromide salts	1, 4
Alkaline metal oxide	4
Alkanes/alkenes	4
Alkanolamine derivative	2
Alkanolamine/aldehyde condensate	1, 2, 4

Table continued on next page

Table continued from previous page

Generic Chemical Name	Reference
Alkenes	1, 4
Alklaryl sulfonic acid	1, 4
Alkoxylated alcohols	1
Alkoxylated amines	1, 4
Alkyaryl sulfonate	1, 2, 3, 4
Alkyl alkoxylate	1, 4
Alkyl amide	4
Alkyl amine	1, 4
Alkyl amine blend in a metal salt solution	1, 4
Alkyl aryl amine sulfonate	4
Alkyl aryl polyethoxy ethanol	3, 4
Alkyl dimethyl benzyl ammonium chloride	4
Alkyl esters	1, 4
Alkyl ether phosphate	4
Alkyl hexanol	1, 4
Alkyl ortho phosphate ester	1, 4
Alkyl phosphate ester	1, 4
Alkyl phosphonate	4
Alkyl pyridines	2
Alkyl quaternary ammonium chlorides	1, 4
Alkyl quaternary ammonium salt	4
Alkylamine alkylaryl sulfonate	4
Alkylamine salts	2
Alkylaryl sulfonate	1, 4
Alkylated quaternary chloride	1, 2, 4
Alkylated sodium naphthalenesulphonate	2
Alkylbenzenesulfonate	2
Alkylbenzenesulfonic acid	1, 4, 5
Alkylethoammonium sulfates	1
Alkylphenol ethoxylates	1, 4
Alkylpyridinium quaternary	4
Alphatic alcohol polyglycol ether	2
Aluminum oxide	1, 4
Amide	4
Amidoamine	1, 4
Amine	1, 4

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Generic Chemical Name	Reference
Amine compound	4
Amine oxides	1, 4
Amine phosphonate	1, 4
Amine salt	1
Amino compounds	1, 4
Amino methylene phosphonic acid salt	1, 4
Ammonium alcohol ether sulfate	1, 4
Ammonium salt	1, 4
Ammonium salt of ethoxylated alcohol sulfate	1, 4
Amorphous silica	4
Amphoteric surfactant	2
Anionic acrylic polymer	2
Anionic copolymer	1, 4
Anionic polyacrylamide	1, 2, 4
Anionic polyacrylamide copolymer	1, 4, 6
Anionic polymer	1, 3, 4
Anionic surfactants	2, 4, 6
Antifoulant	1, 4
Antimonate salt	1, 4
Aqueous emulsion of diethylpolysiloxane	2
Aromatic alcohol glycol ether	1
Aromatic aldehyde	1, 4
Aromatic hydrocarbons	3, 4
Aromatic ketones	1, 2, 3, 4
Aromatic polyglycol ether	1
Arsenic compounds	4
Ashes, residues	4
Bentone clay	4
Biocide	4
Biocide component	1, 4
Bis-quaternary methacrylamide monomer	4
Blast furnace slag	4
Borate salts	1, 2, 4
Cadmium compounds	4
Carbohydrates	1, 2, 4
Carboxylmethyl hydroxypropyl guar	4

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Generic Chemical Name	Reference
Cationic polyacrylamide	4
Cationic polymer	2, 4
Cedar fiber, processed	2
Cellulase enzyme	1
Cellulose derivative	1, 2, 4
Cellulose ether	2
Cellulosic polymer	2
Ceramic	4
Chlorous ion solution	1
Chromates	1, 4
Chrome-free lignosulfonate compound	2
Citrus rutaceae extract	4
Common white	4
Complex alkylaryl polyo-ester	1
Complex aluminum salt	1, 4
Complex carbohydrate	2
Complex organometallic salt	1
Complex polyamine salt	7
Complex substituted keto-amine	1
Complex substituted keto-amine hydrochloride	1
Copper compounds	6
Coric oxide	4
Cotton dust (raw)	2
Cottonseed hulls	2
Cured acrylic resin	1, 4
Cured resin	1, 4, 5
Cured urethane resin	1, 4
Cyclic alkanes	1, 4
Defoamer	4
Dibasic ester	4
Dicarboxylic acid	1, 4
Diesel	1, 4, 6
Dimethyl silicone	1, 4
Dispersing agent	1
Emulsifier	4
Enzyme	4

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Generic Chemical Name	Reference
Epoxy	4
Epoxy resin	1, 4
Essential oils	1, 4
Ester Salt	2, 4
Esters	2, 4
Ether compound	4
Ether salt	4
Ethoxylated alcohol blend	4
Ethoxylated alcohol/ester mixture	4
Ethoxylated alcohols	1, 2, 4, 5, 7
Ethoxylated alkyl amines	1, 4
Ethoxylated amine blend	4
Ethoxylated amines	1, 4
Ethoxylated fatty acid	4
Ethoxylated fatty acid ester	1, 4
Ethoxylated nonionic surfactant	1, 4
Ethoxylated nonylphenol	1, 2, 4
Ethoxylated sorbitol esters	1, 4
Ethylene oxide-nonylphenol polymer	4
Fatty acid amine salt mixture	4
Fatty acid ester	1, 2, 4
Fatty acid tall oil	1, 4
Fatty acids	1
Fatty acid, ethoxylate	4
Fatty alcohol alkoxylate	1, 4
Fatty alkyl amine salt	1, 4
Fatty amine carboxylates	1, 4
Fatty imidazoline	4
Fluoroaliphatic polymeric esters	1, 4
Formaldehyde polymer	1
Glass fiber	1, 4
Glyceride esters	2
Glycol	4
Glycol blend	2
Glycol ethers	1, 4, 7
Ground cedar	2

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Generic Chemical Name	Reference
Ground paper	2
Guar derivative	1, 4
Guar gum	4
Haloalkyl heteropolycycle salt	1, 4
Hexanes	1
High molecular weight polymer	2
High pH conventional enzymes	2
Hydrocarbons	1
Hydrogen solvent	4
Hydrotreated and hydrocracked base oil	1, 4
Hydrotreated distillate, light C9-16	4
Hydrotreated heavy naphthalene	5
Hydrotreated light distillate	2, 4
Hydrotreated light petroleum distillate	4
Hydroxyalkyl imino carboxylic sodium salt	2
Hydroxycellulose	6
Hydroxyethyl cellulose	1, 2, 4
Imidazolium compound	4
Inner salt of alkyl amines	1, 4
Inorganic borate	1, 4
Inorganic chemical	4
Inorganic particulate	1, 4
Inorganic salt	2, 4
Iso-alkanes/n-alkanes	1, 4
Isomeric aromatic ammonium salt	1, 4
Latex	2, 4
Lead compounds	4
Low toxicity base oils	1, 4
Lubra-Beads course	4
Maghemite	1, 4
Magnetite	1, 4
Metal salt	1
Metal salt solution	1
Mineral	1, 4
Mineral fiber	2
Mineral filler	1

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Generic Chemical Name	Reference
Mineral oil	4
Mixed titanium ortho ester complexes	1, 4
Modified acrylamide copolymer	2, 4
Modified acrylate polymer	4
Modified alkane	1, 4
Modified bentonite	4
Modified cycloaliphatic amine adduct	1, 4
Modified lignosulfonate	2, 4
Naphthalene derivatives	1, 4
Neutralized alkylated napthalene sulfonate	4
Nickel chelate catalyst	4
Nonionic surfactant	1
N-tallowalkyltrimethylenediamines	4
Nuisance particulates	1, 2, 4
Nylon	4
Olefinic sulfonate	1, 4
Olefins	1, 4
Organic acid salt	1, 4
Organic acids	1, 4
Organic alkyl amines	4
Organic chloride	4
Organic modified bentonite clay	4
Organic phosphonate	1, 4
Organic phosphonate salts	1, 4
Organic phosphonic acid salts	1, 4
Organic polymer	4
Organic polyol	4
Organic salt	1, 4
Organic sulfur compound	1, 4
Organic surfactants	1
Organic titanate	1, 4
Organo amino silane	4
Organo phosphonic acid	4
Organo phosphonic acid salt	4
Organometallic ammonium complex	1
Organophilic clay	4

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Generic Chemical Name	Reference
Oxidized tall oil	2
Oxoaliphatic acid	2
Oxyalkylated alcohol	1, 4
Oxyalkylated alkyl alcohol	2, 4
Oxyalkylated alkylphenol	1, 2, 3, 4
Oxyalkylated fatty acid	1, 4
Oxyalkylated fatty alcohol salt	2
Oxyalkylated phenol	1, 4
Oxyalkylated phenolic resin	4
Oxyalkylated polyamine	1
Oxyalkylated tallow diamine	2
Oxyethylated alcohol	2
Oxylated alcohol	1, 4
P/F resin	4
Paraffinic naphthenic solvent	1
Paraffinic solvent	1, 4
Paraffin inhibitor	4
Paraffins	1
Pecan shell	2
Petroleum distallate blend	2, 3, 4
Petroleum gas oils	1
Petroleum hydrocarbons	4
Petroleum solvent	2
Phosphate ester	1, 4
Phosphonate	2
Phosphonic acid	1, 4
Phosphoric acid, mixed polyoxyalkylene aryl and alkyl esters	4
Plasticizer	1, 2
Polyacrylamide copolymer	4
Polyacrylamides	1
Polyacrylate	1, 4
Polyactide resin	4
Polyalkylene esters	4
Polyaminated fatty acid	2
Polyaminated fatty acid surfactants	2
Polyamine	1, 4

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Generic Chemical Name	Reference
Polyamine polymer	4
Polyanionic cellulose	1
Polyaromatic hydrocarbons	6
Polycyclic organic matter	6
Polyelectrolyte	4
Polyether polyol	2
Polyethoxylated alkanol	2, 3, 4
Polyethylene copolymer	4
Polyethylene glycols	4
Polyethylene wax	4
Polyglycerols	2
Polyglycol	2
Polyglycol ether	6
Polylactide resin	4
Polymer	2, 4
Polymeric hydrocarbons	3, 4
Polymerized alcohol	4
Polymethacrylate polymer	4
Polyol phosphate ester	2
Polyoxyalkylene phosphate	2
Polyoxyalkylene sulfate	2
Polyoxyalkylenes	1, 4, 7
Polyphenylene ether	4
Polyphosphate	4
Polypropylene glycols	2
Polyquaternary amine	4
Polysaccaride polymers in suspension	2
Polysaccharide	4
Polysaccharide blend	4
Polyvinylalcohol/polyvinylactetate copolymer	4
Potassium chloride substitute	4
Quarternized heterocyclic amines	4
Quaternary amine	2, 4
Quaternary amine salt	4
Quaternary ammonium chloride	4
Quaternary ammonium compound	1, 2, 4

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Generic Chemical Name	Reference
Quaternary ammonium salts	1, 2, 4
Quaternary compound	1, 4
Quaternary salt	1, 4
Quaternized alkyl nitrogenated compd	4
Red dye	4
Refined mineral oil	2
Resin	4
Salt of amine-carbonyl condensate	3, 4
Salt of fatty acid/polyamine reaction product	3, 4
Salt of phosphate ester	1
Salt of phosphono-methylated diamine	1, 4
Salts	4
Salts of oxyalkylated fatty amines	4
Sand	4
Sand, AZ silica	4
Sand, brown	4
Sand, sacked	4
Sand, white	4
Secondary alcohol	1, 4
Silica sand, 100 mesh, sacked	4
Silicone emulsion	1
Silicone ester	4
Sodium acid pyrophosphate	4
Sodium calcium magnesium polyphosphate	4
Sodium phosphate	4
Sodium salt of aliphatic amine acid	2
Sodium xylene sulfonate	4
Softwood dust	2
Starch blends	6
Substituted alcohol	1, 2, 4
Substituted alkene	1
Substituted alklyamine	1, 4
Substituted alkyne	4
Sulfate	4
Sulfomethylated tannin	2, 5
Sulfonate	4

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Generic Chemical Name	Reference
Sulfonate acids	1
Sulfonate surfactants	1
Sulfonated asphalt	2
Sulfonic acid salts	1, 4
Sulfur compound	1, 4
Sulphonic amphoterics	4
Sulphonic amphoterics blend	4
Surfactant blend	3, 4
Surfactants	1, 2, 4
Synthetic copolymer	2
Synthetic polymer	4
Tallow soap	4
Telomer	4
Terpenes	1, 4
Titanium complex	4
Triethanolamine zirconium chelate	1 4
Triterpanes	4
Vanadium compounds	4
Wall material	1
Walnut hulls	1, 2, 4
Zirconium complex	2, 4
Zirconium salt	4

Table A-3 contains a list of chemicals with CASRNs that have been detected in flowback and produced water (collectively referred to as "hydraulic fracturing wastewater"). The table identifies chemicals that are also reported to be used in hydraulic fracturing fluids (Table A-1).

Table A-3. List of CASRNs and names of chemicals detected in hydraulic fracturing wastewater. Chemicals also reportedly used in hydraulic fracturing fluids are marked with an "✓."

CASRN	Chemical Name	Also Listed in Table A 1	Reference
87-61-6	1,2,3-Trichlorobenzene		3, 9
120-82-1	1,2,4-Trichlorobenzene		9
95-63-6	1,2,4-Trimethylbenzene	✓	3, 9, 10
57-55-6	1,2-Propanediol	✓	3, 9
108-67-8	1,3,5-Trimethylbenzene	✓	3, 9, 10
123-91-1	1,4-Dioxane	✓	9, 10
105-67-9	2,4-Dimethylphenol		3, 9, 10
87-65-0	2,6-Dichlorophenol		3, 9
91-57-6	2-Methylnaphthalene		3, 9, 10
95-48-7	2-Methylphenol		3, 9, 10
79-31-2	2-Methylpropanoic acid		10
109-06-8	2-Methylpyridine		3, 9
503-74-2	3-Methylbutanoic acid		10
108-39-4	3-Methylphenol		3, 9, 10
106-44-5	4-Methylphenol		3, 9, 10
57-97-6	7,12-Dimethylbenz(a)anthracene		3, 9
64-19-7	Acetic acid	✓	3, 9, 10
67-64-1	Acetone	✓	3, 9, 10
98-86-2	Acetophenone	✓	3, 9
107-02-8	Acrolein	✓	9
107-13-1	Acrylonitrile		3, 9
309-00-2	Aldrin		3, 9
7429-90-5	Aluminum	✓	3, 9, 10
7664-41-7	Ammonia	✓	3, 9, 10
7440-36-0	Antimony		3, 9, 10
12672-29-6	Aroclor 1248		3, 9
7440-38-2	Arsenic	✓	3, 9, 10
7440-39-3	Barium		3, 9, 10
71-43-2	Benzene	✓	3, 9, 10
50-32-8	Benzo(a)pyrene		3, 9
205-99-2	Benzo(b)fluoranthene		3, 9
191-24-2	Benzo(g,h,i)perylene		3, 9, 10
207-08-9	Benzo(k)fluoranthene		3, 9
100-51-6	Benzyl alcohol		3, 9, 10

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CASRN	Chemical Name	Also Listed in Table A 1	Reference
7440-41-7	Beryllium		3, 9, 10
319-85-7	beta-1,2,3,4,5,6-Hexachlorocyclohexane		3, 9
111-44-4	Bis(2-chloroethyl) ether	✓	3, 9
7440-42-8	Boron		3, 9, 10
24959-67-9	Bromide (-1)		3, 9, 10
75-27-4	Bromodichloromethane		3
75-25-2	Bromoform		3, 9, 10
107-92-6	Butanoic acid		9, 10
104-51-8	Butylbenzene		9, 10
7440-43-9	Cadmium		3, 9, 10
10045-97-3	Caesium 137		3
7440-70-2	Calcium		3, 9, 10
124-38-9	Carbon dioxide	✓	3, 9, 10
75-15-0	Carbon disulfide		3, 9
16887-00-6	Chloride	✓	3, 9, 10
7782-50-5	Chlorine	✓	3, 10
124-48-1	Chlorodibromomethane		3
67-66-3	Chloroform		3, 9, 10
74-87-3	Chloromethane		3, 10
7440-47-3	Chromium		3, 9, 10
16065-83-1	Chromium (III), insoluble salts	✓	3
18540-29-9	Chromium (VI)	✓	3, 10
7440-48-4	Cobalt		3, 9, 10
7440-50-8	Copper	✓	3, 9, 10
98-82-8	Cumene	✓	3, 9
57-12-5	Cyanide, free		3, 9, 10
319-86-8	delta-Hexachlorocyclohexane		9
117-81-7	Di(2-ethylhexyl) phthalate	✓	3, 9, 10
53-70-3	Dibenz(a,h)anthracene		3, 9
84-74-2	Dibutyl phthalate		3, 9, 10
75-09-2	Dichloromethane		9, 10
60-57-1	Dieldrin		9
84-66-2	Diethyl phthalate		9
117-84-0	Dioctyl phthalate		9, 10
122-39-4	Diphenylamine		3, 9
959-98-8	Endosulfan I		3, 9
33213-65-9	Endosulfan II		3, 9
7421-93-4	Endrin aldehyde		3, 9

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CASRN	Chemical Name	Also Listed in Table A 1	Reference
100-41-4	Ethylbenzene	✓	3, 9, 10
107-21-1	Ethylene glycol	✓	3, 9
206-44-0	Fluoranthene		3, 9
86-73-7	Fluorene		3, 9, 10
16984-48-8	Fluoride		3, 9, 10
64-18-6	Formic acid	✓	10
76-44-8	Heptachlor		3, 9
1024-57-3	Heptachlor epoxide		3, 9
111-14-8	Heptanoic acid		10
142-62-1	Hexanoic acid		10
193-39-5	Indeno(1,2,3-cd)pyrene		3, 9
7439-89-6	Iron	✓	3, 9, 10
67-63-0	Isopropanol	✓	3, 9
7439-92-1	Lead	✓	3, 9, 10
58-89-9	Lindane		3, 9
7439-93-2	Lithium		3, 9, 10
7439-95-4	Magnesium		3, 9, 10
7439-96-5	Manganese		3, 9, 10
7439-97-6	Mercury		3, 9, 10
67-56-1	Methanol	✓	3, 9
74-83-9	Methyl bromide		3, 9
78-93-3	Methyl ethyl ketone		3, 9, 10
7439-98-7	Molybdenum		3, 9, 10
91-20-3	Naphthalene	✓	3, 9, 10
7440-02-0	Nickel		3, 9, 10
86-30-6	N-Nitrosodiphenylamine		3, 9
72-55-9	p,p'-DDE		3, 9
99-87-6	p-Cymene		9, 10
109-52-4	Pentanoic acid		10
85-01-8	Phenanthrene	✓	3, 9, 10
108-95-2	Phenol	✓	3, 9, 10
298-02-2	Phorate		9
7723-14-0	Phosphorus		3, 9
7440-09-7	Potassium		3, 9, 10
79-09-4	Propionic acid		10
103-65-1	Propylbenzene		9
129-00-0	Pyrene		9, 10
110-86-1	Pyridine		3, 9, 10

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CASRN	**Chemical Name**	**Also Listed in Table A 1**	**Reference**
13982-63-3	Radium 226		3, 10
7440-14-4	Radium 226,228		3
15262-20-1	Radium 228		3, 10
94-59-7	Safrole		3, 9
135-98-8	sec-Butylbenzene		9
7782-49-2	Selenium		3, 9, 10
7631-86-9	Silica	✓	10
7440-21-3	Silicon (elemental)		10
7440-22-4	Silver		3, 9, 10
7440-23-5	Sodium		3, 9, 10
7440-24-6	Strontium		3, 9, 10
14808-79-8	Sulfate	✓	3, 9, 10
14265-45-3	Sulfite		3
127-18-4	Tetrachloroethylene		3, 9
7440-28-0	Thallium and Compounds		3, 9, 10
7440-31-5	Tin		9, 10
7440-32-6	Titanium		3, 9, 10
108-88-3	Toluene	✓	3, 9, 10
7440-62-2	Vanadium		3, 10
1330-20-7	Xylenes	✓	3, 9, 10
7440-66-6	Zinc	✓	3, 9, 10
7440-67-7	Zirconium		3

Table A-4 contains a list of chemicals and properties that are detected in flowback and produced water (collectively referred to as "hydraulic fracturing wastewater").

Table A-4. List of chemicals and properties detected in hydraulic fracturing wastewater.

Chemical Name / Property	Reference
Alkalinity	3, 9, 10
Alkalinity, carbonate (as $CaCO_3$)	3, 9, 10
Alpha radiation	3
Aluminum, dissolved	3, 9
Barium strontium P.S.	3
Barium, dissolved	3, 9
Beta radiation	3
Bicarbonates (HCO_3)	3, 10
Biochemical oxygen demand	3, 9, 10
Cadmium, dissolved	3, 9
Calcium, dissolved	3, 9
Chemical oxygen demand	3, 9, 10
Chromium (VI), dissolved	3
Chromium, dissolved	3, 9
Cobalt, dissolved	3, 9
Coliform	3
Color	3
Conductivity	3, 9, 10
Hardness as $CaCO_3$	3, 9, 10
Heterotrophic plate count	3
Hexanoic acid	10
Iron, dissolved	3, 9
Lithium, dissolved	3, 9
Magnesium, dissolved	3, 9
Manganese, dissolved	3, 9
Nickel, dissolved	3, 9
Nitrate, as N	3, 9, 10
Nitrogen, total as N	3
Oil and grease	3, 9, 10
Petroleum hydrocarbons	3
pH	3, 9, 10
Phenols	3
Potassium, dissolved	3, 9
Salt	3
Scale inhibitor	3
Selenium, dissolved	3, 9
Silver, dissolved	3, 10
Sodium, dissolved	3, 10
Strontium, dissolved	3, 10
Surfactants	3
Total alkalinity	3, 9, 10
Total dissolved solids	3, 9, 10
Total Kjeldahl nitrogen	3, 9, 10
Total organic carbon	3, 9, 10
Total sulfide	9
Total suspended solids	3, 9, 10
Volatile acids	3, 9
Zinc, dissolved	3, 9

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Appendix B: Stakeholder Engagement[90]

B.1. Stakeholder Engagement Road Map for the EPA's Study on the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources

On March 18, 2010, at the request of the U.S. Congress, the EPA announced plans to develop a comprehensive research study on the potential impact of hydraulic fracturing on drinking water resources. The EPA believes a transparent, research-driven approach with significant stakeholder involvement can address questions about hydraulic fracturing and strengthen our clean energy future. The road map below outlines the EPA's plans to build upon its commitment to transparency and stakeholder engagement coordinated during the development of the Study Plan and will help inform the report of results.

Goals of Strengthened Stakeholder Engagement

- Increase technical engagement with the stakeholder community to ensure that the EPA has ongoing access to a broad range of expertise and data outside the agency.
- Improve public understanding of the goals and design of the study.
- Ensure that the EPA is current on changes in industry practices and technologies so the report of results reflects an up-to-date picture of hydraulic fracturing operations.
- Obtain timely and constructive feedback on projects undertaken as part of the study.

Increased Technical Engagement

In November 2012, the EPA held five roundtables focused on each stage of the water cycle:

- *Water acquisition.* This study takes steps to examine potential changes in the quantity of water available for drinking and potential changes in drinking water quality that result from acquisition for hydraulic fracturing. The EPA is aware that the use of recycling is rapidly growing and that this may affect the need to acquire water for hydraulic fracturing.
- *Chemical mixing.* The study examines the potential release of chemicals used in hydraulic fracturing to surface and ground water through onsite spills and/or leaks and compiles information on hydraulic fracturing fluids and chemicals from publicly available data, data provided by nine hydraulic fracturing service companies and other sources.
- *Flowback.* The study examines available data regarding release to surface or ground water through spills or leakage from onsite storage.
- *Water treatment and disposal.* The study examines the potential for contaminants to reach drinking water due to surface water discharge, the effectiveness of current wastewater treatment, and the potential formation of disinfection byproducts in drinking water treatment facilities.

[90] The text and figure included in this appendix were taken from http://www.epa.gov/hfstudy/stakeholder-roadmap.html. Please see this website for updated information as it becomes available.

- *Well injection.* The study takes steps to examine the potential for release of hydraulic fracturing fluids to ground water due to inadequate well construction or operation, movement of hydraulic fracturing fluids from the target formation to drinking water aquifers through local man-made or natural features (e.g., other production or abandoned wells and existing faults or fractures).

Based on feedback from these roundtables, the EPA will host in-depth technical workshops to address specific issues in greater detail. These technical workshops will begin in February 2013 and continue as needed. Upon completion of the last technical workshop, the EPA will reconvene the original roundtables to review the work addressed in the technical workshop series.

Improve Public Understanding

To improve public understanding of the study, the EPA staff will increase the frequency of webinars. For instance, after the initial set of roundtables and each technical workshop, the EPA will host a webinar to report out to the public on these. The EPA will continue to provide regular electronic updates to its list of stakeholders.

In addition to the webinars, the EPA staff will regularly update its hydraulic fracturing study website with up-to-date materials and identify opportunities for briefings and updates on the study to stakeholders (e.g., annual or regional meetings of industry trade associations, annual meetings of environmental/public health groups, academic conferences, annual or regional meetings of water utilities, and tribal meetings).

The EPA has previously committed to the release in December 2012 of a progress report on the study. While the progress report will not make any final findings or conclusions, it will provide the public with an update on study activities and future work.

Ensure the EPA is Current on Industry Practices

To ensure that the EPA is up-to-date on evolving industry practices and technologies, the EPA will publish a *Federal Register* notice in late 2012 to create a docket where stakeholders can submit peer-reviewed data from ongoing or completed studies. This initial request will be followed up with requests in 2013 and 2014.

Obtain Timely Feedback

The EPA intends to receive timely feedback on the projects conducted as part of the study through the roundtables and technical workshops described above. In addition, the EPA's Science Advisory Board is forming a panel of independent experts who will provide advice and review under the auspices of the Science Advisory Board on the EPA's hydraulic fracturing research described in its 2012 Progress Report. The EPA plans to use such advice for the development of a report of results, estimated to be released in late 2014, which will also be reviewed by the Science Advisory Board. In addition, this panel may also provide advice on other technical documents and issues related to hydraulic fracturing upon further request by the EPA. The panel will provide opportunities for public comment in connection with these activities.

B.2 Stakeholder Road Map and Timeline

Increase technical engagement with the stakeholder community to ensure that the EPA has ongoing access to a broad range of expertise and data outside the agency.

Plan: The week of November 12, 2012, EPA held five roundtables focused on each stage of the water cycle, to be followed in Spring 2013 by a series of technical workshops on topics identified during the roundtables.

Implementation:

- Identify participants for meetings (September 2012):
  - The EPA consulted with industry, non-governmental organizations, states, and tribes through a series of one-on-one meetings in September to present the plan for the roundtables and ask for potential invitees with technical expertise. The EPA then selected invitees with appropriate technical backgrounds.
  - Roundtable participants numbered 15-20 in addition to the EPA staff.
- Kick-off (October 2012)
  - The EPA hosted a kick-off (virtual) meeting with technical representatives representing a broad range of stakeholders to lay out the context, goals, and logistics for the roundtables.
- Roundtables (November 14–16, 2012)
  - Each meeting was professionally facilitated.
  - All roundtables occurred in DC. These were half-day meetings.
- Workshops (February 2013 through April 2013)
- Second round of roundtables (Summer/Fall 2013)

Obtain timely and constructive feedback on projects undertaken as part of the study and ensure that the EPA is current on changes in industry practices and technologies so the report of results reflects an up-to-date picture of hydraulic fracturing operations.

Plan: Issue *Federal Register* notices in 2012, 2013, and 2014 requesting additional data and information to inform the study.[91] The notices will request peer-reviewed data and reports that can help answer the research questions, for example, the content of hydraulic fracturing flowback and produced water; the location of prior wastewater treatment pits, ponds, lagoons, and tanks; specific sources of water used for hydraulic fracturing; specific water quality requirements for use of water or reuse of waste water in hydraulic fracturing; partitioning of constituents into gas solid and liquid components (particularly the fate of metals, organics, and radionuclides).

[91] The first *Federal Register* notice was published in November 2012 and is available at http://www.gpo.gov/fdsys/pkg/FR-2012-11-09/pdf/2012-27452.pdf.

Implementation:

- Technical workshops on specific technical topics suggested by roundtable participants (begin February 2013)
- These sessions will flow from roundtable discussions. The EPA will convene experts to address specific issues of data collection, method or data interpretation (i.e., how to find more comprehensive/reliable spill data; how to get good data for the environmental justice analysis, etc.). The EPA will issue the first *Federal Register* notice in late 2012 to request peer-reviewed data and studies that can help answer the research questions. Additional *Federal Register* notices will request peer-reviewed information and will be published annually in 2013 and 2014.

Improve public understanding of the goals and design of the study.

Plan: In addition to the organized technical meetings, the EPA will seek opportunities (such as association or state organization meetings) to provide informal briefings and updates on the study to a diverse range of stakeholders, including states, non-governmental organizations, academia, and industry. The EPA will also increase the frequency of webinars, hosting them after each technical meeting to report out to the public on the discussion.

Implementation: The EPA will host monthly webinars following the initial set of roundtables and each technical workshop to inform the public of topics discussed. The EPA will develop and publish a calendar of events where presentations on the study will be made.

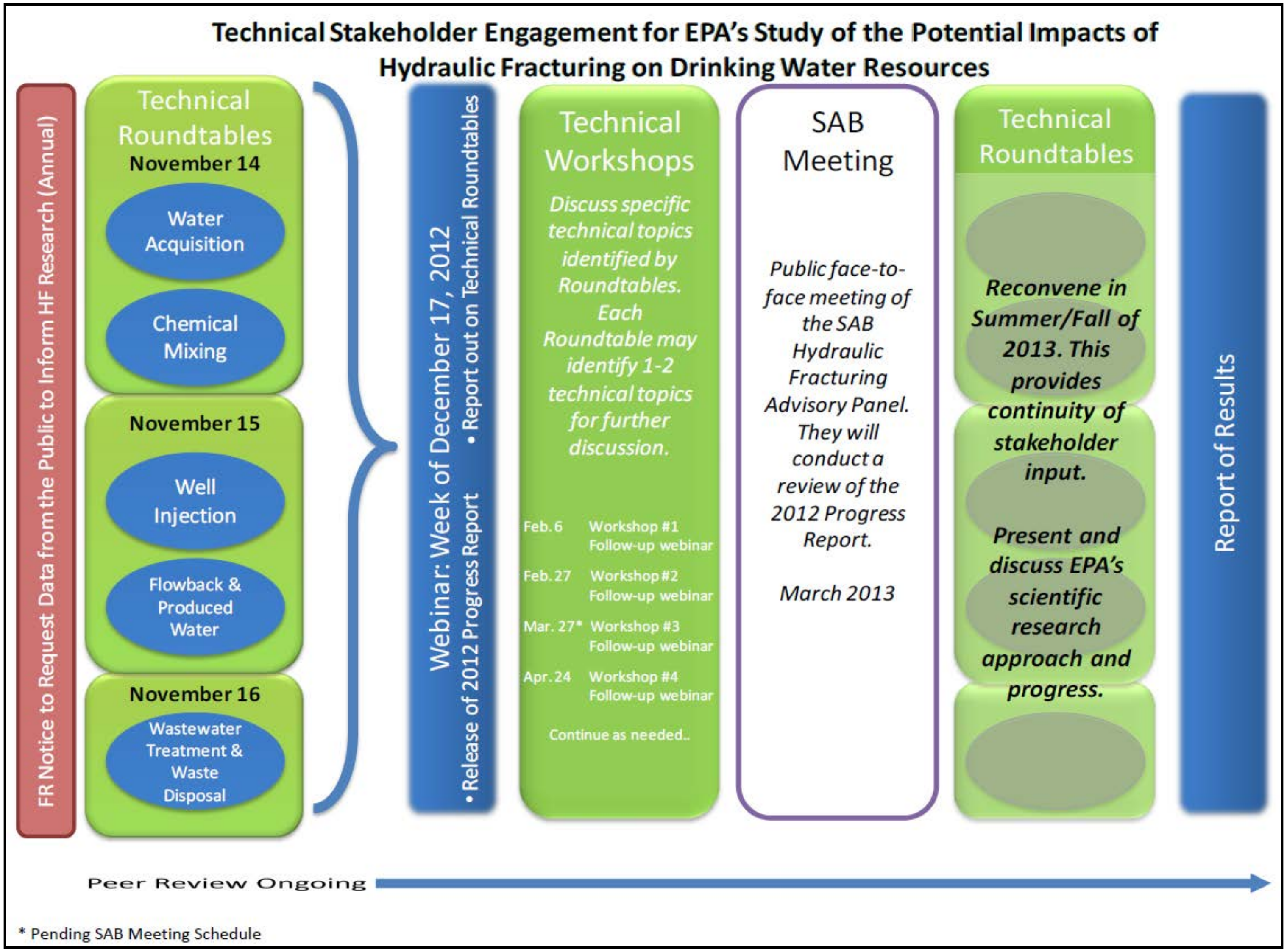

Figure B-1. Timeline for technical roundtables and workshops. The goals of this enhanced engagement process are to improve public understanding of the study, ensure that the EPA is current on changes in industry practices and technologies so that the report of results reflects an up-to-date picture of hydraulic fracturing operations, and obtain timely and constructive feedback on ongoing research projects.

Appendix C: Summary of QAPPs

This appendix provides a quick reference table for QAPPs associated with the research projects that comprise the EPA's *Study of the Potential Impacts of Drinking Water Resources.* Current versions of the QAPPs are available at http://www.epa.gov/hfstudy/qapps.html.

Table C-1. QAPPs associated with the research projects discussed in this progress report.

Research Project	QAPP Title
Literature Review	QAPP for Hydraulic Fracturing Data and Literature Evaluation for the EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*
Spills Database Analysis	QAPP for Hydraulic Fracturing Surface Spills Data Analysis
Service Company Analysis	Final QAPP for the Evaluation of Information on Hydraulic Fracturing
	QAPP for Analysis of Data Received from Nine Hydraulic Fracturing Service Companies
Well File Review	QAPP for Hydraulic Fracturing
	National Hydraulic Fracturing Study Evaluation of Existing Production Well File Contents: QAPP
	Supplemental Programmatic QAPP for Work Assignment 4-58: National Hydraulic Fracturing Study Evaluation of Existing Production Well File Contents
FracFocus Analysis	Supplemental Programmatic QAPP for Work Assignment 4-58: National Hydraulic Fracturing Study Evaluation of Existing Production Well File Contents
	QAPP for Analysis of Data Extracted from FracFocus
Subsurface Migration Modeling	Analysis of Environmental Hazards Related to Hydrofracturing
Surface Water Modeling	QAPP for Surface Water Transport of Hydraulic Fracturing-Derived Waste Water
Water Availability Modeling	Data Collection/Mining for Hydraulic Fracturing Case Studies
	Modeling the Impact of Hydraulic Fracturing on Water Resources Based on Water Acquisition Scenarios
Source Apportionment Studies	QAPP for Hydraulic Fracturing Waste Water Source Apportionment Study
Wastewater Treatability Studies	Fate, Transport, and Characterization of Contaminants in Hydraulic Fracturing Water in Wastewater Treatment Processes
Br-DBP Precursor Studies	Formation of Disinfection By-Products from Hydraulic Fracturing Fluid Constituents: QAPP
Analytical Method Development	QAPP for the Chemical Characterization of Select Constituents Relevant to Hydraulic Fracturing
	QAPP for the Interlaboratory Verification and Validation of Diethylene Glycol, Triethylene Glycol, Tetraethylene Glycol, 2-Butoxyethanol and 2-Methoxyethanol in Ground and Surface Waters by Liquid Chromatography/Tandem Mass Spectrometry

Table continued on next page

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Research Project	QAPP Title
Toxicity Assessment	QAPP: Health and Toxicity Theme, Hydraulic Fracturing Study
	QAPP for Chemical Information Quality Review and Physicochemical Property Calculations for Hydraulic Fracturing Chemical Lists
Las Animas and Huerfano Counties, Colorado	Hydraulic Fracturing Retrospective Case Study, Raton Basin, CO
Dunn County, North Dakota	Hydraulic Fracturing Retrospective Case Study, Bakken Shale, Killdeer and Dunn County, ND
Bradford County, Pennsylvania	Hydraulic Fracturing Retrospective Case Study, Bradford-Susquehanna Counties, PA
Washington County, Pennsylvania	Hydraulic Fracturing Retrospective Case Study, Marcellus Shale, Washington County, PA
Wise County, Texas	Hydraulic Fracturing Retrospective Case Study, Wise and Denton Cos., TX

Appendix D: Divisions of Geologic Time

Figure E-1 is reproduced from a USGS fact sheet, “Divisions of Geologic Time: Major Chronostratigraphic and Geochronological Units.” A geologic timescale relates rock layers to time.

Chronstratigraphic units refer to specific rock layers while geochronological units refer to specific time periods.

Reference

US Geological Survey. 2010. Divisions of Geologic Time: Major Chronostratigraphic and Geochronological Units. Fact Sheet 2010-3059. US Geological Survey. Available at http://pubs.usgs.gov/fs/2010/3059/pdf/FS10-3059.pdf. Accessed November 30, 2012.

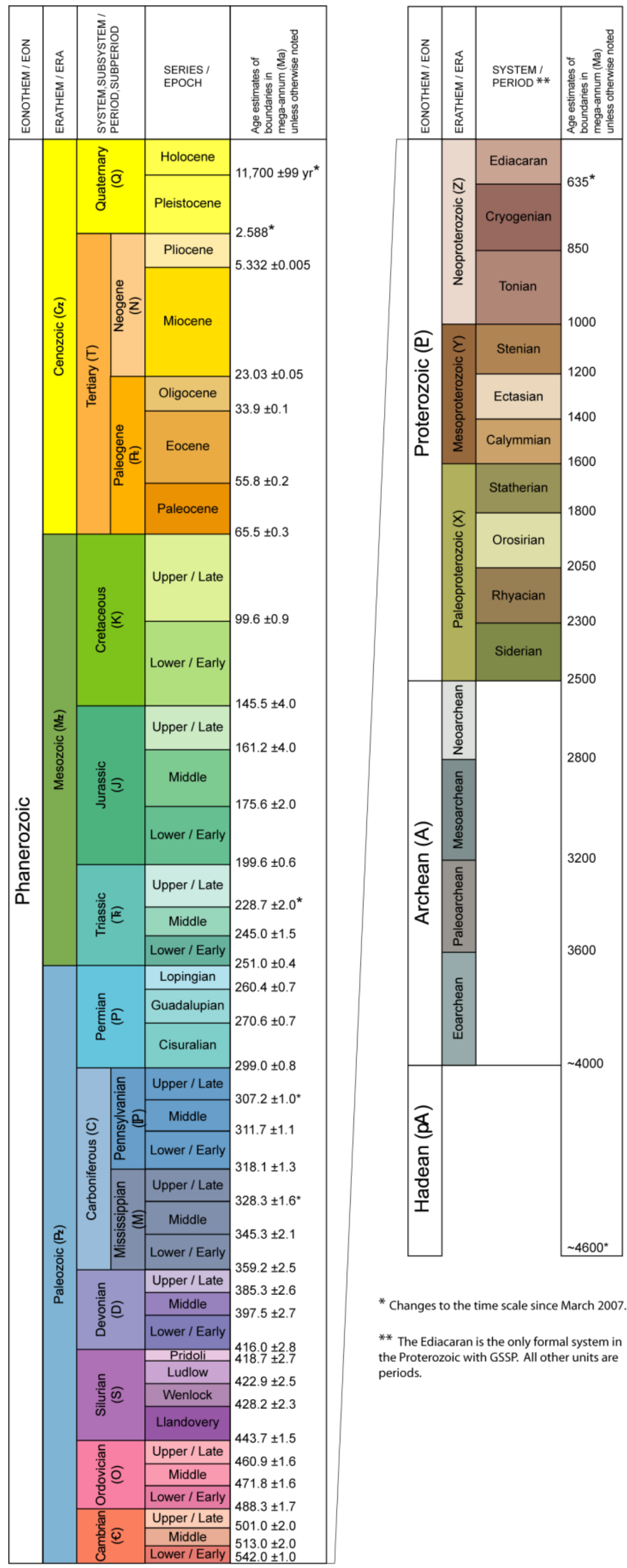

Figure D-1. Divisions of geologic time approved by the USGS Geologic Names Committee (2010).The chart shows major chronostratigraphic and geochronologic units.

Glossary

Acid mine drainage: Drainage of water from areas that have been mined for coal of other mineral ores. The water has a low pH because of its contact with sulfur-bearing material and is harmful to aquatic organisms. (2)

Adsorption: Adhesion of molecules of gas, liquid, or dissolved solids to a surface. (2)

Aeration: A process that promotes biological degradation of organic matter in water. The process may be passive (as when waste is exposed to air) or active (as when a mixing or bubbling device introduces the air). (2)

Ambient water quality: Natural concentration of water quality constituents prior to mixing of either point or nonpoint source load of contaminants. Reference ambient concentration is used to indicate the concentration of a chemical that will not cause adverse impact to human health. (2)

Analysis of existing data: The process of gathering and summarizing existing data from various sources to provide current information on hydraulic fracturing activities.

Analyte: The element, ion, or compound that an analysis seeks to identify; the compound of interest. (2)

Annulus: Either the space between the casing of a well and the wellbore or the space between the tubing and casing of a well. (2)

API number: A unique identifying number for all oil and gas wells drilled in the United States. The system was developed by the American Petroleum Institute. (1)

Aquifer: An underground geological formation, or group of formations, containing water. A source of ground water for wells and springs. (2)

Baseline data: Initial information on a program or program components collected prior to receipt of services or participation activities. Often gathered through intake interviews and observations and used later for comparing measures that determine changes in a program. (2)

Case study: An approach often used in research to better understand real-world situations or events using a systematic process for the collection and analysis of data.

> **Prospective case study:** A study of sites where hydraulic fracturing will occur after the research is initiated. These case studies allow sampling and characterization of the site prior to, and after, water extraction, drilling, hydraulic fracturing fluid injection, flowback, and gas production. The data collected during prospective case studies will allow the EPA to evaluate any changes in water quality over time.
>
> **Retrospective case study:** A study of sites where hydraulic fracturing has occurred nearby, with a focus on sites with reported instances of drinking water resource contamination.

These studies will use existing data, sampling, and possibly modeling to determine whether reported impacts are due to hydraulic fracturing activities or other sources.

Casing: Pipe cemented in the well to seal off formation fluids and to keep the hole from caving in. (1)

Chemical Abstracts Service: Provides information on chemical properties and interactions. Every year, the Chemical Abstracts Service updates and writes new chemical abstracts on well over a million different chemicals, including each chemical's composition, structure, characteristics, and different names. Each abstract is accompanied by a registration number, or CASRN. (2)

Coalbed methane: Methane contained in coal seams. A coal seam is a layer or stratum of coal parallel to the rock stratification.

Confidential business information (CBI): Information that contains trade secrets, commercial or financial information, or other information that has been claimed as confidential by the submitter. The EPA has special procedures for handling such information. (2)

Contaminant: A substance that is either present in an environment where it does not belong or is present at levels that might cause harmful (adverse) health effects. (2)

Conventional reservoir: A reservoir in which buoyant forces keep hydrocarbons in place below a sealing caprock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellbores. The term is used to make a distinction from shale and other unconventional reservoirs, in which gas might be distributed throughout the reservoir at the basin scale, and in which buoyant forces or the influence of a water column on the location of hydrocarbons within the reservoir are not significant. (5)

Discharge: Any emission (other than natural seepage), intentional or unintentional. Includes, but is not limited to, spilling, leaking, pumping, pouring, emitting, emptying or dumping. (2)

Disinfection byproduct (DBP): A compound formed by the reaction of a disinfectant such as chlorine with organic material in the water supply. (2)

Drinking water resource: Any body of water, ground or surface, that could currently, or in the future, serve as a source of drinking water for public or private water supplies.

DSSTox: The Distributed Structure-Searchable Toxicity Database Network, a project of the EPA's National Center for Computational Toxicology. The DSSTox website provides a public forum for publishing downloadable, structure-searchable, standardized chemical structure files associated with chemical inventories or toxicity datasets of environmental relevance. (2)

Effluent: Waste material being discharged into the environment, either treated or untreated. (2)

Environmental justice: The fair treatment of people of all races, cultures, incomes, and educational levels with respect to the development and enforcement of environmental laws, regulations, and policies. The fair distribution of environmental risks across socioeconomic and racial groups. (2)

Flowback: After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses, and water and excess proppant flow up through the wellbore to the surface. The water that returns to the surface is commonly referred to as “flowback.” (3)

Fluid formulation: The entire suite of products and carrier fluid injected into a well during hydraulic fracturing.

Formation: A geological formation is a body of earth material with distinctive and characteristic properties and a degree of homogeneity in its physical properties. (2)

Formation water: Water that occurs naturally within the pores of rock. (5)

FracFocus: National registry for chemicals used in hydraulic fracturing, jointly developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. Serves as an online repository where oil and gas well operators can upload information regarding the chemical compositions of hydraulic fracturing fluids used in specific oil and gas production wells. Also contains spatial information for well locations and information on well depth and water use.

Geographic information system (GIS): A computer system designed for storing, manipulating, analyzing, and displaying data in a geographic context, usually as maps. (2)

Gross α: The total radioactivity due to alpha particle emission as inferred from measurements on a dry sample. (2)

Gross β: The total radioactivity due to beta particle emission as inferred from measurements on a dry sample. (2)

Ground water: The supply of fresh water found beneath the Earth’s surface, usually in aquifers, which supply wells and springs. It provides a major source of drinking water. (2)

Halite: A soft, soluble evaporate mineral commonly known as salt or rock salt. Can be critical in forming hydrocarbon traps and seals because it tends to flow rather than fracture during deformation, thus preventing hydrocarbons from leaking out of a trap even during and after some types of deformation. (5)

Hazardous air pollutants: Air pollutants that are not covered by ambient air quality standards but which, as defined in the Clean Air Act, may present a threat of adverse human health effects or adverse environmental effects. Although classified as air pollutants, they may also impact drinking water. (2)

Horizontal drilling: Drilling a portion of a well horizontally to expose more of the formation surface area to the wellbore. (1)

Hydraulic fracturing: The process of using high pressure to pump sand along with water and other fluids into subsurface rock formations in order to improve flow of oil and gas into a wellbore. (1)

> **Fluid:** Specially engineered fluids containing chemical additives and proppant that are pumped under high pressure into the well to create and hold open fractures in the formation.
>
> **Wastewater:** Flowback and produced water, where flowback is the fluid returned to the surface after hydraulic fracturing has occurred but before the well is placed into production, and produced water is the fluid returned to the surface after the well has been placed into production.
>
> **Water cycle:** The cycle of water in the hydraulic fracturing process, encompassing the acquisition of water, chemical mixing of the fracturing fluid, injection of the fluid into the formation, the production and management of flowback and produced water, and the ultimate treatment and disposal of hydraulic fracturing wastewaters.

Hydraulic gradient: Slope of a water table or potentiometric surface. More specifically, change in the hydraulic head per unit of distance in the direction of the maximum rate of decrease. (2)

Hydrocarbon: An organic compound containing only hydrogen and carbon, often occurring in petroleum, natural gas, and coal. (2)

Immiscible: The chemical property where two or more liquids or phases do not readily dissolve in one another, such as soil and water. (2)

Integrated Risk Information System (IRIS): An electronic database that contains the EPA's latest descriptive and quantitative regulatory information about chemical constituents. Files on chemicals maintained in IRIS contain information related to both noncarcinogenic and carcinogenic health effects. (2)

Laboratory studies: Targeted research conducted to better understand the ultimate fate and transport of chemical contaminants of concern. The contaminants of concern may be components of hydraulic fracturing fluids, naturally occurring substances released from the subsurface during hydraulic fracturing, or treated flowback and produced water that has been released.

Mass spectrometry: Method of chemical analysis in which the substance to be analyzed is heated and placed in a vacuum. The resulting vapor is exposed to a beam of electrons that causes ionization to occur, either of the molecules or their fragments. The ionized atoms are separated according to their mass and can be identified on that basis. (2)

Material Safety Data Sheet (MSDS): Form that contains brief information regarding chemical and physical hazards, health effects, proper handling, storage, and personal protection appropriate for use of a particular chemical in an occupational environment. (2)

Monte Carlo simulation: A technique used to estimate the most probable outcomes from a model with uncertain input data and to estimate the validity of the simulated model.

National Pollution Discharge Elimination System (NPDES): A national program under Section 402 of the Clean Water Act for regulation of discharges of pollutants from point sources to waters of the United States. Discharges are illegal unless authorized by an NPDES permit. (2)

National Response Center (NRC): Communications center that receives reports of discharges or releases of hazardous substances into the environment. Run by the US Coast Guard, which relays information about such releases to the appropriate federal agency. (2)

Natural gas or **gas:** A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases in porous formations beneath the Earth's surface, often in association with petroleum. The principal constituent of natural gas is methane. (5)

Natural organic matter (NOM): Complex organic compounds that are formed from decomposing plant animal and microbial material in soil and water. (2)

Offset wells: An existing wellbore close to a proposed well that provides information for planning the proposed well. (5)

Overburden: Material of any nature, consolidated or unconsolidated, that overlies a deposit of useful minerals or ores. (2)

Peer review: A documented critical review of a specific major scientific and/or technical work product. Peer review is intended to uncover any technical problems or unresolved issues in a preliminary or draft work product through the use of independent experts. This information is then used to revise the draft so that the final work product will reflect sound technical information and analyses. The process of peer review enhances the scientific or technical work product so that the decision or position taken by the EPA, based on that product, has a sound and credible basis.

Permeability: Ability of rock to transmit fluid through pore spaces. (1)

Physicochemical properties: The inherent physical and chemical properties of a molecule such as boiling point, density, physical state, molecular weight, vapor pressure, etc. These properties define how a chemical interacts with its environment.

Play: A set of oil or gas accumulations sharing similar geologic, geographic properties, such as source rock, hydrocarbon type, and migration pathways. (1)

Porosity: Percentage of the rock volume that can be occupied by oil, gas or water. (1)

Produced water: After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracturing fluid and some is natural formation water. These produced waters move back through the wellhead with the gas. (4)

Proppant/propping agent: A granular substance (sand grains, aluminum pellets, or other material) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.

Publicly owned treatment works (POTW): Any device or system used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This definition includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment. (2)

Quality assurance (QA): An integrated system of management activities involving planning, implementation, documentation, assessment, reporting, and quality improvement to ensure that a process, item, or service is of the type and quality needed and expected by the customer. (2)

Quality assurance project plan (QAPP): A formal document describing in comprehensive detail the necessary quality assurance procedures, quality control activities, and other technical activities that need to be implemented to ensure that the results of the work performed will satisfy the stated performance or acceptance criteria. (2)

Quality Management Plan: A document that describes a quality system in terms of the organizational structure, policy and procedures, functional responsibilities of management and staff, lines of authority, and required interfaces for those planning, implementing, documenting, and assessing all activities conducted. (2)

Radionuclide: Radioactive particle, man-made or natural, with a distinct atomic weight number. Emits radiation in the form of alpha or beta particles, or as gamma rays. Can have a long life as soil or water pollutant. Prolonged exposure to radionuclides increases the risk of cancer. (2)

Residuals: The solids generated or retained during the treatment of wastewater. (2)

Safe Drinking Water Act (SDWA): The act designed to protect the nation's drinking water supply by establishing national drinking water standards (maximum contaminant levels or specific treatment techniques) and by regulating underground injection control wells. (2)

Scenario evaluation: Exploration of realistic, hypothetical scenarios related to hydraulic fracturing activities using computer models. Used to identify conditions under which hydraulic fracturing activities may adversely impact drinking water resources.

Science Advisory Board: A federal advisory committee that provides a balanced, expert assessment of scientific matters relevant to the EPA. An important function of the Science Advisory Board is to review EPA’s technical programs and research plans.

Service company: A company that assists well operators by providing specialty services, including hydraulic fracturing.

Shale: A fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock. (5)

Solubility: The amount of mass of a compound that will dissolve in a unit volume of solution. (2)

Sorption: The act of soaking up or attracting substances. (2)

Source water: Water withdrawn from surface or ground water, or purchased from suppliers, for hydraulic fracturing.

Spud (spud a well): To start the well drilling process by removing rock, dirt, and other sedimentary material with the drill bit.

Standard operating procedure (SOP): A written document that details the method of an operation, analysis, or action whose techniques and procedures are thoroughly prescribed and which is accepted as the method for performing certain routine or repetitive tasks. (2)

Statistical analysis: Analyzing collected data for the purposes of summarizing information to make it more usable and/or making generalizations about a population based on a sample drawn from that population. (2)

Surface water: All water naturally open to the atmosphere (rivers, lakes, reservoirs, ponds, streams, impoundments, seas, estuaries, etc.). (2)

Surfactant: Used during the hydraulic fracturing process to decrease liquid surface tension and improve fluid passage through the pipes.

Technical systems audit (TSA): A thorough, systematic, onsite, qualitative audit of facilities, equipment, personnel, training, procedures, record keeping, data validation, data management, and reporting aspects of a system. (2)

Tight sands: A geological formation consisting of a matrix of typically impermeable, non-porous tight sands.

Total dissolved solids (TDS): The quantity of dissolved material in a given volume of water. (2)

Toxicity reference value: A reference point (generally a dose or concentration) where exposures below that point are not likely to result in an adverse event/effect given a specific range of time.

Toxic Substances Control Act (TSCA): The act that controls the manufacture and sale of certain chemical substances. (2)

Unconventional resource: An umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as unconventional at any particular time is a complex function of resource characteristics, the available exploration and production technologies, the economic environment, and the scale, frequency, and duration of production from the resource. Perceptions of these factors inevitably change over time and often differ among users of the term. At present, the term is used in reference to oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs, and tight gas sands are considered unconventional resources. (5)

Underground Injection Control (UIC): The program under the Safe Drinking Water Act that regulates the use of wells to pump fluids into the ground. (2)

Underground injection control well: Units into which hazardous waste is permanently disposed of by injection 0.25 miles below an aquifer with an underground source of drinking water (as defined under the SDWA). (2)

Underground source of drinking water: An aquifer currently being used as a source of drinking water or containing a sufficient quantity of ground water to supply a public water system. USDWs have a total dissolved solids content of 10,000 milligrams per liter or less and are not aquifers exempted from protection under the Safe Drinking Water Act. (40 CFR 144.3) (2)

Vapor pressure: The force per unit area exerted by a vapor in an equilibrium state with its pure solid, liquid, or solution at a given temperature. Vapor pressure is a measure of a substance's propensity to evaporate. Vapor pressure increases exponentially with an increase in temperature. (2)

Viscosity: A measure of the internal friction of a fluid that provides resistance to shear within the fluid. (2)

Volatile: Readily vaporizable at a relatively low temperature. (2)

Wastewater treatment: Chemical, biological, and mechanical procedures applied to an industrial or municipal discharge or to any other sources of contaminated water in order to remove, reduce, or neutralize contaminants. (2)

Water withdrawal: The process of taking water from a source and conveying it to a place for a particular type of use. (2)

Well files: Files that generally contain information regarding all activities conducted at an oil and gas production well. These files are created by oil and gas operators.

Well operator: A company that ultimately controls and operates oil and gas wells.

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ENVIRONMENTAL IMPACTS OF HYDRAULIC FRACTURING

BY:

EARTHWORKS

Earthworks is a nonprofit organization dedicated to protecting communities and the environment from the impacts of irresponsible mineral and energy development while seeking sustainable solutions.

March 2013

ENVIRONMENTAL IMPACTS OF HYDRAULIC FRACTURING
BY EARTHWORKS

TABLE OF CONTENTS

LISTING OF FIGURES

LISTING OF TABLES

NOTES

- This document is a compilation of various portions of the Earthworks webpage. While significant re-formatting of the material has occurred to facilitate this transition, the content is consistent with the original source.
  - http://test.earthworksaction.org/index.php/issues/detail/hydraulic_fracturing_101
  - http://www.earthworksaction.org/issues/detail/inadequate_regulation_of_hydraulic_fracturing#.URJz91rjnC
  - http://test.earthworksaction.org/index.php/library/detail/protecting_health_ensuring_accountability
  - http://test.earthworksaction.org/index.php/library/detail/hydraulic_fracturing_and_the_frac_act_frequently_asked_questions
  - http://www.earthworksaction.org/library/detail/hydraulic_fracturing_myths_and_facts
- Hyperlinks are imbedded within the document and indicated by blue font color.

ENVIRONMENTAL IMPACTS OF HYDRAULIC FRACTURING
BY EARTHWORKS

1.0 Hydraulic fracturing - What it is

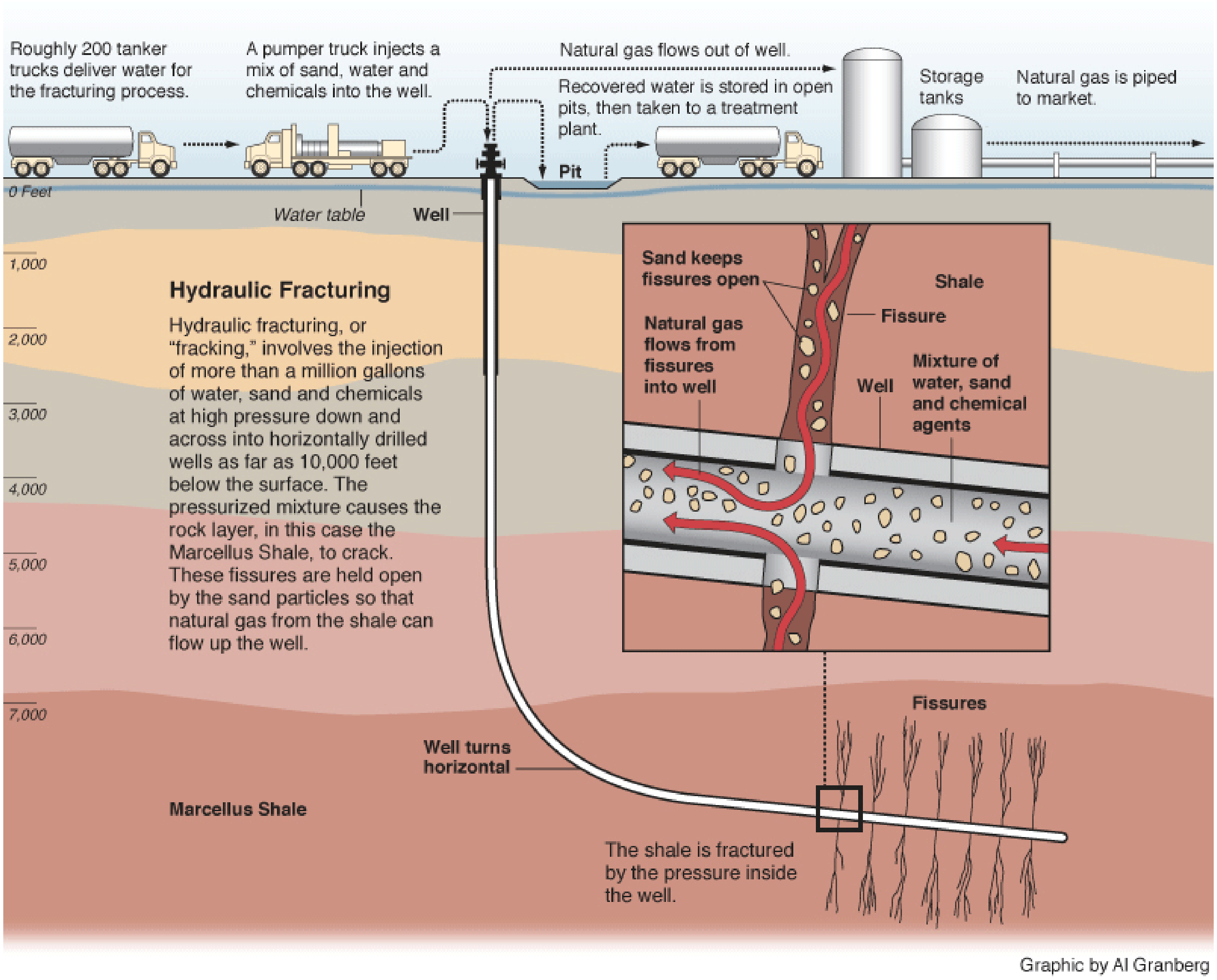


Figure 1: Overview of Hydraulic Fracturing
Source: www.ProPublica.com

Geologic formations may contain large quantities of oil or gas, but have a poor flow rate due to low permeability, or from damage or clogging of the formation during drilling. This is particularly true for tight sands, shales and coalbed methane formations.

Hydraulic fracturing (aka **fracking**, which rhymes with cracking) stimulates wells drilled into these formations, making profitable otherwise prohibitively expensive extraction. Within the past decade, the combination of hydraulic fracturing with horizontal drilling has opened up shale deposits across the country and brought large-scale natural gas drilling to new regions.

The fracking process occurs after a well has been drilled and steel pipe (casing) has been inserted in the well bore. The casing is perforated within the target zones that contain oil or gas, so that when the fracturing fluid is injected into the well it flows through the perforations into the target zones. Eventually, the target formation will not be able to absorb the fluid as quickly as it is being injected. At this point, the pressure created causes the formation to crack or fracture. Once the fractures have been created, injection ceases and the fracturing fluids begin to flow back to the surface. Materials called proppants (e.g., usually sand or ceramic beads), which were injected as part of the frac fluid mixture, remain in the target formation to hold open the fractures.

Typically, a mixture of water, proppants and chemicals is pumped into the rock or coal formation. There are, however, other ways to fracture wells. Sometimes fractures are created by injecting gases such as propane or nitrogen, and sometimes acidizing occurs simultaneously with fracturing. Acidizing involves pumping acid (usually hydrochloric acid), into the formation to dissolve some of the rock material to clean out pores and enable gas and fluid to flows more readily into the well.

Some studies have shown that anywhere from 20-85% of fracking fluids may remain underground. Used fracturing fluids that return to the surface are often referred to as flowback, and these wastes are typically stored in open pits or tanks at the well site prior to disposal.

Figure 2: Fracking operation, Grass Mesa, Colorado
Photo Credit: Peggy Utesch

2.0 Hydraulic fracturing - Issues and impacts

The process of fracturing a well is far from benign. The following sections provide an overview of some of the issues and impacts related to this well stimulation technique.

2.1 Water Use

In 2010, the U.S. Environmental Protection Agency estimated that 70 to 140 billion gallons of water are used to fracture 35,000 wells in the United States each year. This is approximately the annual water consumption of 40 to 80 cities each with a population of 50,000. Fracture treatments in coalbed methane wells use from 50,000 to 350,000 gallons of water per well, while deeper horizontal shale wells can use anywhere from 2 to 10 million gallons of water to fracture a single well. The extraction of so much water for fracking has raised concerns about the ecological impacts to aquatic resources, as well as dewatering of drinking water aquifers.

It has been estimated that the transportation of a million gallons of water (fresh or waste water) requires 200 truck trips. Thus, not only does water used for hydraulic fracturing deplete fresh water supplies and impact aquatic habitat, the transportation of so much water also creates localized air quality, safety and road repair issues.

2.2 Sand and Proppants

Conventional oil and gas wells use, on average, 300,000 pounds of proppant, coalbed fracture treatments use anywhere from 75,000 to 320,000 pounds of proppant and shale gas wells can use more than 4 million pounds of proppant per well.

Frac sand mines are springing up across the country, from Wisconsin to Texas, bringing with them their own set of impacts. Mining sand for proppant use generates its own range of impacts, including water consumption and air emissions, as well as potential health problems related to crystalline silica.

2.3 Toxic Chemicals

In addition to large volumes of water, a variety of chemicals are used in hydraulic fracturing fluids. The oil and gas industry and trade groups are quick to point out that chemicals typically make up just 0.5 and 2.0% of the total volume of the fracturing fluid. When millions of gallons of water are being used, however, the amount of chemicals per fracking operation is very large. For example, a four million gallon fracturing operation would use from 80 to 330 tons of chemicals.[1]

As part of New York State's Draft Supplemental Generic Environmental Impact Statement (SGEIS) related to Horizontal Drilling and High-Volume Hydraulic Fracturing in the Marcellus Shale, the Department of Environmental Conservation complied a list of chemicals and additives used during hydraulic fracturing. The table below provides examples of various types of hydraulic fracturing additives proposed for use in New York. Chemicals in brackets [ ] have not been proposed for use in the state, but are known to be used in other states or shale formations.

Table 1: Hydraulic Fracturing Additives Proposed for Use in New York

ADDITIVE TYPE	DESCRIPTION OF PURPOSE	EXAMPLES OF CHEMICALS
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / Biocide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2-Bromo-2-nitro-1,2-propanediol
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers.	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride) [Potassium chloride]
Corrosion Inhibitor	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulfate for Oxygen Scavengers
Crosslinker	The fluid viscosity is increased using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity	Potassium hydroxide; borate salts

	allows the fluid to carry more proppant into the fractures.	
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum; petroleum distillate
Iron Control	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol; polyacrylate
Solvent	Additive which is soluble in oil, water & acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol; ethoxylated alcohol

Many fracturing fluid chemicals are known to be toxic to humans and wildlife, and several are known to cause cancer. Potentially toxic substances include petroleum distillates such as kerosene and diesel fuel (which contain benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals); polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide.

Very small quantities of some fracking chemicals are capable of contaminating millions of gallons of water. According to the Environmental Working Group, petroleum-based products known as petroleum distillates such as kerosene (also known as hydrotreated light distillates, mineral spirits, and a petroleum distillate blends) are likely to contain benzene, a known human carcinogen that is toxic in water at levels greater than five parts per billion (or 0.005 parts per million).

Other chemicals, such as 1,2-Dichloroethane are volatile organic compounds (VOCs). Volatile organic constituents have been shown to be present in fracturing fluid flowback wastes at levels that exceed drinking water standards. For example, testing of flowback samples from Pennsylvania have revealed concentrations of 1,2-Dichloroethane as high as 55.3 micrograms per liter, which is more than 10 times EPA's Maximum Contaminant Level for 1,2-Dichloroethane in drinking water.

VOCs not only pose a health concern while in the water, the volatile nature of the constituents means that they can also easily enter the air. According to researchers at the University of Pittsburgh's Center for Healthy Environments and Communities, organic compounds brought to the surface in the fracturing flowback or produced water often go into open impoundments (frac ponds), where the volatile organic chemicals can offgas into the air.

When companies have an excess of unused hydraulic fracturing fluids, they either use them at another job or dispose of them. Some Material Safety Data Sheets (MSDSs) include information on disposal options for fracturing fluids and additives. The table below summarizes the disposal considerations that the company Schlumberger Technology Corp. ("Schlumberger") includes in its MSDSs.[2]

Table 2: Hydraulic Fracturing Fluids or Additive Recommended Disposal Methods

Hydraulic Fracturing Fluids or Additive	Recommended Disposal
Foaming Agent F104 Corrosion Inhibitor A186 Organic Acid L36 Chelating Agent Liquid Breaker Aid J318 Breaker J218 Biocide B59 PSG Polymer Slurry J877	Hazardous waste disposal facility
Water Gelling Agent J424	Hazardous waste landfill, incineration, or sanitary landfills in some jurisdictions
Potassium Chloride M117	Hazardous waste landfill. Material may be acceptable in some landfills.
Coalbed Methane Additive J473	Incineration, disposal well injection, or other acceptable methods according to local regulations
Borate Crosslinker J532	Inject in disposal well. Small amounts may be acceptable in sanitary sewer
Gelling Agent U28	Neutralized material is generally acceptable in sanitary sewers

As seen in the table, Schlumberger recommends that many fracturing fluid chemicals be disposed of at hazardous waste facilities. Yet these same fluids (in diluted form) are allowed to be injected directly into or adjacent to USDWs. Under the *Safe Drinking Water Act*, hazardous wastes may not be injected into USDWs. Moreover, even if hazardous wastes are decharacterized (for example, diluted with water so that they are rendered non-hazardous), wastes must still be injected into a formation that is below the USDW.

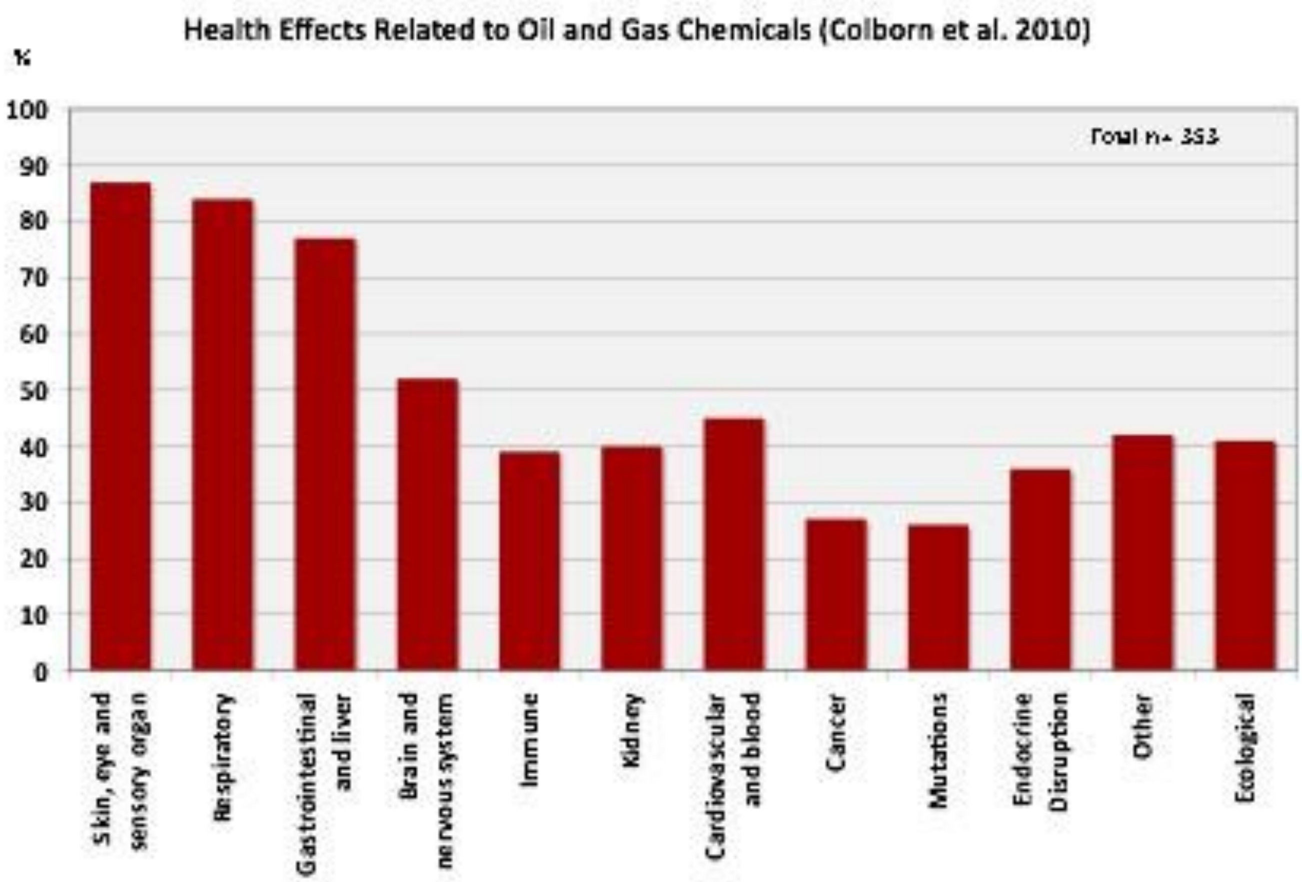
Clearly, some hydraulic fracturing fluids contain chemicals deemed to be "hazardous wastes." Even if these chemicals are diluted it is unconscionable that EPA is allowing these substances to be injected directly into underground sources of drinking water.

2.4 Health Concerns

Human exposure to fracking chemicals can occur by ingesting chemicals that have spilled and entered drinking water sources, through direct skin contact with the chemicals or wastes (e.g., by workers, spill responders or health care professionals), or by breathing in vapors from flowback wastes stored in pits or tanks.

In 2010, Theo Colborn and three co-authors published a paper entitled *Natural Gas Operations from a Public Health Perspective*. Colborn and her co-authors summarized health effect information for 353 chemicals used to drill and fracture natural gas wells in the United States. Health effects were broken into 12 categories: skin, eye and sensory organ, respiratory, gastrointestinal and liver, brain and nervous system, immune, kidney, cardiovascular and blood, cancer, mutagenic, endocrine disruption, other, and ecological effects. The chart below illustrates the possible health effects associated with the 353 natural gas-related chemicals for which Colborn and her co-authors were able to gather health-effects data.

Figure 3:



Colborn's paper provides a list of 71 particularly nasty drilling and fracturing chemicals, i.e., those that are associated with 10 or more health effects.

Table 3: Natural Gas Drilling and Hydraulic Fracturing Chemicals with 10 or More Health Effects

- 2,2',2"-Nitrilotriethanol
- 2-Ethylhexanol
- 5-Chloro-2-methyl-4-isothiazolin-3-one
- Acetic acid
- Acrolein
- Acrylamide (2-propenamide)
- Acrylic acid
- Ammonia
- Ammonium chloride
- Ammonium nitrate
- Aniline
- Benzyl chloride
- Boric acid
- Cadmium
- Calcium hypochlorite
- Chlorine
- Chlorine dioxide
- Dibromoacetonitrile 1
- Diesel 2
- Diethanolamine
- Diethylenetriamine
- Dimethyl formamide
- Epidian
- Ethanol (acetylenic alcohol)
- Ethyl mercaptan
- Ethylbenzene
- Ethylene glycol
- Ethylene glycol monobutyl ether (2-BE)
- Ethylene oxide
- Ferrous sulfate
- Formaldehyde
- Formic acid
- Fuel oil #2
- Glutaraldehyde
- Glyoxal
- Hydrodesulfurized kerosene
- Hydrogen sulfide
- Iron
- Isobutyl alcohol (2-methyl-1-propanol)
- Isopropanol (propan-2-ol)
- Kerosene
- Light naphthenic distillates, hydrotreated
- Mercaptoacidic acid
- Methanol
- Methylene bis(thiocyanate)
- Monoethanolamine
- NaHCO3
- Naphtha, petroleum medium aliphatic
- Naphthalene
- Natural gas condensates
- Nickel sulfate
- Paraformaldehyde
- Petroleum distillate naptha
- Petroleum distillate/naphtha
- Phosphonium, tetrakis(hydroxymethyl)-sulfate
- Propane-1,2-diol
- Sodium bromated
- Sodium chlorite (chlorous acid, sodium salt)
- Sodium hypochlorite
- Sodium nitrate
- Sodium nitrite
- Sodium sulfite
- Styrene
- Sulfur dioxide
- Sulfuric acid
- Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (Dazomet)
- Titanium dioxide
- Tributyl phosphate
- Triethylene glycol
- Urea
- Xylene

While Colborn and her co-workers focused on chemicals used in natural gas development, the chemicals used to fracture oil wells are very similar or the same. Looking at some of the oil wells that have been developed in the Bakken Shale in North Dakota, the fracturing fluid mixtures include some of the chemicals shown by Colborn to have the potential to cause 10 or more adverse health effects. Information posted hydraulic fracturing fluid chemicals on the FracFocus web site indicates that Bakken Shale oil wells may contain toxic chemicals such as hydrotreated light distillate, methanol, ethylene glycol, 2-butoxyethanol (2-BE), phosphonium, tetrakis(hydroxymethyl)-sulfate (aka phosphonic acid), acetic acid, ethanol, and napthlene.[3]

2.5 Surface Water and Soil Contamination

Spills of fracturing chemicals and wastes during transportation, fracturing operations and waste disposal have contaminated soil and surface waters. This section provides a few examples of spills related to hydraulic fracturing that have led to environmental impacts.

- **Two spills kill fish:** In September 2009, Cabot Oil and Gas spilled hydraulic fracturing fluid gel LGC-35 twice at the company's Heitsman gas well. The two incidents released a total of 8,000 gallons of the fracturing fluid, polluting Stevens Creek and resulting in a fish kill. LGC-35, a well lubricant used during the fracturing process. A third spill of LGC-35 occurred a week later, but did not enter the creek.
- **Fracturing fluid taints a high quality watershed:** In December 2009, a wastewater pit overflowed at Atlas Resources' Cowden 17 gas well, and an unknown quantity of hydraulic fracturing fluid wastes entered Dunkle Run, a "high quality watershed". The company failed to report the spill. In August 2010 the Pennsylvania Department of Environmental Protection (DEP) levied a $97,350 fine against Atlas Resources
- **Another fracturing fluid spill impacts a high quality waterway:** In May 2010, Range Resources was fined was fined $141,175 for failing to immediately notify the Pennsylvania Department of Environmental Protection when the company spilled 250 barrels of diluted fracturing fluids due to a broken joint in a transmission line. The fluids flowed into an unnamed tributary of Brush Run, killing at least 168 fish, salamanders and frogs. The watercourse is designated as a warm-water fishery under Pennsylvania's special protection waters program.
- **Fracturing fluids affect soil and irrigation ditch:** In October 2005 a valve on the wellhead of a Kerr-McGee well in Colorado failed. As a result, between168 and 210 gallons of flowback fluids sprayed into the air and drifted offsite, primarily onto pasture land, resulting in a visible coating that was as much as 1/2 inch thick.

2.6 Groundwater Contamination

As mentioned previously, hydraulic fracturing is used in many coalbed methane (CBM) production areas. Some coal beds contain groundwater of high enough quality to be considered underground sources of drinking water (USDWs).

Table 4: Chemicals in Fracking Fluids

Product	Chemical Composition of Existing Products	Concentration of Interest (µg/L)	
	Chemical Compound	Point-of-Injection	MCL, RBC or *MCP*
Linear gel delivery system	guar gum derivative		
	diesel, which contains the following:		
	benzene	313.20	5.00
	toluene	522.00	1,000.00
	ethylbenzene	522.00	700.00
	xylene	522.00	10,000.00
	naphthalene	14,094.00	20.00
	1-methylnapthalene	71,340.00	***20 / 6,000***
	2-methylnapthalene	34,974.00	121.67
	dimethylnapthalenes	270,570.00	na
	trimethylnapthalenes	160,080.00	na
	fluorenes	31,320.00	2190.00
	phenanthrenes	7,830.00	***300 / 50***
	aromatics	574,200.00	***200 / 30,000***
Water Gelling Agent	guar gum		
	water	495,049.50	na
	fumaric acid	132,337.87	na
Linear Gel Polymer	fumaric acid	529,351.49	na
	adipic acid	366,257.43	na
Gelling Agents (BLM Lists)	benzene		5.00
	ethylbenzene		700.00
	methyl tert-butyl ether		2.64
	naphthalene		20.00
	polynuclear aromatic hydrocarbons (pahs)		na
	polycyclic organic matter (pom)		na
	sodium hydroxide		na
	toluene		1,000.00
	xylene		10,000.00
Crosslinker	boric acid	170,998.00	na
	ethylene glycol	285,788.42	73,000.00
	monoethanolamine	na	na
Crosslinker	sodium tetraborate decahydrate		na
Crosslinker (BLM Lists)	ammonium chloride		na
	potassium hydroxide		na
	zirconium nitrate		na
	zirconium sulfate		na
Foaming Agent	isopropanol	234,945.16	na
	salt of alkyl amines	na	na
	diethanolamine	na	na
Foaming Agent	ethanol	236,081.75	na
	2-butoxyethanol	269,641.08	na
	ester salt	na	na
	polyglycol ether	na	na
	water		na
Foamers (BLM)	glycol ethers	na	na
Acid Treatment	hydrochloric acid	na	na
Acid Treatment	formic acid	na	73,000.00
Breaker Fluid	diammonium peroxidisulfate	na	na
Breaker Fluids (BLM Lists)	ammonium persulfate		na
	ammonium sulfate		na
	copper compounds		1,460.00
	ethylene glycol		na
	glycol ethers		na
Microbiocide	2-bromo-2nitrol,3-propanediol		na
Biocide	2,2-dibromo-3-nitrilopropionamide		na
	2-bromo-3-nirtrilopropionamide		na
Bactericides	polycyclic organic matter (pom)		na
	polynuclear aromatic hydrocarbons (pahs)		na
Acid Corrosion Inhibitor	methanol	236,070,000.00	18,250.00
	propargyl alcohol	47,425,000.00	na
Acid Corrosion Inhibitor	pyridinium, 1-(phenylmethyl)-,ethyl methyl deriv.	na	na
	thiourea	210,750,000.00	na
	propan-2-ol	39,275,000.00	na
	poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy	na	na

= Exceeds regulatory standard

MCL = Maximum Contaminant Level - The highest level of a contaminant that is allowed in drinking water.

RBC = EPA's Risk Based Concentration Tables. (http://www.epa.gov/reg3hwmd/risk/index.html, developed by Region 3, serving: Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia)

MCP = Massachusetts Contingency Plan - Risk-based ground water standards for drinking water protection chosen because Massachusetts has developed standards for many constituents in diesel fuel. Two numbers are given (the first is drinking water standard, the second is standard for groundwater discharging to surface water).

Source: EPA

In 2004, the U.S. Environmental Protection Agency (EPA) released a final study on Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. In the study, EPA found that ten out of eleven CBM basins in the U.S. are located, at least in part, within USDWs. Furthermore, the EPA determined that in some cases, hydraulic fracturing chemicals are injected directly into USDWs during the course of normal fracturing operations. (Read Laura Amos's story to learn how hydraulic fracturing has affected her family's life.)

Calculations performed by EPA in the draft version of its study show that at least nine hydraulic fracturing chemicals may be injected into or close to USDWs at concentrations that pose a threat to human health. The chart below is a reproduction of the data from the EPA draft study. As seen in the chart, chemicals may be injected at concentrations that are anywhere from 4 to almost 13,000 times the acceptable concentration in drinking water.

Not only does the injection of these chemicals pose a short-term threat to drinking water quality, it is quite possible that there could be long-term negative consequences for USDWs from these fracturing fluids. According to the EPA study, studies conducted by the oil and gas industry, and interviews with industry and regulators, 20 to 85% of fracturing fluids may remain in the formation, which means the fluids could continue to be a source of groundwater contamination for years to come.

The potential long-term consequences of dewatering and hydraulic fracturing on water resources have been summed up by professional hydrogeologist who spent 32 years with the U.S. Geological Survey:

> *At greatest risk of contamination are the coalbed aquifers currently used as sources of drinking water. For example, in the Powder River Basin (PRB) the coalbeds are the best aquifers. CBM production in the PRB will destroy most of these water wells; BLM predicts drawdowns...that will render the water wells in the coal unusable because the water levels will drop 600 to 800 feet. The CBM production in the PRB is predicted to be largely over by the year 2020. By the year 2060 water levels in the coalbeds are predicted to have recovered to within 95% of their current levels; the coalbeds will again become useful aquifers. However, contamination associated with hydrofracturing in the basin could threaten the usefulness of the aquifers for future use.*

As mentioned previously, anywhere from 20-85% of fracking fluids remain in the ground. Some fracturing gels remain stranded in the formation, even when companies have tried to flush out the gels using water and strong acids. Also, studies show that gelling agents in hydraulic fracturing fluids decrease the permeability of coals, which is the opposite of what hydraulic fracturing is supposed to do (i.e., increase the permeability of the coal formations). Other similar, unwanted side effects from water- and chemical-based fracturing include: solids plugging up the cracks; water retention in the formation; and chemical reactions between the formation minerals and stimulation fluids. All of these cause a reduction in the permeability in the geological formations.

For more details on the studies that have looked at stranded fracturing fluids and the potential for hydraulic fracturing to affect underground sources of drinking water, see *Our Drinking Water at Risk*, Oil and Gas Accountability Project's review of the EPA's study on the impacts of hydraulic fracturing of coalbed methane reservoirs on drinking water.

2.7 Air Quality

In many oil and gas producing regions, there has been a degradation of air quality as drilling increases. For example, in Texas, high levels of benzene have been measured in the air near wells in the Barnett Shale gas fields. These volatile air toxics may be originating from a variety of gas-field source such as separators, dehydrators, condensers, compressors, chemical spills, and leaking pipes and valves.

Increasingly, research is being conducted on the potential air emissions released during the fracturing flow back stage, when wastewater returns to the surface. Shales contain numerous organic hydrocarbons, and additional chemicals are injected underground during shale gas drilling, well stimulation (e.g., hydraulic fracturing), and well workovers.

The Pittsburgh University Center for Healthy Environments and Communities (CHEC) has been examining how organic compounds in the shale can be mobilized during fracturing and gas extraction processes. According to the CHEC researchers, these organic compounds are brought to the surface in the fracturing flowback or produced water, and often go into open impoundments (frac ponds), where the waste water, "will offgas its organic compounds into the air. This becomes an air pollution problem, and the organic compounds are now termed Hazardous Air Pollutants (HAP's)."

The initial draft of the New York draft supplemental environmental impacts statement related to drilling in the Marcellus Shale (which is no longer available on-line) included information on modeling of potential air impacts from fracturing fluid wastes stored in centralized impoundments. One analysis looked at the volatile organic compound methanol, which is known to be present in fracturing fluids such as surfactants, cross-linkers, scale inhibitors and iron control additives. The state calculated that a centralized fracturing flowback waste impoundment serving 10 wells (5 million gallons of flowback per well) could have an annual emission of 32.5 tons of methanol.

The U.S. EPA reports that "chronic inhalation or oral exposure to methanol may result in headache, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, visual disturbances (blurred vision), and blindness in humans."

Open pits, tanks or impoundments that accept flowback wastes from one well would have a much smaller emission of volatile organic compounds (VOC) like methanol than facilities accepting wastes from multiple wells. But there are centralized flowback facilities like those belonging to Range Resources in Washington County, Pennsylvania that have been designed for "long-term use," and thus, are likely to accept wastes from more than one well.

New York's air modeling further suggested that the emission of Hazardous Air Pollutants (HAPs) from centralized flowback impoundments could exceed ambient air thresholds 1,000 meters (3,300 feet) from the impoundment, and could cause the impoundment to qualify as a major source of HAPs.

Methanol is just one of the VOCs contained in flowback water. The combined emissions from all VOCs present in flowback stored at centralized impoundments could be very large, depending on the composition of the fracturing fluids used at the wells. Data released on flowback water from wells in Pennsylvania reveal that numerous volatile organic chemicals are returning to the surface, sometime in high concentrations. The Pennsylvania Department of Environmental Protection looked for 70 volatile organic compounds in flowback, and 27 different chemicals showed up.

In a health effects analysis conducted by Theo Colborn and others, 37% of the chemicals used during natural gas drilling, fracturing and production (for which health data were available) were found to be volatile, with the ability to become airborne. Colborn and her co-authors compared the potential health impacts of volatile chemicals with those chemicals more like to be found in water (i.e., chemicals with high solubilities). They found that "far more of the volatile chemicals (81%) can cause harm to the brain and nervous system. Seventy one percent of the volatile chemicals can harm the cardiovascular system and blood, and 66% can harm the kidneys," producing a profile that "displays a higher frequency of health effects than the water soluble chemicals." The researchers add that the chance of exposures to volatile chemicals are increased by case they can be inhaled, ingested and absorbed through the skin. Citizens of the gas field are experiencing health effects related to volatile chemicals from pits.

- In 2005, numerous Colorado residents experienced severe odors and health impacts related to flowback and drilling pits and tanks in Garfield County. According to Dion and Debbie Enlow complained to the Colorado Oil and Gas Conservation Commission about odors from a Barrett wellpad upwind from their home. The pad had four wells that were undergoing completion/hydraulic fracturing. Dion Enlow complained to the company that the smell was so bad that "I can't go outside and breathe."
- In Pennsylvania, a fracturing flowback wastewater pit just beyond June Chappel's property line created odors similar to gasoline and kerosene, which forced her inside, left a greasy film on her windows, on one occasion created a white dust that fell over her yard. Chappel and her neighbors lived with the noxious odors until they hired an attorney and Range Resources agreed to remove the impoundment.
- In March 2010, a fracturing flowback wastewater impoundment in Washington County, Pennsylvania caught fire and exploded producing a cloud of thick, black smoke that could be seen miles away. For several days prior to the explosion nearby citizens had tried to alert state officials about noxious odors from the impoundment that were sickening their families, but "their voicemail boxes were full."

2.8 Waste Disposal

It has been reported that anywhere from 25 – 100% of the chemical-laced hydraulic fracturing fluids return to the surface from Marcellus Shale operations. This means that for some shale gas wells, millions of gallons of wastewater are generated, and require either treatment for re-use, or disposal.

In 2009, the volume of fracturing flowback and brines produced in Pennsylvania was estimated to be 9 million gallons of wastewater per day, and this figure was expected to increase to 19 - 20 million gallons/day in 2011.

The sheer volume of wastes, combined with high concentrations of certain chemicals in the flowback from fracturing operations, are posing major waste management challenges for the Marcellus Shale states. Also, the US Geological Survey has found that flowback may contain a variety of formation materials, including brines, heavy metals, radionuclides, and organics, which can make wastewater treatment difficult and expensive.

According to an article in *ProPublica*, New York City's Health Department has raised concerns about the concentrations of radioactive materials in wastewater from natural gas wells. In a July, 2009 letter obtained by ProPublica, the Department wrote that "Handling and disposal of this wastewater could be a public health concern." The letter also mentioned that the state may have difficulty disposing of the waste, that thorough testing will be needed at water treatment plants, and that workers may need to be monitored for radiation as much as they might be at nuclear facilities.

Options for disposal of radioactive flowback or produced water include underground injection in Class II UIC wells and offsite treatment. The U.S. Environmental Protection Agency has indicated that Class II UIC injection disposal wells are uncommon in New York, and existing wells aren't licensed to receive radioactive waste. In terms of offsite treatment, it is not known if any of New York's water treatment facilities are capable of handling radioactive wastewater. *ProPublica* contacted several plant managers in central New York who said they could not take the waste or were not familiar with state regulations.

Pennsylvania state regulators and the natural gas industry are also facing challenges regarding how to ensure proper disposal of the millions of gallons of chemical-laced wastewater generated daily from hydraulic fracturing and gas production in the Marcellus shale.

Drinking water treatment facilities in Pennsylvania are not equipped to treat and remove many flowback contaminants, but rather, rely on dilution of chlorides, sulfates and other chemicals in surface waters used for drinking water supplies.

During the fall of 2008, the disposal of large volumes of flowback and produced water at publicly owned treatment works (POTWs) contributed to high total dissolved solids (TDS) levels measured in Pennsylvania's Monongahela River and its tributaries. Studies showed that in addition to the Monongahela River, many of the other rivers and streams in Pennsylvania had a very limited ability to assimilate additional TDS, sulfate and chlorides, and that the high concentrations of these constituents were harming aquatic communities. Research by Carnegie Mellon University and Pittsburgh Water and Sewer Authority experts suggests that the natural gas industry has contributed to elevated levels of bromide in the Allegheny and Beaver Rivers. Bromides react with disinfectants used by municipal treatment plants to create brominated trihalomethanes, which have been linked to several types of cancer and birth defects.

In August of 2010, Pennsylvania enacted new rules limiting the discharge of wastewater from gas drilling to 500 milligrams per liter of total dissolved solids (TDS) and 250 milligrams per liter for chlorides. The number of municipal facilities allowed to take drilling and fracking wastewater has dropped from 27 in 2010 to 15 in 2011.

Disposal of drilling and fracking waste water is going to continue to present a challenge to local and state governments as more wells are developed across the country.

2.9 Chemical Disclosure

One potentially frustrating issue for surface owners is that it has not been easy to find out what chemicals are being used during the hydraulic fracturing operations in your neighborhood. According to the Natural Resources Defense Council, in the late 1990s and early 2000s attempts by various environmental and ranching advocacy organizations to obtain chemical compositions of hydraulic fracturing fluids were largely unsuccessful because oil and gas companies refused to reveal this "proprietary information."

In the mid-2000s, the Oil and Gas Accountability Project and The Endocrine Disruption Exchange (TEDX) began to compile information on drilling and fracturing chemicals from a number of sources, including Material Safety Data Sheets obtained through Freedom of Information Act requests of state agencies. TEDX subsequently produced reports on the toxic chemicals used in oil and gas development in several western states including Montana, New Mexico, Wyoming and Colorado, and worked with the Environmental Working Group to produce a report on chemicals injected into oil and gas wells in Colorado.

In 2006, the first effort to require disclosure of chemicals was launched. In June of 2006, the Oil and Gas Accountability Project submitted a letter to the Colorado Oil and Gas Conservation Commission (COGCC) and the Colorado Department of Public Health and the Environment (CDPHE) on behalf of five citizens organizations in Colorado. The groups asked that state agencies require disclosure of the chemicals used and monitoring of chemicals and wastes released by the oil and gas industry in Colorado. Since that time the Oil and Gas Accountability Project and others have worked to get disclosure bills passed in states across the country. Wyoming, Arkansas, Pennsylvania, Michigan and Texas now require a certain level of disclosure, although trade secret laws still prevent full disclosure in most states.

2.10 Hydraulic Fracturing Best Practices

From a public health perspective, if hydraulic fracturing stimulation takes place, the best option is to fracture formations using sand and water without any additives, or sand and water with non-toxic additives. Non-toxic additives are being used by the offshore oil and gas industry, which has had to develop fracturing fluids that are non-toxic to marine organisms.

It is common to use diesel in hydraulic fracturing fluids. This should be avoided, since diesel contains the carcinogen benzene, as well as other harmful chemicals such as naphthalene, toluene, ethylbenzene and xylene.

According to the company Halliburton, "Diesel does not enhance the efficiency of the fracturing fluid; it is merely a component of the delivery system." It is technologically feasible to replace diesel with non-toxic "delivery systems," such as plain water. According to the EPA, "Water-based alternatives exist and from an environmental perspective, these water-based products are preferable."

Oil and gas wastes are often flowed back to and stored in pits on the surface. Often these pits are unlined. But even if they are lined, the liners can tear and contaminate soil and possibly groundwater with toxic chemicals. (Read more about pits.)

As mentioned above, toxic chemicals are used during hydraulic fracturing operations. The same chemicals that are injected come back to the surface in the flowed-back wastes. As well, hydrocarbons from the fractured formation may flow back into the waste pits. A preferable way of storing wastes would be to flow them back into steel tanks.

3.0 Tips for Landowners

Obtaining fracking chemical information: The law requires that all employees have access to a Material Safety Data Sheet (MSDS), which contains information on health hazards, chemical ingredients, physical characteristics, control measures, and special handling procedures for all hazardous substances in the work area. The MSDSs are produced and distributed by the chemical manufacturers and distributors. It should be noted that MSDSs may not list all of the chemicals or chemical constituents being used (if they are trade secrets). Landowners may be able to obtain copies of MSDSs from company employees, the chemical manufacturers, or possibly from state agency representatives.

Prior to the enactment of some state laws regarding the disclosure of hydraulic fracturing and other drilling chemicals, there were two sources of information on chemicals used during oil and gas development. These sources were: Material Safety Data Sheets and Tier II reports. Now, limited chemical information can be obtained, as well, via web sites such as Frac Focus or state agency sites. But criticisms have been raised regarding fracturing fluid registries, such as they do not provide enough detailed information on chemical concentrations and volumes, nor do they provide information in a format that is easy to use.

- Matearial Safety Data Sheets (MSDSs): The law requires that all employees have access to Material Safety Data Sheets, which contain information on health hazards, chemical ingredients, physical characteristics, control measures, and special handling procedures for all hazardous substances in the work area. MSDSs are produced and distributed by the chemical manufacturers and distributors. Citizens may be able to obtain copies of MSDSs from company employees, chemical manufacturers, local or state agency representatives, or via some web sites.
- Tier II Reports: The federal Emergency Planning and Community Right-to-Know Act (EPCRA) requires facilities that store chemicals to report products that contain hazardous substances. Some chemicals do not have to be reported, if they are below a certain threshold.

Theo Colborn of The Endocrine Disruption Exchange has enumerated several problems with the information in MSDS and Tier II reports.

MSDSs and Tier II reports are fraught with gaps in information about the formulation of the products. The U.S. Occupational Safety and Health Administration (OSHA) provides only general guidelines for the format and content of MSDSs. The manufacturers of the products are left to determine what information is revealed on their MSDSs. The forms are not submitted to OSHA for review unless they are part of an inspection under the Hazard Communication Standard (U.S. Department of Labor 1998). Some MSDSs report little to no information about the chemical composition of a product. Those MSDSs that do may only report a fraction of the total composition, sometimes less than 0.1%. Some MSDSs provide only a general description of the content, such as "plasticizer", "polymer", while others describe the ingredients as "proprietary" or just a chemical class. Under the present regulatory system all of the above "identifiers" are permissible. Consequently, it is not surprising that a study by the U.S. General Accounting Office (1991) revealed that MSDSs could easily be inaccurate and incomplete. Tier II reports can be similarly uninformative, as reporting requirements vary from state to state, county to county, and company to company. Some Tier II forms include only a functional category name (e.g., "weight materials" or "biocides") with no product name. The percent of the total composition of the product is rarely reported on these forms.

4.0 The "Halliburton Loophole" and the "FRAC Act"

Despite the widespread use of the practice, and the risks hydraulic fracturing poses to human health and safe drinking water supplies, the U.S. Environmental Protection Agency ("EPA") does not regulate the injection of fracturing fluids under the Safe Drinking Water Act.

The oil and gas industry is the only industry in America that is allowed by EPA to inject known hazardous materials -- unchecked -- directly into or adjacent to underground drinking water supplies.

This exemption from the SDWA has become known as the "Halliburton loophole" because it is widely perceived to have come about as a result of the efforts of Vice President Dick Cheney's Energy Task Force. Before taking office, Cheney was CEO of Halliburton -- which patented hydraulic fracturing in the 1940s, and remains one of the three largest manufacturers of fracturing fluids. Halliburton staff were actively involved in review of the 2004 EPA report on hydraulic fracturing.

4.1 State regulation

Several oil and gas producing states have regulations governing some aspects of hydraulic fracturing, but they rarely, if ever, do they require companies to provide detailed information on types and quantities of chemicals being used, and whether the amount injected underground returns to the surface or remains underground.

Additionally, in most states companies do not have to prove that fractures have stayed within the target formations. Nor do companies have to monitor water quality when there are drinking water formations in close proximity to areas where hydraulic fracturing occurs.

4.2 The History of Federal Regulation

In 1997, the U.S. Court of Appeals for the 11th Circuit (Atlanta) ordered the EPA to regulate hydraulic fracturing under the Safe Drinking Water Act. This decision followed a 1989 CBM fracturing operation in Alabama that landowners say contaminated a residential water well.

In 2000, in response to the 1997 court decision, the EPA initiated a study of the threats to water supplies associated with the fracturing of coal seams for methane production. The primary goal of the study was to assess the potential for fracturing to contaminate underground drinking water supplies.

Meanwhile, in 2001, a special task force on energy policy convened by Vice President Dick Cheney recommended that Congress exempt hydraulic fracturing from the Safe Drinking Water Act.

The EPA completed its study in 2004, finding that fracturing "poses little or no threat" to drinking water. The EPA also concluded that no further study of hydraulic fracturing was necessary.

The 2004 EPA study has been called "scientifically unsound" by EPA whistleblower Weston Wilson. In an October 2004 letter to Colorado's congressional delegation, Wilson recommended that EPA continue investigating hydraulic fracturing and form a new peer review panel that would be less heavily weighted with members of the regulated industry. In March of 2005, EPA Inspector General Nikki Tinsley found enough evidence of potential mishandling of the EPA hydraulic fracturing study to justify a review of Wilson's complaints.

The Oil and Gas Accountability Project (OGAP) has conducted a review of the EPA study. As reported in *Our Drinking Water at Risk*, we found that EPA removed information from earlier drafts that suggested unregulated fracturing poses a threat to human health, and that the Agency did not include information that suggests fracturing fluids may pose a threat to drinking water long after drilling operations are completed.

OGAP's review of relevant data on hydraulic fracturing suggests that there is insufficient information for EPA to have concluded that hydraulic fracturing does not pose a threat to drinking water.

4.3 Efforts to Close the Halliburton Loophole

In 2005, a national energy bill included the exemption of hydraulic fracturing from the Safe Drinking Water Act. This bill passed, with the exemption, although it left the door open for the EPA to regulate the use of diesel in hydraulic fracturing operations.

Representatives DeGette, Salazar and Hinchey, and Senators Casey and Schumer have introduced legislation to protect drinking water from oil and gas development -- including ending hydraulic fracturing's exemption to the Safe Drinking Water Act.

H.R. 1084 and S. 587, the Fracking Responsibility and Awareness of Chemicals Act (FRAC Act), would close the Halliburton loophole and require oil and gas companies to disclose the chemicals they use during the fracking process. As a result, the EPA would be able to regulate hydraulic fracturing and oil and gas companies would be required to publicly disclose the types, amounts, and combinations of chemicals they use in their hydraulic fracturing processes.

By requiring full, public disclosure of the chemicals used in the hydraulic fracturing process, the FRAC Act would give regulatory agencies and the public—including the people living near and directly impacted by oil and gas operations—the information they need to conduct comprehensive water testing and trace potential contamination. Without this information, oil and gas companies can continue to deny potential links between their activities and water contamination and, as a result, avoid liability for damage caused. And under the FRAC Act, companies would be allowed ¬to keep specific proprietary formulas secure except in cases of a health-related emergency.

In addition, oil and gas companies would be required to apply for a permit from EPA before they inject chemicals near drinking water supplies. The oil and gas industry already complies with the SDWA for other processes, such as when they inject waste fluids after a well has been completed. The industry has already obtained approval for more than 150,000 injection wells including wells used to inject waste fluids from drilling such as fracturing fluids to ensure that these fluids do not pollute underground sources of drinking water.

4.4 A well-regulated industry

Passing the FRAC Act is a critical step toward ensuring that oil and gas drilling in the United States occurs in the cleanest, safest, and most responsible manner possible. Federal regulatory changes are needed to ensure that drinking water, streams, rivers, wildlife, and the air we breathe are not polluted by dirty drilling practices.

While some states are stepping up and adopting chemical disclosure laws and other regulations on oil and gas production, these standards—and the protections they offer communities and the environment—vary widely. For this reason, a federal minimum standard is needed to prevent harm from occurring in the more than 30 oil and gas producing states.

4.5 Hydraulic Fracturing and the FRAC Act: Frequently Asked Questions

<u>What are the concerns about hydraulic fracturing?</u>

Hydraulic fracturing fluids can contain a variety of toxic chemicals such as diesel fuel, acids, and acetone. Though industry proponents of the practice assert that only a small fraction of the fluid volume used in any fracturing operation consists of chemicals, because of the large volume of fluids needed for each "frack job"—sometimes millions of gallons—the chemical components of fracturing fluid can amount to tens of thousands of gallons.

Hundreds of different types of chemicals are used in fracturing operations, many of which can cause serious health problems—some are also known carcinogens.

After hydraulic fracturing takes place, both the waste fluid that is brought back to the surface as "flowback" as well as the fluids that remain underground can contain toxic substances that may come from the fracturing fluids. In addition, hydraulic fracturing can release hazardous substances that are naturally occurring into the environment, such as arsenic, mercury, and naturally-occurring radioactive materials (NORMs).

All of these substances present risks to underground sources of drinking water and need to be regulated properly, especially because each well may be hydraulically fractured as many as 15 times. Hydraulic fracturing has been suspected in cases of drinking water contamination around the country, and in some areas where there has been hydraulic fracturing, residents have reported illnesses.

Does hydraulic fracturing really threaten drinking water?

In many places, hydraulic fracturing takes place on private property, even in backyards where children play or where a drinking water well is located.

Depending on local circumstances, property owners have little or no leverage in determining where hydraulic fracturing operations may take place.

Hydraulic fracturing frequently necessitates drilling through drinking water aquifers, exposing such aquifers to the risk of contamination from the tens of thousands of gallons of chemicals typically employed in a single fracturing operation or from naturally-occurring hazardous substances.

Is hydraulic fracturing regulated?

Hydraulic fracturing is one of only two underground injection processes exempted from the federal Safe Drinking Water Act.

States where hydraulic fracturing occurs have varying regulatory requirements, some of which are weak. For example, in most states oil and gas companies are not required to publicly disclose the types and amounts of chemicals that are injected underground in the fracturing process. In other words, nearby residents or landowners have no way of knowing what kinds of chemicals are being injected underground that may have contaminated their drinking water.

What is the FRAC Act?

The Fracturing Responsibility and Awareness of Chemicals Act (FRAC Act) was introduced in March 2011 in both the United States House (H.R. 1084) and Senate (S. 587). The bill has two purposes:

1. *To require companies to disclose the chemicals injected underground, and*
2. *To eliminate the exemption of hydraulic fracturing operations from regulation under the federal the Safe Drinking Water Act (SDWA).*

The FRAC Act also ensures that medical professionals can access information about the chemicals in hydraulic fracturing fluids if an individual has been harmed and needs medical care – which is not now the case.

Does the FRAC Act require new bureaucratic red tape?

No, the FRAC Act allows considerable flexibility. For example, the FRAC Act would allow states to administer the provisions of the Act. Importantly, states would be able to develop their own regulatory programs, tailoring them to their local conditions, with oversight from EPA. States with deficient regulations would need to strengthen them to meet EPA requirements.

What does the industry say about the bill?

The oil and gas industry claims that the FRAC Act is unnecessary and overly burdensome.
While the American Petroleum Institute claims that regulation will increase production costs by over $100,000 per well, its analysis was criticized by independent economic experts as ignoring important information, exaggerating costs, and being "untenable from an economic perspective." Under questioning from Representative Diana DeGette at a Congressional hearing, ExxonMobil CEO Rex

Tillerson could not state how much it would cost his company to comply with more protective regulations.

The industry claims that state regulations are sufficient, but state regulations vary widely and some, as pointed out above, are weak and generally do not provide for public disclosure. According to IHS Cambridge Energy Research Associates, federal regulation of hydraulic fracturing is unlikely to halt shale gas development.

Why does industry say that hydraulic fracturing does not contaminate drinking water?

In some cases, no one denies that groundwater has been contaminated—but the industry claims that the hydraulic fracturing process is not the cause. This has become a game of semantics.

Independent scientists and regulators have not had access to information about the chemicals used in the fluids and thus cannot adequately investigate cases of groundwater contamination, even where signs clearly point to hydraulic fracturing. Some cases where groundwater was contaminated during hydraulic fracturing operations have been attributed to faulty well structure and other oil and gas production causes instead of hydraulic fracturing per se, or have never been resolved.

Much better oversight and investigation is needed to fully determine the role of hydraulic fracturing in drinking water contamination incidents;; the FRAC Act will give the EPA the authority to oversee them.

Didn't EPA study this issue in 2004 and conclude there were no problems?

A 2004 EPA study of hydraulic fracturing in coalbed methane wells concluded that hydraulic fracturing "poses little or no threat" to drinking water and that no further study was necessary.

There have been many criticisms of this study as being insufficient and scientifically unsound—in fact, an EPA whistleblower noted that the conclusions were "unsupportable" and that some members of the study's review panel had conflicts of interest.

It is also critical to note that the study only considered coalbed methane wells, not shale gas plays or other locations where hydraulic fracturing takes place.

Should new regulation be put on hold while EPA completes the study urged by Congress?

Although Congress has directed EPA to investigate the impacts of hydraulic fracturing, we have enough information now to move forward to pass the FRAC Act.

Groundwater is being contaminated, the natural gas industry is moving to new areas with this technology, and many states have inadequate regulatory programs which do not even provide for public disclosure of the toxic chemicals used in this process.

Do supporters of this bill want to shut down oil or natural gas development?

No—natural gas is an important part of our energy economy, but its extraction must be "done right." This means that drinking water aquifers must be protected from contamination from the chemicals used in hydraulic fracturing operations, and that people living in communities where such operations take place have a right to know what chemical compounds are being used.

The FRAC Act ensures that wider production of natural gas throughout the U.S. will not impair the safety of drinking water.

5.0 Hydraulic Fracturing – Myths & Facts

Myth #1: Hydraulic fracturing fluids and products pose no real risk to our water supplies or public health.

Fact #1: Hydraulic fracturing fluids contain toxic chemicals and are being injected into and near drinking water supplies. According to the EPA, toxic chemicals in fracturing fluids include substances such as polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; sodium hydroxide; and diesel fuel, which contains benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals[1]. These chemicals have known negative health effects such as respiratory, neurological and reproductive impacts, impacts on the central nervous system, and cancer.

The Endocrine Disruption Exchange, Inc., (TEDX) has also recently documented health effects of chemicals used in 435 fracturing products. According to TEDX, the top four health effects for chemicals in these products include: skin, eye and sensory organ effects, respiratory effects, gastrointestinal effects, and brain and nervous system effects[2]. In addition to being injected into and near water resources, these chemicals are also being trucked through our communities and can spill and leak from trucks, pits, disposal wells, and flowlines. Aside from water contamination, communities are faced with public health threats from chemicals evaporating off drilling sites and residual chemicals that can spill or leak onto our soils.

Myth #2: There are no documented cases of fracturing fluids migrating into drinking water wells.

Fact #2: The oil and gas industry is splitting hairs with this claim. Complaints have been documented in Alabama, Colorado, New Mexico, Ohio, Texas, Virginia, West Virginia and Wyoming in which residents have reported changes in water quality or quantity following fracturing operations of gas wells near their homes. In mitigating and documenting these instances, industry and state regulators have cited casing failures, impacts from other mining operations, methane migration and other explanations for water contamination. Regulators and the public have had to accept these explanations, in part, because industry refuses to disclose the make-up of fracturing chemicals, and regulators do not know what specific chemicals they are looking for following fracturing complaints. The fact remains that landowners and communities are experiencing changes in water quality and quantity that occur during and after fracturing.

Myth #3: Our drinking water is not at risk from hydraulic fracturing because industry is fracturing at depths below the aquifers from which our communities are locating water wells.

Fact #3: There are number of ways in which hydraulic fracturing threatens our drinking water. Where drilling companies are developing fairly shallow oil or gas resources, such as some coalbed methane formations, drilling may take place directly in the aquifers from which we draw our drinking water. In that case, contamination may result from the fracturing fluids that are stranded underground, as the few studies that are available have shown that at least 20-30% of fracturing fluids may remain trapped underground.

Where drilling companies are developing deeper oil or gas resources, such as shale gas resources, there are a number of issues and concerns. Hydraulic fracturing can leave fluids stranded at these depths, and, through the high pressures used, can open up pathways for fluids or gases from other geologic layers to flow where they are not intended. This may impact deeper ground water resources that may be considered for drinking water supplies in the future. If fracturing wastewater disposal is conducted through underground injection wells, there is an additional risk for groundwater contamination. If wastewater disposal occurs in streams, the chemical make-up or temperature of the wastewater may affect aquatic organisms, and the sheer volume of water being disposed may damage sensitive aquatic ecosystems.

Additionally, fracturing fluid chemicals and wastewater can leak or spill from injection wells, flowlines, trucks, tanks, or pits. This contamination can be moved off-site through stormwater run-off. Finally, faulty casing, weak cementing, human error and geological unknowns can contribute to contamination from fracturing and other drilling practices.

Myth #4: All, or nearly all, hydraulic fracturing fluids are recovered during the fracturing process.

Fact #4: Factors affecting fracturing fluid recovery include flowback procedure, job design, specific reservoir conditions and other complexities. With multiple factors affecting fracturing fluid recovery, it is reasonable to assume that there will be a wide range in fluid recovery efficiencies. In fact, literature cited by EPA in their 2002 draft version of the hydraulic fracturing report confirmed this assumption. EPA cited or discussed four different studies[3]. These studies, conducted in non-coalbed methane basins, found that between 25% and 61% of certain hydraulic fracturing fluids flowed back to the well (that is, between 39% to 75 % was left stranded in some instances). One particularly compelling study showed that only 35-45% of the fracture fluids were recovered. This study was withdrawn from the EPA's final discussion of flowback and was not listed on their master reference list for the final report[4]. Citizens and groups working on this issue have often used the range of 20%-30% of fracturing fluids remaining in the ground without objection by industry. When considering the EPA's literature citations, this is a conservative estimate that generously grants a range of recovery efficiencies to the industry.

Myth #5: The practice of hydraulic fracturing and creating underground fractures is well-tested, controllable and safe.

Fact #5: It is critical for communities and decision makers to understand that hydraulic fracturing fluids not only contain toxic chemicals, but this operation utilizes high volumes of fluids and high pressures to intentionally open up underground pathways for gas or oil to flow. Injected fluids have been known to travel as far as 3,000 feet from a well, and fracturing fluids may remain trapped underground[5]. While industry claims that fracturing is a well-tested and controllable technology, computer models have shown that fractures can behave differently than predicted, and diagnostic techniques illustrating fracture history are rarely used. It is important for communities and decision makers to gather more information about fracture behavior, and to ensure that any stranded fluids do not remain in or move into our drinking water resources.

Myth #6: State regulations addressing casing and other aspects of drilling process such as spills and leaks adequately regulate fracturing products and practices.

Fact #6: Most states' policies regarding hydraulic fracturing amount to "don't ask and don't tell." At the state level, most oil and gas agencies do not require companies to report the volumes or names of chemicals being injected during hydraulic fracturing, and they have never conducted any sampling to determine the underground or surface fate of hydraulic fracturing chemicals. Without that information, neither states nor the public can begin to eliminate the use of toxic materials, nor adequately evaluate or develop monitoring programs to assess the risks posed by injecting these fluids underground.

Myth #7: Non-toxic and less toxic fracturing alternatives are in their infancy and not available for industry use.

Fact #7: Oil and gas operators are routinely using less toxic fracturing fluids in off-shore environments in order to meet federal requirements under the Clean Water Act, and some operators have tested and studied non-toxic fracturing fluids as they problem-solve site specific issues in the Black Warrior and San Juan Basins. Thus, the development of non-toxic or green fracturing fluids is not in its infancy.

The offshore oil and gas industry, for example, has had to develop fluids that are non-toxic to marine organisms in order to be allowed to discharge the fluids into the ocean. According to the Schlumberger web site: "Meeting stringent environmental guidelines in both the U.K. North Sea and the Gulf of Mexico (GOM), the new Schlumberger GreenSlurry system delivers consistent, earth-friendly performance. This slurry system, developed for use in all types of fracturing and gravel-packing operations in environmentally sensitive regions, features a unique carrier fluid. The new carrier fluid can be easily metered using all existing equipment.[6]" The public and decision makers must assume that Schlumberger and many other companies formulate these types of fluids because standard fracturing fluids are toxic to marine organisms and will not meet off-shore regulations. Because we don't have full disclosure of fracturing fluids, it remains vague as to how toxic or less toxic products designed for an offshore environment are to humans. However, industry studies and demonstrations have show that water without any additives is an effective fracturing fluid that is more economic in certain environments, and can solve production problems such as chemical gels (cross-linker gels) damaging coal permeability[7].

Myth #8: Lifting the exemption for hydraulic fracturing under the Safe Drinking Water Act would be unduly burdensome for States.

Fact #8: Congressional Representatives DeGette (CO), Salazar (CO) and Hinchey (NY) introduced a bill in 2008 that would reverse special treatment of Halliburton and other hydraulic fracturing companies by requiring regulation of hydraulic fracturing under the Safe Drinking Water Act (HR 7231). This effort establishes a minimum federal floor for protecting drinking water from hydraulic fracturing. According to the EPA, the regulation of underground injection does not require a new permitting process. A state could begin the specific regulation of hydraulic fracturing by issuing a general rule for hydraulic fracturing with safety standards. States already have permit processes for oil and gas wells and they could simply include hydraulic fracturing.

6.0 References – Sections 1, 2, & 3:

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2. In October of 2004, OGAP filed a Freedom of Information Act request with EPA to obtain the Material Safety Data Sheets (MSDS) supplied to the agency by hydraulic fracturing companies. (Freedom of Information Act, 5 U.S.C. 552, Request Number HQ-RIN-00044-05). The information in this table were contained in MSDS sheets from Schlumberger.
3. The Frac Focus web site does not allow users to link to lists of chemicals published for individual well sites. To view data on the Bakken Shale wells, go to FracFocus web site and Search: North Dakota. Dunn County. Marathon. Edward Darwin #14-35H. Fracture Date: 7/14/2011; and Search: North Dakota. Dunn County. ConocoPhillips. Intervale 31-35H well. Fracture Date: 8/9/2011.

7.0 References – Section 6

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6. (Schlumberger. Green Chemistry: Earth-friendly GreenSlurry system for uniform marine performance.) http://www.slb.com/content/services/stimulation/execution/greenslurry.asp
7. See L. Sumi's discussion in Our Drinking Water at Risk (2005). Two relevent industry studies on non-toxic fracturing fluids include: (i) T.L. Logan. 1994. "Preliminary results of cooperative research efforts with Phillips Petroleum Company and Amax Oil and Gas Inc., San Juan Basin." Quarterly Review of Methane from Coal Seams Technology. April 1994 11(3&4):39-49. (ii) Puri, R., King, G.E., Palmer, I.D. Amoco Production Co. 1991. 'Damage to Coal Permeability During Hydraulic Fracturing.' Paper presented at the Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium, Denver, CO, April 15-17, 1991.

The Oil and Gas Industry's Exclusions and Exemptions to Major Environmental Statutes

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The Oil and Gas Industry's Exclusions and Exemptions to Major Environmental Statutes

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Executive Summary

The oil and gas industry enjoys sweeping exemptions from provisions in the major federal environmental statutes intended to protect human health and the environment. These statutes include the:

- **Comprehensive Environmental Response, Compensation, and Liability Act**
- **Resource Conservation and Recovery Act**
- **Safe Drinking Water Act**
- **Clean Water Act**
- **Clean Air Act**
- **National Environmental Policy Act**
- **Toxic Release Inventory under the Emergency Planning and Community Right-to-Know Act**

This lack of regulatory oversight can be traced to many illnesses and even deaths for people and wildlife across the country. There are a variety of chemicals used during the many phases of oil and gas development. These chemicals also produce varying types of waste throughout these processes. Because of the exemptions and exclusions, toxic chemicals and hazardous wastes are permeating the soil, water sources and the air threatening human health to an alarming extent. In order to adequately remedy the negative impacts on human health and the environment, the following recommendations must be addressed:

1) Crude oil and petroleum must be covered under the *Comprehensive Environmental Response, Compensation, and Liability Act* in order to protect human health and the environment from spills and leaks of hazardous and carcinogenic materials on well sites. This is the only way to currently assist overburdened federal and state programs in light of the exponential growth of oil and gas development in the United States.
2) To protect human health and the environment, oil field wastes must be regulated under the *Resource Conservation and Recovery Act* in order to ensure the proper handling and disposal of hazardous and carcinogenic wastes generated by oil and gas development. Otherwise, the petroleum industry will continue to dispose of oil field waste in ways that can pollute soil, surface and groundwater.
3) Hydraulic fracturing must be regulated by the Environmental Protection Agency under the *Safe Drinking Water Act* in order to adequately protect the United State's drinking water supply from the harmful chemicals used during this process. This recommendation includes a total ban on the use of diesel fuel as one of the additives in the hydraulic fracturing process.
4) Stormwater discharges from all oil and gas development must be regulated under the *Clean Water Act* by the federal government in

order to provide the states with a proper foundation from which to build adequate stormwater programs that will protect human health and the environment from expanding oil and gas development.

Emissions from all oil and gas facilities must be aggregated under the *Clean Air Act* in order to ascertain the true hazardous effect on air quality. Also, hydrogen sulfide must be re-established as a hazardous air emission under the Clean Air Act in light of the current available data regarding its negative impacts on human health and the environment.

Because of the disruptive nature of oil and gas activities on human health and the environment, none of these activities ought to qualify for the categorical exclusion under the *National Environmental Policy Act.* All oil and gas activities must be assessed for impacts on the environment under the more comprehensive environmental assessment and environment impact statement in order to properly fulfill the intentions of the statute.

The petroleum industry must be made to disclose the chemicals used during the development stages under the *Toxic Release Inventory within the Emergency Planning and Community Right-to-Know Act,* in order to ensure that human health and the environment can be protected from these often-hazardous and carcinogenic substances.

One of the goals for the Oil and Gas Accountability Project is to help communities and citizens better understand and protect themselves from the health and environmental impacts associated with toxic oil and gas chemicals and wastes. The following report explains these exemptions, how they apply to oil and gas development, and the consequences to human health and the environment that are left behind. To learn more about the devastating impacts of oil and gas development, read *Oil and Gas at Your Door? A Landowner's Guide to Oil and Gas Development* and *Our Drinking Water At Risk: What EPA and the Oil And Gas Industry Don't Want Us to Know About Hydraulic Fracturing*, available at: www.ogap.org.

Comprehensive Environmental Response, Compensation, and Liability Act – CERCLA

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980 regulates the clean up of hazardous substance releases into any part of the environment, including air, water, and land. It further requires the reporting of hazardous substance releases, as well as the location of hazardous storage, treatment, and disposal sites. The statute also establishes the Superfund, a trust fund to pay for hazardous waste clean up, derived from taxes imposed on oil and chemicals, as well as fines and penalties levied by the Environmental Protection Agency (EPA).[1] Today, the fund falls short of project goals annually because over the past 10 years Congress has abolished these taxes and draws on the general tax revenue to fund this program.[2]

CERCLA seeks to establish a comprehensive governmental response to actual or threatened hazardous substance releases. The law is predominantly concerned with orphaned facilities-where ownership is undetermined and the site is closed or no longer operating as it once was-and sites owned or operated by persons who do not have the financial resources or who are unwilling to undertake appropriate response action. The statute also provides a federal cause of action to recover the costs incurred for responses to releases. This cause of action was intended for the federal government response program, but extends to any potentially responsible party (PRP). Under the legal doctrine of joint and several liability, PRPs are able to seek restitution from each other should any of them pay all or part of the clean costs. PRPs are broken into four distinct classes: (1) current owners and operators; (2) owners and operators at the time of disposal; (3) generators of the substances; and (4) transporters of the substances.[3]

CERCLA is essentially a measure through which Congress intended to gain access to the financial resources of any company that qualifies as a PRP, regardless of the PRP's degree of responsibility for the release. The Superfund Amendments and Reauthorization Act (SARA) of 1986 gave the EPA more control over settlement options with PRPs, established a strict time frame for initiating a clean up response, required assessment of the threats that individual sites pose to human health, and increased state and public participation in the decision-making process.

Generally speaking, there are four requirements necessary to establish liability under CERCLA: (1) A determination must be made that the site involved is a "facility" under the definition of the statute; (2) a "release" or "threatened release" as defined by the statute of a "hazardous substance" must have occurred at the site; (3) the government or a private party must

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[1] 42 U.S.C. § 9631, repealed by Superfund Amendments and Reauthorization Act of 1986, Pub. L. 99-499, 100 Stat. 1613, 1772 (codified at I.R.C. § 9507 (1988)).
[2] http://www.cpeo.org/lists/brownfields/2004/msg00112.html.
[3] 42 U.S.C. § 9607(a)-(c).

have incurred response costs as a result of the release; and (4) there is a determination that the defendant is a PRP. [4] Section 101(14) of CERCLA lists the hazardous substances that are covered under the statute. Included in the list are benzene, toluene, xylene, and ethylbenzene, each of which is an element of petroleum; inexplicably, however, the last clause of this section excludes crude oil and petroleum.[5] Thus, hazardous chemicals that would otherwise fall under the ambit of CERCLA are immune from the statute when encompassed in petroleum or crude oil.

The negative impacts on human health and the environment resulting from this petroleum exclusion are being experienced now and could become overwhelming. Petroleum facilities that would otherwise fall under CERCLA and require PRPs to cleanup are excluded. These toxic waste dumps are left for other federal and state programs to remediate and reclaim, or simply abandoned to pollute the environment and threaten public health. These cleanup projects are often too numerous and expensive for authorities in these programs to champion.

The number of improperly abandoned and remediated well sites already overwhelms the federal agency responsible for oil and gas leasing on federal land, the Bureau of Land Management (BLM), and many states that are saturated with oil and gas development.[6] A 2005 report by the Federal General Office of Accountability found many field office's funding and staffing to be so inadequate that most of the environmental responsibilities (e.g., inspections for proper plugging and abandoning, remediation) fell to the wayside.[7] The Blancett family, as well as many other ranchers in the western United States can attest to the failure by state and federal remediation programs to properly address leaks, spills, and debris left at well sites on their property. Often, their land or land adjacent to theirs is strewn with petroleum waste products and debris just left by irresponsible petroleum companies. The waste products leak into soils and nearby streams poisoning livestock and wildlife.[8]

In light of the exponential growth of oil and gas development in the western United States, this is a real threat to the health and welfare of the public and the environment. CERCLA and its intended benefits are not available to the communities faced with a real or potential petroleum or crude oil release. Because of this exclusion, citizens will have to relocate and pay for medical treatment on their own while thousands of gallons of petroleum or crude oil

[4] 42 U.S.C. § 9601(9) and (22).
[5] 42 U.S.C. § 9601(14).
[6] Western Organization of Resource Councils, Filling the Gaps: How to Improve Oil and Gas Reclamation and Reduce Taxpayer Liability (August 2005).
[7] United States Government Accountability Office, Report to the Ranking Minority Member, Committee on Homeland Security and Governmental Affairs, U.S. Senate, OIL AND GAS DEVELOPMENT: Increased Permitting Activity Has Lessened BLM's Ability to Meet Its Environmental Protection Responsibilities (June 2005).
[8] Oil and Gas Accountability Project, Oil and Gas at Your Door? A Landowner's Guide to Oil and Gas Development, p. IV-19 (2005). Available at: http://www.earthworksaction.org/publications.cfm?pubiD=91.

permeate the earth and water sources in anticipation of a court decision to determine liability.

The time has come to repeal the petroleum exclusion. The federal government must react to these situations so as to protect its citizens from the hazardous and carcinogenic poisons inherent in petroleum and crude oil.

Resource Conservation and Recovery Act – RCRA

The Resource Conservation and Recovery Act (RCRA) of 1976 is currently divided into 10 subchapters: I through X, comprising four interrelated programs for the management of hazardous waste and solid waste found at Subchapters III, IV, IX, and X. Subchapter III, commonly referred to as Subtitle C, creates a federal "cradle-to-grave" hazardous waste management program. Subchapter IV, commonly referred to as Subtitle D, encourages states to develop comprehensive plans to manage primarily nonhazardous solid wastes (e.g., household waste). Subchapter IX, commonly referred to as Subtitle I, regulates the use and monitoring of underground storage tanks. Subchapter X, commonly referred to as Subtitle J, establishes regulations for medical waste from the time it is generated until the time it is disposed.

Congress defined hazardous waste in RCRA § 1004(5), but left the EPA to decide through a Regulatory Determination the specific characteristics of hazardous waste and to promulgate lists of wastes meeting those characteristics.[9] The definition of a hazardous waste under RCRA § 1004(5) is as follows:

[A] solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical, or infectious characteristics may-

A. cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
B. pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.[10]

In 1978, the EPA issued proposed hazardous waste guidelines and regulations as requested by Congress. At this time, the agency was poised to consider oil field wastes as "special wastes" under Subtitle C. However, Congress responded to these proposed regulations with the Solid Waste Disposal Act (SWDA) in 1980, which exempted oil field wastes from Subtitle C entirely until the EPA could prove these wastes were a danger to human health and the environment. In 1988, the EPA's Regulatory Determination ultimately agreed with Congress' decision to exempt oil field wastes due to the "adequate" state and federal regulations already in place and the costs

[9] A Regulatory Determination is an agency decision founded on authority granted by Congress to determine specific details of legislation based on its expertise in the field.
[10] 42 U.S.C. § 6903-6992.

and economic impacts to the petroleum industry should it be regulated under Subtitle C.[11]

Despite the considerable regulatory changes by EPA regarding the regulation of oil field waste in determining that it was not hazardous enough to be regulated under Subtitle C, the 1988 Regulatory Determination provides a comprehensive list of wastes excluded from and included within the scope of the oil field waste exemption. A helpful article from the Director and Senior Staff Attorney at the Railroad Commission of Texas summarizes these lists. Oil field wastes typically fall into the following categories:

1) Produced waters-mineralized waters produced with and then separated from oil and gas.
2) Drilling fluids-mixtures of water, clay, barite, and other additives used in drilling wells.
3) Associated wastes-other wastes uniquely associated with drilling and production operations, such as crude oil tank bottoms (e.g., oil, sediment, and water).[12]

In addition, the Regulatory Determination clarifies the meaning of RCRA § 3001(b)(2)(A)'s exemption for "other wastes associated with the exploration, development or production of crude oil or natural gas" by stating that such "other wastes" include "rigwash, drill cuttings, and wastes created by agents used in facilitating the extraction, development, and production of the resource, and wastes produced by removing contaminants prior to the transportation or refining of the resource."[13]

Further clarification by the EPA in 1993 provides a rule of thumb for determining if certain oil field wastes fall within the RCRA exemption. It states, "Since 1987, the terms uniquely associated and intrinsic have been used as interchangeable synonyms in various documents in reference to oil and gas wastes qualifying for the exemption from Subtitle C regulation…A simple rule of thumb for determining the scope of the exemption is whether the waste in question has come from down-hole (i.e., brought to the surface during oil and gas E & P operations), or has otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product (e.g., waste emulsifiers, spent iron sponge). If the answer to either question is yes, the waste is most likely considered exempt."[14]

In many cases, these "other" wastes contain known carcinogens such as benzene, toluene, and xylene. The effect of the RCRA exemption is to allow these deadly chemicals that are otherwise considered hazardous within the

[11] 53 Fed.Reg. 25, 447.
[12] Terri Eaton and Lori Wrotenbery, Environmental Services for the Oil and Gas Division of the Railroad Commission of Texas, *State Environmental Regulation in the Oil Field* (October 1994).
[13] 53 Fed.Reg. 25, 454.
[14] 58 Fed.Reg. 25, 448.

same statute to permeate the earth and water sources poisoning the public and the environment. For example, waterfowl, wildlife, and livestock may be attracted to open pits and tanks used to store and/or dispose of oil, produced water, or separate oil from produced water. The risks posed to wildlife have been documented in numerous studies. In Wyoming, the U.S. Fish and Wildlife Service has found deer, pronghorn, waterfowl, songbirds, and rabbits in these open pits and tanks. Even if the animals are not killed in these areas, the oil and chemicals can have debilitating health effects.[15] Despite a few state regulations pertaining to oil and gas field wastes, it is typical for the oil and gas industry to dispose of these wastes in earthen pits and on-site burial.[16] The potential for migration of contaminants in the soil and water sources in these areas is at the very least concerning to those who live in the oil and gas patches.

Relying on 1985 data, the EPA estimated that 70,000 oil and gas wells and 800,000 active production sites generated 361 million barrels of drilling waste, 20.9 billion barrels of produced waters, and 11 million barrels of associated wastes, such as workover fluids and tank bottoms.[17] Considering the exponential growth of the oil and gas industry over the past 20 years, it is time regulators focus on the adequacy of existing regulations to protect human health and the environment from the real and potential dangers of the oil and gas industry's waste.

The Safe Drinking Water Act – SDWA

The Safe Drinking Water Act (SDWA) of 1974 was established to protect the quality of drinking water in the United States. This law focuses on all waters actually or potentially designed for drinking use, whether from above ground or underground sources. The SDWA was amended through the comprehensive Energy Policy Act in 2005.

The 2005 amendment managed to effectively dilute the protections provided to the public by the SDWA in three ways. First, hydraulic fracturing (fracking) operations were completely exempted from regulation under the SDWA. Second, the Energy Policy Act asked for the voluntary discontinuance of diesel fuel use in fracking operations in lieu of seizing the opportunity to ban diesel fuel use altogether. Lastly, underground injection in oil and gas operations was defined so as to alleviate the EPA from regulating threats to drinking water from fracking fluids unless diesel fuel additives are used; this remains a discretionary regulation of diesel fuel additives on the part of the EPA.[18] The last prong of the exemption simply provides more legislative support for EPA's decision to not regulate fracking operations even if diesel fuels are being injected into underground drinking water sources.

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[15]A list of studies can be found in: Pedro Ramirez Jr., U.S. Fish and Wildlife Service, "Wildlife Mortality Risk in Oil Field Waste Pits," *Contaminants Information Bulletin* (December 2000).
[16] New Mexico Energy, Minerals and Natural Resources Department, *New Mexico Follow-up and Supplemental Review – State Review of Oil and Natural Gas Environmental Regulations*, p. 6 (2001).
[17] 53 Fed.Reg. 25, 448.
[18] http://energycommerce.house.gov/legviews/108lvhr0006-oilgas.shtml.

Fracking is a technique used to stimulate oil and gas production from conventional oil and gas wells, as well as nonconventional oil and natural gas sources (e.g., coalbed methane, tight sands). Typically, it involves high-pressure injection of water, sand, and chemicals into underground geological formations, which causes the formations to fracture. The fracturing then allows the various petroleum products to flow more easily to production wells.

Fracking fluids typically contain a host of chemicals used to optimize the fracturing process. These additives include gels, polymers, biocides, fluid loss agents, thickeners, enzyme breakers, acid breakers, oxidizing breakers, friction reducers, and surfactants. Some of these chemicals are toxic simply in their pure form exclusive of their effect when combined and injected into groundwater-bearing formations.[19]

EPA has determined that in some cases, fracking chemicals are injected directly into underground sources of drinking water (USDW) during the course of normal coalbed methane (CBM) fracturing operations.20 While not all coal formations are USDWs, the EPA has stated that 10 out of 11 CBM basins in the U.S. are located at least in part within USDWs. The co-location of coalbeds and USDWs is known to occur in Alabama, Arkansas, Colorado, Kansas, Montana, New Mexico, Virginia, Washington, West Virginia, and Wyoming. There are possible co-locations in Nebraska, Pennsylvania, and Kentucky.[21]

The above information was generated by the EPA in a report the agency released in 2004 on the environmental risks posed by the fracking of coalbeds. This study was intended to assess the potential for fractured coalbeds to contaminate USDWs. Phase I of this study was launched in 2000; the findings of this phase would determine if further studies were necessary. [22]

The EPA released its final version of the Phase I study in 2004 entitled, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. The main finding of this study stated, "the injection of hydraulic fracturing into CBM wells poses little or no threat to Underground Sources of Drinking Water."[23] The Energy Policy Act of 2005 codified this finding and provided the legislative vehicle to deregulate hydraulic fracturing except when diesel fuels are used and even then regulation by the EPA would be discretionary.

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[19] U.S. Environmental Protection Agency, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA Document# 816-R-04-003, pp. 4-5 (June 2004).
[20] Id. at p. ES-1.
[21] Id. at Chapter 5.
[22] Id. at p. 2-1.
[23] Id. at p. ES-16.

Unfortunately, the EPA's findings are not consistent with the numerous personal accounts of those living in oil and gas patches around the country. Peggy Hocutt and her husband retired to their house on the river in Jefferson County, Alabama. After years of mysterious ailments affecting everyone in the area and tap water that smelled of petroleum, Mrs. Hocutt had black, jellied grease coming out of her faucets. She and many of her neighbors also had cancer. The energy company hydraulically fracturing in that area and the state of Alabama refused to admit that their aquifer had been contaminated by fracking activities. Instead, the company refused to renew their land lease and evicted them from the property. They lost their physical and mental wellbeing, as well as a forty-year investment in their retirement home.[24]

The EPA has been highly criticized by internal staff, federal legislators, and respected peers on the 2004 study. Each of these critics has challenged the EPA's conclusions while insisting that additional studies be conducted under a non-bias peer review panel.[25] These are the necessary steps to take in order to determine the information critical to assessing Congressional and EPA compliance with the mandates under the SDWA to protect the United States' drinking water sources.

Clean Water Act – CWA

Growing public awareness and concern for controlling water pollution led to the enactment of the Federal Water Pollution Control Act Amendments of 1972. As amended in 1977, this law became commonly known as the Clean Water Act (CWA). The CWA established the basic structure for regulating discharges of pollutants into the waters of the United States. It gave EPA the authority to implement pollution control programs such as setting wastewater standards for industry. The CWA also continued requirements to set water quality standards for all contaminants in surface waters. It also made it unlawful for any person to discharge any pollutant from a point source into navigable waters, unless a permit was obtained under its provisions.[26]

From 1987 until 2005, the oil, gas, and mining operations exemption provided that no CWA permit was required for stormwater runoff at oil and gas exploration, production, processing and treatment operations, and transmission facilities where the runoff consisted entirely of flows from conveyances such as pipes and ditches for rainwater collection, provided that the runoff was not contaminated by contact with raw materials or wastes. [27] However, the EPA decided in two prior phases of stormwater permitting, 1990 and 1999, to assert its authority to regulate certain stormwater

[24] Oil and Gas Accountability Project, *Oil and Gas at Your Door? A Landowner's Guide to Oil and Gas Development,* p. IV-4 (2005). Available at: http://www.earthworksaction.org/publications.cfm?pubiD=91.
[25] Oil and Gas Accountability Project, Our Drinking Water At Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know About Hydraulic Fracturing, p. 2 (2005). Available at: http://www.earthworksaction.org.
[26] www.epa.gov.
[27] 33 U.S.C. § 1342(1)(2).

discharges from oil and gas construction sites based on the belief that sediment from the construction site constitutes a pollutant. This action was justified because of the effects of large amounts of sediment being discharged into surface waters over a short period of time. The 1990 rule regulated activities disturbing five or more acres of land.[28] The 1999 rule added the regulation of activities disturbing one to five acres of land.[29]

Despite the EPA's efforts over the past 15 years to maintain these stormwater regulations, the 2005 Energy Policy Act amended the CWA to provide that sediment is no longer considered a pollutant. The broadened exemption provided in the 2005 Energy Policy Act applies to all oil and gas field construction activities and operations, including those necessary to prepare a site for drilling and for the movement and placement of drilling equipment. The EPA has confirmed this interpretation by stating, "all covered oil and gas-related construction activities are eligible for the NPDES permitting exemption for their uncontaminated stormwater discharges without regard to the amount of acreage disturbed."[30]

The EPA further clarified the broad application of the exemption to construction sites as "[f]ield activities or operations" include "the construction of drilling sites, drilling waste management pits, access roads, in-field treatment plants and the transportation infrastructure (e.g., crude oil and natural gas pipelines, natural gas treatment plants and both natural gas pipeline compressor and crude oil pump stations) necessary for the operation of most producing oil and gas fields."[31] "Processing" includes both oil and gas field activities and involves removal of contaminants such as salt water, sediment, pipe scale, rust and organic material, most commonly in a separator. "Transmission" includes all necessary infrastructure to deliver natural gas or crude oil from the producing fields to the final distribution center (for natural gas) or refinery (for crude oil).[32]

The 2005 Energy Policy Act and the subsequent EPA concession to exempt sediment from regulation under the CWA for oil and gas construction activities is inconsistent with past agency decisions because the exact same sediment from construction sites has required a stormwater discharge permit for the past 15 years at the insistence of the EPA. Has the sediment from oil and gas construction sites changed dramatically in the past few years such that it can no longer be considered a pollutant? Furthermore, the CWA requires other industries to obtain a stormwater permit on the basis that its sediment is considered a pollutant. [33] Does the oil and gas industry deserve preferential treatment over other industries in the United States?

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[28] 55 Fed.Reg. 47990 (November 16, 1990).
[29] 64 Fed.Reg. 68721 (December 8, 1999).
[30] 71 Fed.Reg. at 33631-33632.
[31] 71 Fed.Reg. at 33635-33636.
[32] 71 Fed Reg. at 33635-33636.
[33] 33 U.S.C. § 1342(p)(3)(A).

Landowners in the oil and gas patch would certainly disagree with the EPA's finding that sediment from petroleum sites and stormwater from oil and gas fields do not qualify as pollutants. Ed Swartz owns a ranch in Campbell County, Wyoming. He believes the best feature of his property to be Wildcat Creek, which meanders about eight miles through his ranch irrigating an important grazing field. Stormwater and produced water from his neighbor's gas pad flooded his creek and destroyed his grazing and hay fields. This is an expense that was left for him to bear because of the CWA exemption for oil and gas activities.[34]

It is important to note that despite the federal government's refusal to regulate stormwater discharges by the oil and gas industry, individual states and tribes may regulate stormwater associated with these activities under their own independent authority.[35] Colorado Department of Public Health and the Environment (CDPHE) serves as a progressive example in this area. It has maintained the stormwater permit requirement for oil and gas construction sites that was removed by the 2005 Energy Policy Act.[36]

However, this problem is often too large for a state program to monitor on its own. In May of 2007, the Colorado Oil and Gas Conservation Commission cited one exploration company nine times for wells that had insufficient stormwater runoff protections. Because of the insufficient drainage, each of the nine well sites had flooded from snowmelt and oil was visible in various areas around each wellpad. In one case, the oil-laden snowmelt was discharging into a nearby creek.[37] In light of the exponential growth of oil and gas exploration and production, the federal government ought to assist the states by adopting minimum regulations to provide a floor upon which states can build adequate stormwater regulatory programs for the petroleum industry to protect our precious surface water resources.

The Clean Air Act – CAA

The Clean Air Act (CAA) is the comprehensive federal law that regulates air emissions from area, stationary, and mobile sources. This law authorizes the EPA to establish National Ambient Air Quality Standards (NAAQS) to protect public health and the environment. The goal of the CAA was to set and achieve NAAQS in every state by 1975. The setting of maximum pollutant standards was coupled with directing the states to develop state implementation plans (SIP's) applicable to appropriate industrial sources in that state.

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[34] Oil and Gas Accountability Project, *Oil and Gas at Your Door? A Landowner's Guide to Oil and Gas Development,* p. IV-4 (2005). Available at: http://www.earthworksaction.org/publications.cfm?pubiD=91.
[35] EPA states "[t]his final rule is not intended to interfere with the ability of States, Tribes, or local governments to regulate any discharges through a non-NPDES permit program." 71 Fed.Reg. at 33635.
[36] Colorado Department of Public Health and the Environment, Water Quality Control Division, Stormwater program, *Stormwater Factsheet-Construction at Oil and Gas Facilities*, pg. 1 (July 2007).
[37] Rocky Mountain News, *Driller Leaves Mess Behind: Nervous Neighbors Seek Answers from Oil, Gas Commission* (July 19, 2007).

The CAA was amended in 1977 primarily to set new goals, specifically dates, for achieving attainment of NAAQS since many areas of the country had failed to meet the deadlines. The 1990 amendments to the CAA in large part were intended to meet unaddressed or insufficiently addressed problems such as acid rain, ground-level ozone, stratospheric ozone depletion, and air toxics.[38]

The CAA program to control major sources of pollutants has established limits called the National Emission Standards for Hazardous Air Pollutants (NEHAPS). The standards must be met by installing the Maximum Achievable Control Technology (MACT) for each source. [39] Smaller sources of pollutants that are under common control and are located in close proximity to perform similar functions are considered as one source of emissions. This aggregation is intended to regulate smaller sources that may actually be as harmful as larger sources due to the concentration of emissions.

The CAA provides that oil and gas wells, and in some instances pipeline compressors and pump stations, shall not be aggregated together to determine if they are subject to the provisions that establish NEHAPS and thus require MACT. This exemption to the aggregation requirement allows the oil and gas industry to pollute the air while being largely unregulated under the CAA. Despite efforts by individual states and tribes to implement their own regulations, these generally fall short of addressing the air pollution problems across the country because the oil and gas industry is growing exponentially and rapidly expanding into new areas.

In Colorado alone, oil and gas exploration and production emits on average approximately 70,000 tons of volatile organic compounds (VOCs) and 30,000 tons of nitrogen oxide per year.[40] VOCs produce smog when combined with nitrogen oxides, sunlight, and heat.[41] Oil and gas operations also release approximately 20,000 tons of carbon monoxide per year, which is more than twice the amount released by all coal and natural gas fired power plants in Colorado.[42]

Fortunately, Colorado recently implemented regulations to reduce VOCs from oil and gas operations in the state and increased reporting requirements.[43] Despite these regulatory improvements, the fact remains that record numbers of drilling permits have been issued in several western states this past year and oil and gas wells are totally exempt from federal air quality

[38] www.epa.gov.
[39] 42 U.S.C. § 7412(n)(4).
[40] Rocky Mountain Clean Air Action Power Point Presentation on Air Pollution from Oil and Gas Development and Proposed Colorado Smog Reductions (2007). Available at: http://www.ourcleanair.org/Resources.html.
[41] Oil and Gas Accountability Project, *Oil and Gas at Your Door? A Landowner's Guide to Oil and Gas Development,* p. I-53 (2005). Available at: http://www.earthworksaction.org/publications.cfm?pubiD=91.
42 Rocky Mountain Clean Air Action Power Point Presentation on Air Pollution from Oil and Gas Development and Proposed Colorado Smog Reductions (2007). Available at: http://www.ourcleanair.org/Resources.html.
[43] http://www.cdphe.state.co.us/ap/oilgas.html.

regulations. While regulations by individual states and tribes are a step in the right direction, the federal government needs to set floor standards from which all states with oil and gas development can build upon to improve national air quality.

Hydrogen sulfide leaks are another serious air quality concern resulting from oil and gas development. In 1997, Carol Browner, former Administrator of the EPA admitted in no uncertain terms that hydrogen sulfide was eliminated from the Clean Air Act list of extremely hazardous substances by powerful oil and gas lobbying.[44] This elimination occurred in spite of the EPA study, *Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas*, which documented a large number of oil and gas related accidents occurring in North America and concluded that accidental releases of hydrogen sulfide pose a great risk to public health.[45]

Accidental and intentional releases of hydrogen sulfide may occur at sour gas well operations. Sulfur dioxide and trioxide form when hydrogen sulfide is burned at these facilities, which further contributes to air pollution and health problems. Furthermore, because hydrogen sulfide is heavier than air it often settles in low-lying areas where it can accumulate in concentrations that can injure or kill livestock, wildlife, and human beings.[46]

Common symptoms affecting those exposed to chronic, periodic, or puff releases of low levels of hydrogen sulfide include: headache, skin complications, respiratory and mucus membrane irritation, respiratory soft tissue damage and degeneration, confusion, impairment of verbal recall, memory loss and prolonged reaction time.[47]

Dr. Kaye Kilburn, considered by some to be the world's foremost authority on hydrogen sulfide poisoning, recently discussed one compelling incident in California.[48] "Some of you will remember the 1992 earthquake at Long Beach and Wilmington. That turned out not to be an earthquake at all, but it was an explosion of the desulphurization plant at Texaco down north of Pacific Coast Highway. Twenty thousand people, at least, were exposed to hydrogen sulfide. What does it do to children? Well, from two schools, special education teachers came to me for their own problems, and then said, 'I have students who were passing and can't pass anymore. I have had more referrals for special education since that explosion than I ever remember having, and I have seen many children drop out of school because they're uneducable.' If this is what we want as a Belmont High School, we

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[44] Carol Browner's comments were stated during her presentation at the November 1997 National Public Health Convention in Indianapolis, Indiana, and aired nationally during the documentary "Town Under Siege," narrated by Ed Bradley, December 23, 1997.
[45] *Survey of Accidental and Intentional Hydrogen Sulfide Releases Causing Evacuations and/or Injuries in Manistee and Mason Counties from 1980 to 2001*, pg. 3.
[46] La Plata County (Colorado), *La Plata County Impact Report*, pg 3-105 (2002).
[47] Kilburn, Kaye, "Hydrogen Sulfide and Reduced-sulfur Gases Adversely Affect Neurophysiological Functions," *Toxicology and Industrial Health*. Vol. 11, No. 2. pp. 192-193 (1995).
[48] http://www.fulldisclosure.net/Transcripts/2005/02/transcript-from-dutton-interview-20905.html.

already have seen at Wilmington School how this plays out. I don't really think it can be justified to do the experiment again. It was conclusive the first time."

In light of the information available on the amounts of toxins the oil and gas industry is emitting into the air and the known health impacts on the public and the environment, the federal government has a duty to reconsider the applicable CAA exemptions. Furthermore, the elimination of hydrogen sulfide as an extremely hazardous substance from the Act is completely unacceptable considering the information available regarding the negative impacts on human health and the environment.

National Environmental Policy Act – NEPA

The National Environmental Policy Act (NEPA) was one of the first laws ever written that establishes the broad national framework for protecting our environment.[49] NEPA's basic policy is to assure that all branches of government give proper consideration to the environment prior to undertaking any major federal action that significantly affects the environment.

In order for the proper consideration requirement to be met, federal agencies must take a hard look and disclose any possible and real impacts on the environment resulting from the proposed action and the offered alternatives. In most instances this also requires the opportunity for public comment on this action and the alternatives. NEPA requires that federal agencies first conduct an environmental assessment (EA) to determine if there will be significant impacts on the environment from the proposed action. If the agency finds there will be a significant impact, it is then required to conduct the more stringent environmental impact statement (EIS) in order to meet the proper consideration and opportunity for public comment requirements. Each of these documents, in different levels of detail, lay out the specifics of the proposed action, the alternatives, and the associated impacts on the environment.

The Energy Policy Act of 2005 created a "rebuttable presumption" that several oil and gas related activities ought to be analyzed and processed by the Interior and Agricultural Departments under a less stringent process known as a "categorical exclusion" (CE). The CE is considerably less comprehensive than the traditional environmental assessment (EA) or the environmental impact statement (EIS) and does not allow for any public comment. The activities eligible for the CE include:

1) Individual surface disturbances of less than five acres so long as the total surface disturbance on the lease is not greater than 150 acres

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[49] 42 U.S.C. § 4321 et seq. (1969).

and site-specific analysis in a document prepared pursuant to NEPA has been previously completed.

2) Drilling an oil or gas well at a location where drilling occurred previously within five years prior to the date of spudding the well.
3) Drilling a well within a developed field for which an approved land use plan or any environmental document prepared pursuant to NEPA analyzed such drilling as a reasonably foreseeable activity, so long as such plan or document was approved within five years prior to the date of spudding the well.
4) Placement of a pipeline in an approved right-of-way corridor, so long as the corridor was approved within five years prior to the date of placement of the pipeline.
5) Maintenance of a minor activity, other than any construction or major renovation or a building or facility.[50]

Under the "rebuttable presumption," section 390 effectively shifts the burden from the agency to the public to prove that an activity requires further analysis. Prior to 2005, the agency had the burden of showing that no harm will occur from the type of activity at issue. Now, the public has the burden of proving that the above activities occur in an area with "extraordinary circumstances" and require a full NEPA review. "Extraordinary circumstances" are those in which a normally excluded action may have a significant environmental effect, thus requiring additional analysis and action.[51]

Section 390 has significantly hampered the opportunity for public involvement in major oil and gas activities in contravention to the original intentions of NEPA by allowing federal agencies to permit oil and gas operations more easily without having to consider or address the concerns of nearby landowners. The ultimate effect of this exclusion is to give the oil and gas industry a blanket permit to threaten public health and the environment in the name of administrative efficiency. This is just one more tool used by the oil and gas industry to streamline their piracy and contamination of the American public.

The Toxic Release Inventory of EPCRA

The Toxic Release Inventory (TRI) was created by section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) in 1986. It contains detailed toxic chemical release reports submitted by manufacturing, mining, electric utility, RCRA subtitle C, solvent recovery, chemical distributor, and petroleum bulk facilities to the EPA. The information is generated and disseminated to the public for their protection.[52]

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[50] The Energy Policy Act of 2005, Section 390.
[51] *Id.*
[52] EPA Guidance Document: The Emergency Planning and Community Right-to-Know Act-Section 313 Release and Other Waste Management Reporting Requirements (2001).

The information on chemical use and release includes: point and fugitive on-site air releases, water releases, on and off-site land releases, underground injection, transfers to a Publicly Owned Treatment Works (POTW) or waste management facility, including the name and address of the facility, and specific on-site waste treatment and management practices.[53]

Those who must report their releases include any facility that has 10 or more full-time employees, is in a listed SIC code, and processes or manufactures more than 25,000 lbs of a listed chemical or otherwise uses more than 10,000 lbs; or processes, manufactures, or otherwise uses more than 1/10 gram, 10lbs, or 100lbs of a listed Persistent, Bioaccumulative and Toxic (PBT) chemical (e.g., brominated flame retardants).[54]

The exploration and production of oil and natural gas meet the criteria for those who must report. Generally, they have 10 or more full-time employees involved in the construction and operation of each individual drilling site, their listed SIC code is 13, and they "otherwise use" more than 10,000 lbs of a listed chemical (e.g., benzene, toluene and xylene). Furthermore, the oil and gas industry releases include point and fugitive on-site air, land and water sources. However, EPA has chosen to abdicate its responsibility under the EPCRA to inform the public about these toxic releases by exempting the oil and gas industry from reporting under section 313.

The petroleum industry is emitting thousands of pounds of toxic chemicals into our environment.[55] Communities large and small are adversely affected by their ignorance to the toxic substances being released into their environment. The EPA allows the industry this luxury under the exemptions to the EPCRA. It is time for the federal government to stop abdicating its duty under the EPCRA to require the oil and gas industry to report its toxic emissions.

[53] Id.
[54] Id.
[55] http://apcd.state.co.us/.

Conclusion

In order to adequately remedy the negative impacts on human health and the environment, the following recommendations must be addressed:

1) Crude oil and petroleum must be covered under the Comprehensive Environmental Response, Compensation, and Liability Act in order to protect human health and the environment from spills and leaks of hazardous and carcinogenic materials on well sites. This is the only way to currently assist overburdened federal and state programs in light of the exponential growth of oil and gas development in the United States.
2) To protect human health and the environment, oil field wastes must be regulated under the Resource Conservation and Recovery Act in order to ensure the proper handling and disposal of hazardous and carcinogenic wastes generated by oil and gas development. Otherwise, the petroleum industry will continue to dispose of oil field waste in ways that can pollute soil, surface and groundwater.
3) Hydraulic fracturing must be regulated by the Environmental Protection Agency under the Safe Drinking Water Act in order to adequately protect the United State's drinking water supply from the harmful chemicals used during this process. This recommendation includes a total ban on the use of diesel fuel as one of the additives in the hydraulic fracturing process.
4) Stormwater discharges from all oil and gas development must be regulated under the Clean Water Act by the federal government in order to provide the states with a proper foundation from which to build adequate stormwater programs that will protect human health and the environment from expanding oil and gas development.
5) Emissions from all oil and gas facilities must be aggregated under the Clean Air Act in order to ascertain the true hazardous effect on air quality. Also, hydrogen sulfide must be re-established as a hazardous air emission under the Clean Air Act in light of the current available data regarding its negative impacts on human health and the environment.
6) Because of the disruptive nature of oil and gas activities on human health and the environment, none of these activities ought to qualify for the categorical exclusion under the National Environmental Policy Act. All oil and gas activities must be assessed for impacts on the environment under the more comprehensive environmental assessment and environment impact statement in order to properly fulfill the intentions of the statute.

The petroleum industry must be made to disclose the chemicals used during the development stages under the Toxic Release Inventory within the Emergency Planning and Community Right-to-Know Act, in order to ensure that human health and the environment can be protected from these often-hazardous and carcinogenic substances.

The exemptions and exclusions described herein have been touted as necessary to the survival of the oil and gas industry in a difficult and volatile global market. However, the industry has been reporting staggering profits for years. These profits have been made at the expense of the public health and the environment. The time is ripe for sweeping legislative reforms that will bring the oil and gas industry in line with all other industries in this country.

Acknowledgements

This report was written by Renee Lewis Kosnik, Research Director of the Oil and Gas Accountability Project (OGAP), she holds a Master of Studies in Environmental Law and a Juris Doctor from Vermont Law School in South Royalton, Vermont.

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All the views expressed in this report are those of OGAP, and do not necessarily reflect the views of reviewers or funders. Any errors are the responsibility of OGAP.

About the Oil and Gas Accountability Project and Earthworks

EARTHWORKS begins our work where materials leave the earth—where we mine, drill and dig—to promote stewardship throughout the life-cycle of minerals, materials and products. Our mission is to protect communities and the environment from the impacts of destructive mineral development in the U.S. and worldwide. We fulfill our mission by working with communities and grassroots groups to reform government policies, improve corporate practices, and influence investment decisions. We work to encourage conservation, recycling, responsible materials policies, fuel efficiency, and renewable energy sources. We expose the health, environmental, economic, social and cultural impacts of irresponsible mineral development through work informed by sound science.

In 2005 OGAP merged with EARTHWORKS to create efficiencies and bolster strategic synergies and effectiveness. The merger also responded to the changing politics of oil and gas and mining issues, strengthening our ability to promote new, innovative strategies and solutions. OGAP works with people in tribal, urban and rural communities to protect their homes and the environment from the devastating impacts of oil and gas development. In our seven-year history, we have succeeded in building alliances with economically, racially and politically varied constituencies. By bringing together diverse partners to work towards a common – and critically important – goal, we strengthen these citizen efforts to bring about real, lasting change.

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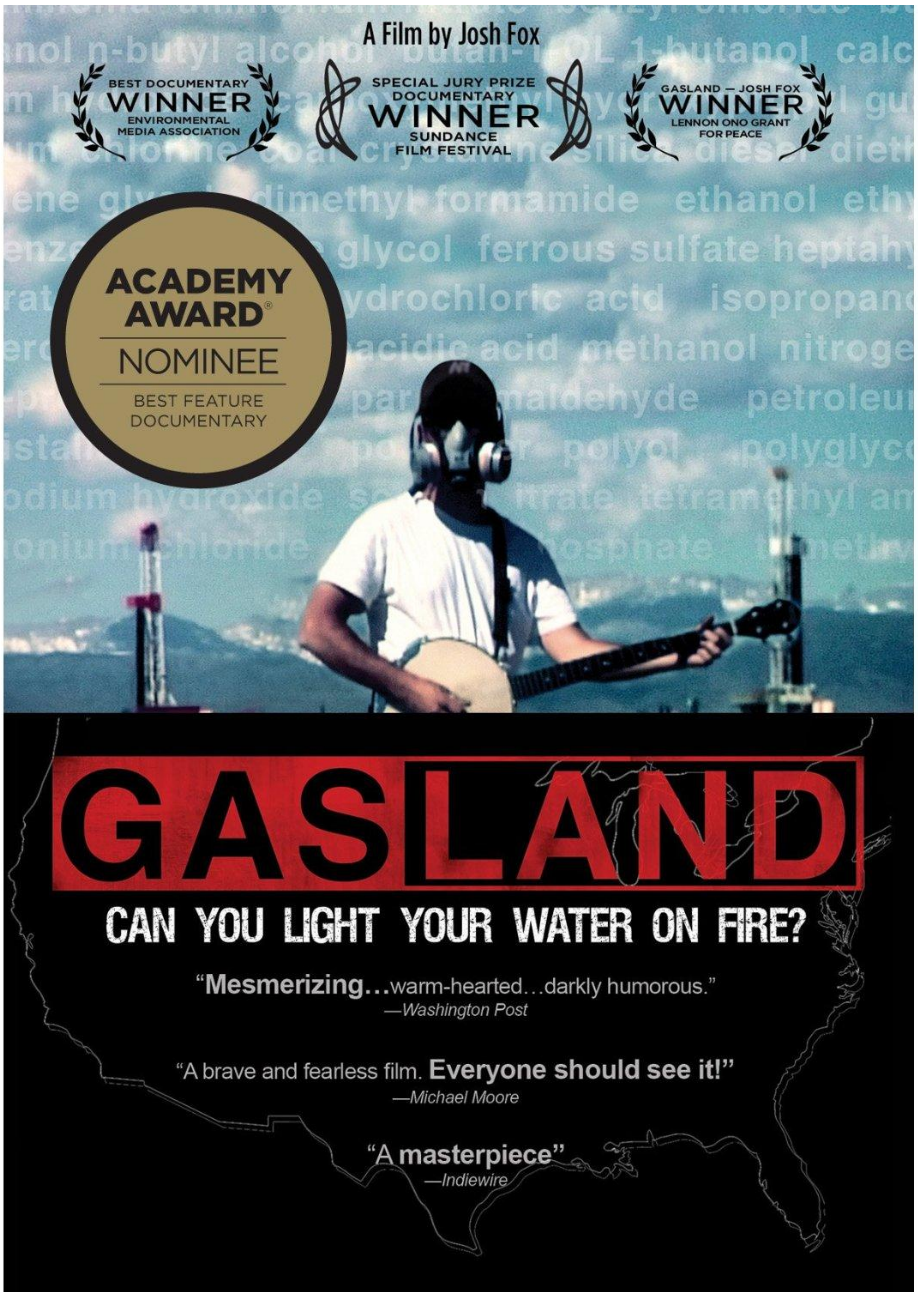
GASLAND 1 & 2 – THE MOVIES



August 2013

GASLAND 1 & 2 – THE MOVIES

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TABLE OF CONTENTS

SECTION **DESCRIPTION** **PAGE**

NOTES

- This document is a compilation of various webpages. While significant re-formatting of the material has occurred to facilitate this transition, the content is consistent with the original sources.
  - http://en.wikipedia.org/wiki/Gasland
  - http://one.gaslandthemovie.com/
  - http://one.gaslandthemovie.com/whats-fracking/affirming-gasland
  - http://one.gaslandthemovie.com/whats-fracking#faq
  - http://www.gaslandthemovie.com/
  - http://www.gaslandthemovie.com/about-the-film
  - http://www.gaslandthemovie.com/about-the-film/team
- Hyperlinks are imbedded within the document and indicated by blue font color.

GASLAND 1 & 2 – THE MOVIES

1.0 Introduction

"Gasland" and ***"Gasland 2"***, the movies, are American documentaries written and directed by Josh Fox. The films focus on communities in the United States impacted by natural gas drilling and, specifically, a method of horizontal drilling into shale formations known as slickwater fracking.

2.0 Gasland – Movie

2.1 Synopsis

In May 2008, Josh Fox received a letter from a natural gas company offering to lease his family's land in Milanville, Pennsylvania for $100,000 to drill for gas.[1] Fox then set out to see how communities are being affected in the west where a natural gas drilling boom has been underway for the last decade. He spent time with citizens in their homes and on their land as they relayed their stories of natural gas drilling in Colorado, Wyoming, Utah and Texas, among others. He spoke with residents who have experienced a variety of chronic health problems directly traceable to contamination of their air, of their water wells or of surface water. In some instances, the residents are reporting that they obtained a court injunction or settlement monies from gas companies to replace the affected water supplies with potable water or water purification kits.[2]

Throughout the documentary, Fox reached out to scientists, politicians and gas industry executives and ultimately found himself in the halls of Congress as a subcommittee was discussing the Fracturing Responsibility and Awareness of Chemicals Act, "a bill to amend the Safe Drinking Water Act to repeal a -certain exemption for hydraulic fracturing."[3] Hydraulic fracturing was exempted from the Safe Drinking Water Act in the Energy Policy Act of 2005.[4]

2.2 Production

Gasland was conceived, directed, primarily filmed, and narrated by Josh Fox. This is his first documentary and second film, his first was a narrative feature entitled *Memorial Day*. The executive producers of *Gasland* are Debra Winger and Hunter Gray; producers are Trish Adlesic, Fox and Molly Gandour; coproduced by David Roma; cinematographers are Fox and Matthew Sanchez; editor is Matthew Sanchez; supervising sound editor is Brian Scibinico;[5] animators are Juan Cardarelli and Alex Tyson; consultants are Morgan Jenness and Henry Chalfant and researchers are Molly Gandour, Barbara Arindell, Fox and Joe Levine.[6]

The documentary was made in about eighteen months. Fox began the project as a one man crew, but was joined by three other cameras at different points.[7] Matt Sanchez is credited with the structure of the film and together with Fox edited roughly 200 hours of footage to about 100 minutes.[8]

2.3 Distribution

- 2010 Sundance Film Festival
- HBO
- Currently available on Netflix
- Currently available for purchase

2.4 Accolades

2.4.1 Wins

- 2011 Primetime Emmy Award for Outstanding Directing for Nonfiction Programming (Josh Fox)
- 2010 Environmental Media Award for Best Documentary Feature
- 2010 Sundance Film Festival Special Jury Prize
- 2010 Big Sky Documentary Film Festival Artistic Vision award
- 2010 Thin Line Film Festival Audience Award
- 2010 Yale Environmental Film Festival Grand Jury Prize
- 2010 Sarasota Film Festival Special Jury Prize

2.4.2 Nominations

- 2011 Academy Award for Best Documentary Feature
- 2011 Writer's Guild Award for Best Documentary Screenplay.
- 2011 Primetime Emmy Award for Outstanding Cinematography for Nonfiction Programming (Josh
- Fox)
- 2011 Primetime Emmy Award for Outstanding Writing for Nonfiction Programming (Josh Fox)
- 2011 Primetime Emmy Award for Exceptional Merit in Nonfiction Programming (Josh Fox)

2.5 Contested Movie Components

2.5.1 Non-Favorable Analysis Overview

Not surprisingly, various entities within the natural gas industry and a state agency have taken exception with numerous components within the Gasland movie. Their responses' include, but are not limited to, the following:

- State of Colorado – Oil & Gas Conservation Commission: Gasland movie statement
  http://cogcc.state.co.us/library/GASLAND%20DOC.pdf
- "Truthland" the movie – a response to the Gasland movie
  http://www.truthlandmovie.com/
- Energy-in-Depth – search results for Gasland movie
  http://www.energyindepth.org/?s=gasland+movie

  These selected sources are previously detailed in the "Hydraulic Fracturing – Favorable Documentation" portion of the course material.

2.5.2 Affirming Gasland Debate

In direct response to the claims about the Gasland movie by Energy-in-Depth, Josh Fox presented the following "Affirming Gasland" discussion and point-by-point rebuttal on the Gasland webpage:
http://one.gaslandthemovie.com/whats-fracking/affirming-gasland

AFFIRMING GASLAND

A de-debunking document in response to specious and misleading gas industry claims against the film.

Dear audience, press, and peers:

I have been overwhelmed by the amazing, positive responses to the film. From the incredible reviews, the great HBO ratings, the effusive and impassioned response to our website and Facebook page, the powerful responses of the news media and the thousands of audience members at sold-out community screenings, I am humbled that Gasland has been so well received and is helping to bring the crisis of gas drilling in the USA to greater attention.

Even before its release, the significance of the film was not lost on the gas industry. In the March 24th edition of the Oil and Gas Journal, Skip Horvath, the president of the Natural Gas Supply Association said that Gasland is "well done. It holds people's attention. And it could block our industry."

Although I am thoroughly dismayed and disappointed in the recent attacks on the veracity of Gasland and on my credibility as a filmmaker and journalist by Energy-In-Depth and other gas-industry groups, I can't say that I am surprised.

When I was investigating gas drilling across the United States, I heard time after time from citizens that the industry disputed the citizens' claims of water and air contamination and denied responsibility for their health problems and other problems related to drilling. I now know how the people in my documentary feel, to have the things they know to be true and the questions they are raising so blatantly discounted and smeared. It is truly unfortunate that the gas-drilling industry continues to deny what is so obvious to Americans living in gaslands across the nation instead of taking responsibility for the damage they are causing.

I am issuing the following point-by-point rebuttal of their claims, not because I feel obligated to address what are clearly falsehoods and smear tactics, but to show the depth of the industry's assault on the truth and to point out their obfuscations, misleading spin on information, and attempts to shut down questions about their practices. We will be continuing to do the work necessary to have the film seen as much as possible and to offer the Gasland team's expertise as we move forward.

First, to reveal the accusers: Energy-In-Depth (E-I-D) is a PR firm/lobbying group funded by the American Petroleum Institute. It is a source of neither journalistic integrity nor educated opinion. There are no authors named on the document "Debunking GasLand," but you can learn a bit about who they are here.

We wish both E-I-D and the gas industry as a whole would behave differently towards people living in gaslands across the globe. We urge them to see the problems that they are causing and move swiftly to correct them — and if they cannot, to cease the practice of hydraulic fracturing immediately.

Please download our responses below to their claims. I hope that you, too, continue to investigate the truth of gas drilling so that you can help us protect water, air, and public health from this unregulated industry. Thanks in advance for reading this statement. I hope it will be a resource and a jumping- off point for your continued research.

Josh Fox

Notes:
1) We have gone to our amazing team of experts to Affirm Gasland. You will see a tagline of the person responding to each point. Participating in this affirmation are Barbara Arrindell, cofounder and director of Damascus Citizens for Sustainability; Ron Bishop, PhD, lecturer in chemistry and biochemistry at SUNY Oneonta; Steve Coffman, author, educator, and former chair of Committee to Preserve the Finger Lakes; Anthony R. Ingraffea, PhD, the D.C. Baum professor of engineering at Cornell University; Weston Wilson, retired EPA environmental engineer and myself; with additional comments from James Barth, member of the steering committee of Damascus Citizens for Sustainability; Laurie Spaeth, founding blogger of www.Un-NaturalGas.org; Maura Stephens, who edited.
2) The following "E-I-D" comments are in non-italicized text.
3) The following "Affirming Gasland" Comments are in italicized text.

A. (E-I-D): For an avant-garde filmmaker and stage director whose previous work has been recognized by the "Fringe Festival" of New York City, HBO's decision to air the GasLand documentary nationwide later this month represents Josh Fox's first real foray into the mainstream – and, with the potential to reach even a portion of the network's 30 million U.S. subscribers, a potentially significant one at that....

JOSH: This is the beginning of a recurring little rant on my life's work thus far, which is as artistic director of the innovative theater company International WOW. I am happy to be associated with avant-garde work, the cutting edge of the art form.

My company, International WOW, however, is far from being a fringe/unknown group. Our work has been produced all over the world and is the recipient of numerous awards and grants. Last year International WOW was nominated for a Drama Desk Award for our production Surrender, which was a collaboration with decorated Iraq War Veterans. International WOW Company has received five prestigious MAP fund grants, NEA, NYSCA and FORD foundation funding, several fellowships from the Asian Cultural Council, and many other accolades. I am very proud of the more than 25 full-length works of the company, and I think the company's innovative working methods and aesthetics are at work in Gasland.

If you want to know more about International WOW Company, please visit our website: www.internationalwow.com.

B. (E-I-D): Misstating the Law [Quoting *Gasland*] (6:05) "What I didn't know was that the 2005 energy bill pushed through Congress by Dick Cheney exempts the oil and natural gas industries from Clean Water Act, the Clean Air Act, the Safe Drinking Water Act, the Superfund law, and about a dozen other environmental and Democratic regulations. " This assertion, every part of it, is false. The oil and natural gas industry is regulated under every single one of these laws—under provisions of each that are relevant to its operations. See this fact sheet for a fuller explanation of that.

JOSH: The first major section of E-I-D's piece is a denial that the industry is exempt from most major environmental laws. This is a blatant falsehood. We will go into this in detail below, but first, let's let NRDC set the record straight. Click this link for a complete spreadsheet of the EXEMPTIONS.

WESTON WILSON: Gasland asserts that the effect of the 2005 Energy Policy Act was to remove EPA oversight from hydrofracking. It is well established that hydrofracking fell within the regulatory provisions of the Safe Drinking Water Act and that the Bush/ Cheney administration actively pushed for hydrofracking exemptions in the Energy Policy Act of 2005. Therefore, it is patently disingenuous for "Debunker" to claim otherwise.

For WESTON WILSON's extensive comments on EXEMPTIONS, please see the following extended reading section beginning on page 35.

C. E-I-D: Far from being "pushed through Congress by Dick Cheney," the Energy Policy Act of 2005 earned the support of nearly three-quarters of the U.S. Senate (74 "yea" votes), including the top Democrat on the Energy Committee; current Interior Secretary Ken Salazar, then a senator from Colorado; and a former junior senator from Illinois named Barack Obama. In the U.S. House, 75 Democrats joined 200 Republicans in supporting the final bill, including the top Democratic members on both the Energy & Commerce and Resources Committees.

STEVE COFFMAN: In his second week in office, George W. Bush created the energy task force, officially known as the National Energy Policy Development Group, with Vice President Dick Cheney as chairman. In its mission, NEPDG aimed to: "develop a national energy policy designed to help the private sector. . . ."

Only when pressed by EPA chief Christie Todd Whitman did Cheney remove a recommendation to exempt fracturing from the task force's final report. Whereupon, the Bush/Cheney Energy Bill of 2003 included a provision to exempt fracturing from EPA drinking water regulation — but Congress removed the provision from the final draft.

Whereupon, in the Energy Policy Act of 2005, Congressmen James Inhofe of Oklahoma and Joe Barton of Texas inserted language to "Amend the Safe Drinking Water Act of 1996 to exempt hydraulic fracturing related to oil and gas production . . . and, thus, exclude this practice from . . . regulations related to the protection of underground sources of drinking water."

D. E-I-D: [Quoting from *Gasland*] (6:24) "But when the 2005 energy bill cleared away all the restrictions, companies … began to lease Halliburton technology and to begin the largest and most extensive domestic gas drilling campaign in history – now occupying 34 states."

Once again, hydraulic fracturing has never been regulated under SDWA – not in the 60-year history of the technology, the 36-year history of the law, or the 40-year history of EPA. Given that, it's not entirely clear which "restrictions" in the law Mr. Fox believes were "cleared away" by the 2005 energy bill. All the bill sought to do was clarify the existing and established intent of Congress as it related to the scope of SDWA.

Interest in developing clean-burning natural gas resources from America's shale formations began to manifest itself well before 2005. The first test well in the Marcellus Shale in Pennsylvania, for example, was drilled in 2004. In Texas, the first wells in the prolific Barnett Shale formation were spudded in the late 1990s. But even before natural gas from shale was considered a viable business model, energy producers had been relying on hydraulic fracturing for decades to stimulate millions of wells across the country. The technology was first deployed in 1948.

JOSH: This is a common industry tactic, to claim that hydraulic fracturing [HF] has been used for 60 years. This is deliberately misleading.

The new hydraulic fracturing that has brought about so much attention in the last few years is different in many ways from the historic fracturing:

1) *The pressure used is much higher and the duration of the frack job is longer. Today HF employs typically 13,500 pounds of pressure per square inch, whereas earlier HF was less than 10,000 pounds per square inch.*
2) *The volume of water used: two to seven million gallons per frack, with Multi Stage Fracks lasting up to three or four days, at 1,000 gallons per minute.*
3) *The combination of HF with horizontal drilling, a huge new aspect. and,*
4) *The complexity of the chemical cocktail used in the process.*

However, the industry frequently contradicts itself, wanting to tout both the reassurance that this technique is tried and true and that it has created an innovative technology that unlocks gas that was previously not considered recoverable. The industry touts the "new technological breakthrough" of HF as unlocking the Marcellus shale in ways that could not have been done years ago.

On Chesapeake Energy's Hydraulic Fracturing "fact" site, this contradiction is evident: "Hydraulic fracturing, commonly referred to as fracing, is a proven technological advancement which allows natural gas producers to safely recover natural gas from deep shale formations. This discovery has the potential to.... [emphasis added]." Later in the same passage we get the same refrain: "Hydraulic fracturing has been used by the oil and gas industry since the 1940s..."

To READ MORE on the TECHNICAL ASPECTS of HIGH-PRESSURE FRACKING, see extended reading section starting on page 35.

E. E-I-D: The contention that current energy development activity represents the "largest … drilling campaign in history" is also incorrect. According to EIA, more natural gas wells were developed in 1982 than today. And more than two times the number of petroleum wells were drilled back then as well, relative to the numbers we have today. Also, while it may (or may not) be technically true that fracturing activities take place in 34 states, it's also true that 99.9 percent of all oil and gas activity is found in only 27 U.S. states (page 9, Ground water Protection Council report).

JOSH: This is yet another obfuscation of the facts that is disproven quickly by looking up the very chart that E-I-D references. While it is true that in 1982 there were more gas wells drilled than in 2010 (and by the way, we're not done with 2010 yet), Gasland states that since 2005 a huge upswing in drilling took place. The chart that E-I-D references in this section shows this. Between 2005 and 2009, more gas wells were drilled in the US than at any time in history.

But what is even more significant is that leasing in unconventional drilling area plays throughout the 34 states was incredibly active (follow this link and click on "drilling areas"), and that once the SDWA exemption came in, the gas industry charged forth into these areas full force and began planning for huge drilling campaigns in those regions, most notably perhaps in the Marcellus shale in NY/PA/OH/WV, the Barnett Shale in the Fort Worth area, the Haynesville Shale in Louisiana/Arkansas, and the other major shale plays.

F. E-I-D: [Quoting from *Gasland*] (32:34) "The energy task force, and $100 million lobbying effort on behalf of the industry, were significant in the passage of the 'Halliburton Loophole' to the Safe Drinking Water Act, which authorizes oil and gas drillers exclusively to inject known hazardous materials, unchecked, directly into or adjacent to underground drinking water supplies. It passed as part of the Bush administration's Energy Policy Act of 2005."

Not content with simply mischaracterizing the nature of existing law, here Fox attempts to assert that the law actually allows energy producers to inject hazardous chemicals "directly into" underground drinking water. This is a blatant falsehood. Of course, if such an outrageous thing were actually true, one assumes it wouldn't have taken five years and a purveyor of the avant-garde to bring it to light.

JOSH: This claim echoes the common industry line, "There has never been a proven case of water contamination caused by hydraulic fracturing." Industry representatives and lobbyists said this over and over again in the film. It's a carefully worded sentence that contains two major deceptions:

1. *The word "proven" — How can you prove something that has never been investigated? HF has never been investigated fully by the EPA. The fact that non-naturally-occurring chemicals specifically associated with HF fluids and drilling muds are showing up in people's water supplies is the first level of proof; E-I-D denies the testimony of the citizens. Very tricky wording, which belies the real truth. Quite deliberately.*
2. *The words "hydraulic fracturing" The industry here defines HF here as the moment underground fractures are split — and not the entire drilling process. The industry could never claim that there has never been a proven instance of water contamination due to the whole process of GAS DRILLING, but when they confine their definition to the single moment of the underground fracturing — a part of the process that has never been investigated — they can legally deny the obvious.*

E-I-D also claims here that hydraulic fracturing does not inject toxic fluids directly into drinking water supplies. Not true! Of course it does; in fact, that is the biggest problem with HF — and it is exactly what the SDWA exemption allows.

Their continual pot-shots at the avant-garde are also disappointing, not to mention puerile.

FURTHERMORE, drilling muds, which are multifunctional including acting as lubricants for the drill bit in the initial drilling process contain hazardous chemicals, They are injected directly into the aquifers as this initial drilling is into the raw earth before the well is cased. Indicators and substances related to the initial drilling and the drilling muds such as arsenic, barium, and strontium have been found in our subjects' water tests just after drilling.

Also see: http://ithaca.wishingwellmagazine.org/blogs/tompkins-weekly/2010/03/health-impactsgas-drilling-examined http://carbonwaters.org/tag/drinking-water-contamination/

WESTON WILSON: The Energy Policy Act of 2005 defines hydraulic fracturing, unless the fluids contain diesel, as not subject to the Safe Drinking Water Act. Other provisions of the SDWA prohibit *direct injection of hazardous materials directly into drinking water sources. Water underground that can be or is used for drinking water is known as an "underground source of drinking water" (USDW).*

The disingenuous E-I-D response here is that direct injection of hazardous materials was not a provision of the Energy Policy Act of 2005, but that is not the context of Josh's statement here. The context of Josh's statement is that all drillers must drill through USDWs to get to the natural gas. Josh's statement is accurate: the "Halliburton loophole" exempted HF wells from being tested under the SDWA for their mechanical integrity, which would have determined if they were adequately sealed to prevent hazardous materials from entering directly into a USDW or into an adjacent USDW (which could happen if the HF well releases methane and hazardous materials upwards into a USDW).

JOSH on fracking with diesel, a federal crime: In spite of the fact that the fracking companies were not supposed to use diesel to frack, they did it anyway. As reported by The New York Times in February 2010, "Two of the world's largest oil-field services companies [Halliburton and BJ Services] have acknowledged to Congress that they used diesel in hydraulic fracturing after telling federal regulators they would stop injecting the fuel near underground water supplies."

G. E-I-D: The subsurface formations that undergo fracture stimulation reside thousands and thousands of feet below formations that carry potable water. These strata are separated by millions of tons of impermeable rock, and in some cases, more than two miles of it.

JOSH: That target layers of fracking are far below underground drinking water sources was never contested by Gasland. We don't know why fracking chemicals and fugitive natural gas are getting into water supplies, we just know that they are. Again, there has never been a thorough nationwide investigation by a highly qualified government agency. But that is beginning to change. The nine major fracking companies are currently being investigated by the U.S. Congress. The EPA has been examining water contamination in Pavillion, Wyoming for the past year and is now scoping a major two-year study of HF at the behest of Congress.

H. E-I-D: Once again, to characterize the bipartisan 2005 energy bill as having a "loophole" for hydraulic fracturing requires one to believe that, prior to 2005, hydraulic fracturing was regulated by EPA under federal law. But that belief is mistaken. And so is the notion that the 2005 act contains a loophole for oil and natural gas. As stated, hydraulic fracturing has been regulated ably and aggressively by the states.

WESTON WILSON: But not so ably or aggressively as to prevent the well-documented oil and gas production problems in Garfield County, Colorado; *Pavilion, Wyoming; DISH, Texas; or Dimock, Bradford County,* and *Hickory, Pennsylvania. More.*

JOSH: It should be noted that generally the state DEP (Department of Environmental Protection) or DEC (Department of Environmental Conservation) or DEQ (Department of Environmental Quality) or DEQC (Department of Environmental Quality Control) does not have adequate budget or staff to investigate, inspect, or monitor HF wells — especially as they are spreading so rapidly. Exempting HF from federal law leaves this responsibility to the states that have been overwhelmed by the drilling. For example, in New Mexico there are only 18 inspectors to deal with 99,000 gas wells. It's simply not possible for so few people to track so many wells.

I. E-I-D: [Quoting *Gasland*] (1:32:34) "Diana DeGette and Maurice Hinchey's FRAC Act [is] a piece of legislation that's one paragraph long that simply takes out the exemption for hydraulic fracturing to the Safe Drinking Water Act." Here Fox is referring to the 2008 iteration of the FRAC Act, not the slightly longer (though equally harmful) 2009 version of the bill. The legislation does not, as its authors suggest, "restore" the Safe Drinking Water Act to the way it was in 2004. It calls for a wholesale re-writing of it.

JOSH: E-I-D is stating that the FRAC Act is "harmful." This is a strange choice of words when we are talking about restoring Safe Drinking Water Act protections. The SDWA aims to protect underground drinking water supplies from harmful chemical injection. So here E-I-D states that the Safe Drinking Water Act is considered "harmful" to the gas industry. (The FRAC Act and other efforts to regulate HF are in fact being advanced and negotiated currently.)

J. E-I-D: Here's the critical passage from the FRAC Act: "Section 1421(d)(1) of the Safe Drinking Water Act is amended by striking subparagraph (B) and inserting: (B) includes the underground injection of fluids or propping agents pursuant to hydraulic fracturing operations related to oil and gas production activities." Why would you need to "insert" new language into a 36-year-old statute if all you were looking to do is merely " restore" it?

JOSH: The insertion is to make it crystal clear that the bill is a reaction to the injection of fracking fluids and the thousands of documented cases of contamination.

Josh on flammable tap water and its causes – I am taking this point out of order because it is so important to the film I want to address it near the beginning of this document:

K. E-I-D claims: Mike Markham in *Gasland*]: Fox blames flammable faucet in Fort Lupton, Colo. on natural gas development. But that's not true according to the Colorado Oil & Gas Conservation Commission (COGCC). "Dissolved methane in well water appears to be biogenic [naturally occurring] in origin. … There are no indications of oil & gas related impacts to water well." (complaint resolved 09/30/08, signed by John Axelson of COGCC)

JOSH: Biogenic gas can migrate as a result of gas drilling. And hiding behind "biogenic" gas classification is yet another common industry obfuscation tactic.

E-I-D asserts that the gas that Mike Markham lights at his tap was classified as "biogenic" by the Colorado Oil and Gas Conservation Commission, so therefore the problem cannot be attributed to drilling. This is a very misleading assertion, and it is false in several ways.

A distinction is being made here between "biogenic" and "thermogenic" natural gas. "Biogenic" gas is created by decomposing organic material, and is found in pockets close to the surface. "Thermogenic" natural gas is created by intense pressure in underground rock formations and can come only from deeper layers (including shale, which are targeted by fracking). The different types of gas can be identified by isotopic tests that "fingerprint" the gas. However, gas fingerprinting simply identifies the gas. It does not identify the migratory pathway of the gas — a key omission.

Just because Mike Markham's gas is "biogenic" doesn't mean that its migration into water supplies was not caused by drilling.

I asked Dr. Anthony Ingraffea, the D. C. Baum Professor of Engineering at Cornell University, whose research for more than 30 years has involved structural mechanics, finite element methods, and fracture mechanics: "Can drilling and/or hydraulic fracturing liberate biogenic natural gas into a fresh water aquifer?"

His reply: "Yes, definitely. The drilling process itself can induce migration of biogenic gas by disturbance of previously blocked migration paths through joint sets or faults, or by puncturing pressurized biogenic gas pockets and allowing migration through an as-yet un-cemented annulus, or though a faulty cement job. The hydraulic fracturing process is less likely to cause migration of biogenic gas; however, the cumulative effect of many, closely spaced, relatively shallow laterals, each fracked (and possibly re-fracked) numerous times, could very well create rock mass disturbances that could, as noted above, open previously blocked migration paths through joint sets or faults."

So, just because the COGCC labeled the gas "biogenic" doesn't mean that they actually looked into how it got there. As Professor Ingraffea states above, there are several ways that drilling and fracking can cause biogenic natural gas to migrate into aquifers. COGCC did not conduct a hydrogeologic study to determine the migratory pathways of the gas into the water supply — despite citizens' conviction that the problems with their water happened after fracking occurred nearby. At the very top of the Gasland interview with Mike Markham and his partner, Marsha Mendenhall, they state very clearly their intense frustration with the COGCC. Holding up the jar of their contaminated water, they explain that the COGCC had ruled that their contamination had nothing to do with gas drilling. This fact is not hidden by the film.

Renee McClure, who also had flammable tap water, expressed frustration with the COGCC as well, stating: "I thought that the Colorado Oil and Gas Conservation Commission was there for the people. They are not there for the people, they are there to work and help the oil and gas companies. And I asked them—who's there for the people? And he told me, 'NOBODY, call an attorney!' "Renee McClure was also told her methane contamination was naturally occurring. Both Markham and McClure stated on the record that their water got worse after nearby fracking and gas-drilling activity had occurred. (And in both cases, water tests showed other contaminant related to oil and gas production in their water wells, which is a fact that E-I-D leaves out.)

There are striking similarities between the industry's and regulators' responses in Weld County, Colorado and Dimock, Pennsylvania. In both cases, citizens had a fundamental distrust of the state regulatory agency, and in both cases gas companies called the gas "biogenic" until the claim was either disproved or additional cases of "thermogenic" gas contamination surfaced.

<u>Widespread frustration with state agencies Like COGCC and PA DEP</u>

Frustration among citizens with their state agencies was very common in my travels, in Colorado, in Pennsylvania, in Texas, and in Arkansas. Citizens pointed out time and time again how they felt their state environmental agencies were not up to the job, or even worse, were in cahoots with the gas companies. In Dimock, Pennsylvania, we were told that Cabot Oil and Gas and DEP reps often walked in together with an air of camaraderie; in Texas, complaints about the Texas Commission on Environmental Quality (TCEQ) and the Railroad Commission were rampant. It is indeed part of the thesis of Gasland that state agencies are either overwhelmed or not to be trusted when it comes to gas drilling. Mike and Marsha make that point quite clearly. Among folks living in gaslands, state agencies are not living up to their responsibilities to protect citizens and are widely suspected of corruption.

I also experienced the same frustration with the Colorado Oil and Gas Conservation Commission (COGCC) and Pennsylvania Department of Environmental Protection. Dave Neslin, the COGCC executive director, scheduled an interview with me and then promptly canceled it when I asked him to sign a production release.

We included that refusal in the film. PA DEP secretary John Hanger said there was no contamination of Dimock's water in the beginning of his interview, but he promptly reversed his position when I offered him some Dimock water to drink, stating that the families that had been contaminated had been given replacement water by the gas companies.
<u>Biogenic/thermogenic reversal in Dimock</u>

As pointed out before, just because the gas industry says the gas is biogenic doesn't mean that it actually is.

When I got to Dimock I called Cabot Oil and Gas spokesman Ken Komoroski to ask about Dimock's flammable tap water. He gave me the same explanation, saying that Dimock's water had been flammable prior to drilling and that the gas was biogenic. A few months later the PA DEP did extensive testing that showed that the gas was in fact thermogenic. (You can see the attached PDF with PA DEP's findings on the subject and Cabot Oil and Gas's plea to DEP to not identify the gas as "Marcellus" gas.) Here is a key quote from a PA DEP internal memo on the subject.

Sent: Thursday, January 29, 2OO9 6:54 AM

To: Burch, Kelly; Bowman, Kenneth

cc: sherman, Michael D; Schwartz, Ronald; Lobins, craig; Bialosky, Donald; carmon, Mark;Bedrin, Michael; Sexton, Barbara (DEP)

Subject: RE: Stray gas incident - Dimock Twp,, Susquehanna County

"Based on the existing geochemical data set, we can conclude that the origin of the stray gases detected in the Florentino and sautner [sic] water wells (nine samples analyzed thus far: two = stray gas, seven = potential sources) is thermogenic in origin, consistent with natural gas from Devonian production. The gas found in these water wells is not consistent with microbial gas that occurs in some shallow aquifer systems."

However, Cabot Oil and Gas's first response, like the gas industry's first response to Gasland, was to try to discredit the claim. Ken Komoroski stated that Dimock residents either had gas in their water from before the drilling, which all the citizens dispute, or that somehow magically at exactly the same time as drilling started, an unrelated source of natural gas began to migrate into their water supply.

<u>Proven examples of "thermogenic" natural gas in water supplies</u>

Just because Mike Markham's gas may or may not be biogenic doesn't mean that all of the examples of lighting water on fire in the film are due to biogenic gas.

This leads me to discuss the case of Mike and Marsha and Renee's neighbors, Amee and Jesse Ellsworth, who are featured in the film just after Mike and Marsha. They light their water on fire in the film. Unlike Mike and Marsha, the methane in their water was ruled "thermogenic" by the COGCC, to have come directly from the deeper layers, i.e., from the layers targeted by gas drilling. Amee and Jesse's tests were done a year after Mike and Marsha's tests, which could indicate that thermogenic gas was pushing biogenic gas up to the surface. Biogenic would come up first into the aquifer as in Mike's 2008 test followed by Amee's thermogenic gas, tested in 2009.

What happened to theses families?:

I will state again, that in neither case did the COGCC do any real hydro-geologic surveying; they only labeled the gas as "thermogenic" or "biogenic" and then walked away, leaving Mike and Marsha, Renee, and Amee with no option but to start hauling water into their houses from a nearby municipal water source, move away and start over, or enter into a negotiation with the gas company for water.

Of the three cases, Mike and Marsha chose hauling water. They go to town once or twice a week to buy water from a coin-operated machine, as detailed in the film. Renee McClure moved out of the area, presumably because of her water and health problems in Weld County.

Amee and Jess Ellsworth chose to negotiate with the gas company and have now been silenced, compelled to sign a non-disclosure agreement. I checked in with Amee recently to see how she wa doing. She said, with regret in her voice, "I can't talk to you about gas." She can no longer talk on the record about what happened to her. I don't know the details, but I do know that she is still being delivered water by the company. She cannot speak to me or anyone about the gag order she was compelled to sign, I found out from a third party. She had to trade her silence for water. At that moment, the truth lost a very powerful and articulate voice. Without water, you cannot sell your property, and without water you cannot stay on your property. Amee and Jesse's backs were against the wall; they took the only way out of the nightmare. They sold their first amendment rights for water.

In Dimock, the water problems continue. Cabot Oil and Gas is supplying water to 32 families as ordered by PA DEP, (up significantly from the 4 families that John Hanger notes in the film). In

Hickory PA, replacement water is rampant, with some reports stating that over 200 families are receiving replacement water in exchange for non- disclosure agreements. Why should people have to sign an NDA to get clean water after a multi-billion-dollar corporation contaminates their water? Is it right for people to have to trade their silence for what should be their right?

<u>CONCLUSION on biogenic or thermogenic gas:</u>

Whether the gas is determined biogenic or thermogenic, we believe the citizens when they say the problem happened post-drilling and post-fracking. Testing of the drinking water in Dimock prior to drilling showed no gas of any kind in any significant quantities. The industry is using this biogenic/thermogenic distinction, often with the collusion of state agencies who are not properly investigating, to dispute citizen's claims of contamination, but it has no basis in science.

L. E-I-D: [following previous statement] Context from our friends at ProPublica: "Drinking water with methane, the largest component of natural gas, isn't necessarily harmful. The gas itself isn't toxic—the Environmental Protection Agency doesn't even regulate it — and it escapes from water quickly, like bubbles in a soda." (Abrahm Lustgarten, ProPublica, 4/22/09)

STEVE COFFMAN: But Debunker might not have been so snarky had he quoted the entire passage the above quote was deviously plucked from. "Drinking water with methane, the largest component of natural gas, isn't necessarily harmful. The gas itself isn't toxic -- the Environmental Protection Agency doesn't even regulate it -- and it escapes from water quickly, like bubbles in a soda.

But the gas becomes dangerous when it evaporates out of the water and into people's homes, where it can become flammable. It can also suffocate those who breathe it. According to the Agency for Toxic Substances and Disease Registry, a part of the U.S. Department of Health and Human Services, as the concentration of gas increases it can cause headaches, then nausea, brain damage and eventually death."

READ the ProPublica piece by Abrahm Lustgarten, "COLORADO STUDY LINKS METHANE in WATER to DRILLING," whence the E-I-D excerpt came, in our extended reading section starting on page 35.

M. E-I-D: Misrepresenting the Rules (1:00:56) "Because of the exemptions, fracking chemicals are considered proprietary … The only reason we know anything about the fracking chemicals is because of the work of Theo Colborn …by chasing down trucks, combing through material safety data sheets, and collecting samples."

With due respect to eminent environmental activist and former World Wildlife Fund staffer Theo Colborn, no one has ever had to "chas[e] down a truck" to access information on the materials used in the fracturing process.

That's because there's actually a much easier way to obtain that information: simply navigate to this website hosted by regulators in Pennsylvania, this one from regulators in New York (page 130), this one for West Virginia, this one maintained by the Ground Water Protection Council and the U.S. Department of Energy (page 63), and this one on the website of Energy In Depth.

JOSH: Theo's chemical lists were published at least two years before John Hanger's DEP published the list of the chemicals on the PA DEP website in the spring of 2009. Activist groups like Damascus Citizens in Pennsylvania had complained that the DEP was stating that the process used no fracking fluids, only "water and sand." Of course, after they released the list, the DEP asserted that they never said that fracking used only water and sand. Dr. Theo Colborn's research is here.

WESTON WILSON: This is Orwellian reasoning indeed — as it was not until Dr. Colborn published her data on HF fluids that these data became available in the NY Supplemental Generic Environmental Impact Statement (SGEIS). The Groundwater Protection Council (GWPC) and Department of Energy (DOE) source entitled "Shale Gas: A Primer," prepared by ALL Consultants, lists only classes of chemicals and their function in the well—there are no CAS (Chemical Abstracts Service) numbers provided by the GWPC/DOE. CAS registry numbers are unique numerical identifiers for chemical elements, compounds, polymers, biological sequences, mixtures and alloys. Yet neither the West Virginia statement cited by E-I-D, nor the E-I-D list contain CAS numbers, which are necessary to identify the chemical and its toxicity.

http://en.wikipedia.org/wiki/CAS_registry_number - cite_note-crc-1#cite_note-crc-1

Chemical Abstracts Service (CAS), a division of the American Chemical Society, assigns these identifiers to every chemical that has been described in the literature. The intention is to make database searches more convenient, as chemicals often have many names.

JOSH: Gas companies also told NY DEC that frack fluid was just water and sand.

N. E-I-D: (1:03:33) Dr. Colborn: "Once the public hears the story, and they'll say, 'Why aren't we out there monitoring'? We can't monitor until we know what they're using. There's no way to monitor. You can't."

Theo continues to investigate and discover more chemicals. Her list is up to 944.

According to environmental regulators from Josh Fox's home state of Pennsylvania, "Drilling companies must disclose the names of all chemicals to be stored and used at a drilling site... These plans contain copies of material safety data sheets for all chemicals... This information is on file with DEP and is available to landowners, local governments and emergency responders."

JOSH: Although I applaud PA DEP's disclosure of some of the fracking chemicals, its list is still incomplete and lists certain chemicals as "proprietary" (At the link, see the listing for Super Pen, among others, third page, fourth column)

O. E-I-D: Environmental regulators from Fox's adopted state of New York also testify to having ready access to this information. From the NY Dept. of Environmental Conservation (DEC) information page: "The [state] is assessing the chemical makeup of these additives and will ensure that all necessary safeguards and best practices are followed." According to the Ground Water Protection Council (GWPC), "[M]ost additives contained in fracture fluids including sodium chloride, potassium chloride, and diluted acids, present low to very low risks to human health and the environment." GWPC members include state environmental officials who set and enforce regulations on ground water protection and underground fluid injection.

WESTON WILSON: PA DEP requires, as do most states, that MSDS (materials safety data sheets) be posted on chemicals shipped and stored. The purpose of an MSDS is to provide information to a first responder, such as a fireman, in the case of spill or fire. Dr. Theo Colborn [of the Endocrine

Disruption Exchange] obtained various MSDS sheets from chemicals shipped for the purposes of HF. However, MSDS sheets do not contain CAS numbers. Dr. Colborn provided them where the chemical name was specific, but about 50 percent or so of these MSDS sheets lack a specific chemical name, and some MSDS sheets simply claim 'proprietary' status and list none of the chemicals in that container.

STEVE COFFMAN: E-I-D rightly tells us that lists of hundreds of added chemicals have recently been divulged in PA and NY. But E-I-D fails to add that the specific chemical formula of each individual well's fracking is still being held by companies as "proprietary trade secrets."

JOSH: MSDS sheets are photographed in the film, as are some of the chemicals' health effects, which include cancer and acute aquatic toxicity. Of course, what all this means is that the industry is acknowledging that they are injecting toxic chemicals in huge quantities underground. Most of this fluid stays under the ground. Only 25 to 50 percent of the toxic, non-biodegradable material is recovered. The rest is just left there, infused into the landscape forever or until it can be cleaned, which is enormously expensive and high in energy costs as well. To build a treatment plant for New York City's water supply would cost $20 billion and would cost approximately $1 million a day to run. As a Tennessee Water Fact Sheet points out, "Once groundwater becomes contaminated, it is extremely costly and sometimes impossible to clean up."

P. E-I-D: Mischaracterizing the Process (6:50) "[Hydraulic fracturing] blasts a mix of water and chemicals 8,000 feet into the ground. The fracking itself is like a mini-earthquake. … In order to frack, you need some fracking fluid – a mix of over 596 chemicals."

As it relates to the composition of fluids commonly used in the fracturing process, greater than 99.5 percent of the mixture is comprised of water and sand. The remaining materials, used to help deliver the water down the wellbore and position the sand in the tiny fractures created in the formation, are typically components found and used around the house. The most prominent of these, a substance known as guar gum, is an emulsifier more commonly found in ice cream.

STEVE COFFMAN (who fortunately has a sense of humor): Yum. Never mind that typical fracking chemicals like BE-6, Aldecide G, FDP-S798, and Borate Crosslinker J532 are carcinogenic, mutagenic, causes of chemical pneumonia, and highly toxic to aquatic organisms.

These you would find in ice cream of the Jim Jones frozen Kool-Aid variety. And a great majority of the 596 are similarly delectable!

RON BISHOP: "Where guar gum is used as a thickener, it is used along with a borax-type cross-linker and requires significant addition of biocides to prevent microbes from feasting on the guar gum. Then, when it's time to 'break' the gel, breaker additives — all of them toxic — must be used to thin the slurry so it can return from the well. A popular blend with guar gum includes "hydrotreated light petroleum distillates" (deodorized kerosene). This mixture is extremely toxic."

Q. E-I-D: From the U.S. Dept. of Energy / GWPC report: "Although the hydraulic fracturing industry may have a number of compounds that can be used in a hydraulic fracturing fluid, any single fracturing job would only use a few of the available additives [not 596!]. For example, in [this exhibit], there are 12 additives used, covering the range of possible functions that could be built into a fracturing fluid." (page 62)

WESTON WILSON: The industry can claim that 99.5 percent is sand and water or that a particular HF fluid only contains 12 chemicals, but since the industry doesn't submit any of its HF fluids for government testing due to proprietary claims, this remains an unknown by any state or the EPA. That is the point of the
FRAC Act, to require that disclosure.

Note that guar gum is food for bacteria underground, so a biocide is always used in HF fluids that contain gaur gum to prevent bacteria from fowling and clogging the well. Of the 596 chemicals on Dr. Colborn's 2009 list, approximately 2/3 lack either a CAS number or have a CAS number but lack any published toxicity information in the scientific literature (source: personal communication with Dr. Chris Poulet, ASTDR toxicologist in Denver.) Dr. Colborn's current list is just under 1000 chemicals.

R. E-I-D: As it relates to the composition of fluids commonly used in the fracturing process, greater than 99.5 percent of the mixture is composed of water and sand.

BARBARA ARRINDELL does the math: According to basic arithmetic, this 0.5% is actually 20 tons of chemicals per million gallons of water. Their 99.5% of water and sand is by weight, so even figuring the sand as weighing the same as water (to keep this simple), even though we know that it is denser (sand sinks when swirled around with water) . . . water weighs 8.35 pounds per U.S. gallon: 8.35 pounds per gallon times 1,000,000 gallons (this is the million gallons of water and sand) times .005 (this is the 0.5%) = 41,750 pounds. 41,750 pounds divided by 1 ton (2,000 pounds) = 20.875 tons of chemicals, So over 20 tons of chemicals are used with every million gallons of water.

LAURIE SPAETH: This claim takes advantage of the difference between percent by weight and percent by volume. The .5 percent to 1 percent of additives frequently cited by industry is reckoned by weight, which, given that water is denser than many of the additives, misleadingly gives the impression to the public of a lower volume of additives as a percentage of volume of water.

RON BISHOP: Typical hydrocarbon density is about 0.7 kilograms per liter; water is 1.0 Kg/L. An insidious effect of this density difference is that organic compounds in aqueous brine solutions (in flowback fluids, for example) will float to the surface. So, additives that make up 0.5 % of the bulk solution are much more concentrated at the surface of a holding pit, where some will affect the air quality of 'downwinders.'"

JOSH: A note on the deceptively named Groundwater Protection Council. During U.S. Representative Maurice Hinchey's cross-examination of Scott Kell of the GWPC before Congress in June 2004 (the hearings excerpted in Gasland), Kell was forced to admit that the GWPC takes large contributions from the oil and gas industry and, unlike true conservation/water advocacy groups, the GWPC often sides with industry. In Gasland, Scott Kell of GWPC testifies against reinstating the SDWA for HF before Congress.

Most of these fracking chemicals are highly toxic. For example, one of the chemicals used is 2 Butoxy Ethanol. 2BE. Learn about 2BE from Dr. Theo Colborn.

S. E-I-D: In the documentary, Fox graphically depicts the fracturing process as one that results in the absolute obliteration of the shale formation. In reality, the fractures created by the procedure and kept open by the introduction of proppants such as sand are typically less than a millimeter thick.

JOSH: Journalist Abrahm Lustgarten of ProPublica describes the process as "brute force," deploying "enough pressure to strip paint off of a car." But, to be clear, in the film we don't show the shale formation being obliterated. We show it being fractured: cracks open up and liquid rushes through. The fracking process is extremely violent, loud, and intense. When I have been on site during frack jobs, the noise from the trucks and equipment is deafening, and the ground rumbles and shakes. You can feel it coming up though the soles of your shoes.

T. E-I-D: (50:05) "Each well completion, that is, the initial drilling phase plus the first frack job, requires 1,150 truck trips."

Suggesting that every well completion in America requires the exact same number of truck trips is absurd. As could be guessed, the number of trips required to supply the well site with the needed equipment and personnel will vary (widely) depending on any number of factors.

As it relates to a source for Fox's identification of "1,150 truck trips," none is given – although it appears he may have derived those numbers from a back-of-the-envelope calculation inspired by a chart on page 6-142 of this document from NY DEC. As depicted on that page, the transportation of new and used water supplies, to and from the wellsite, account for 85 percent of the trips extrapolated by Fox.

JOSH: This statistic of 1,150 truck trips comes directly from the NY State Department of Environmental Conservation's Draft Supplemental Environmental Impact Statement, the agency's official projection on truck traffic.

STEVE COFFMAN elaborates: Josh Fox's figure is well within the ballpark of experience and expectations. This from NY DEC's dSGEIS (6.13.1):

Truck Traffic for a Single Pad of Eight Wells

- *Drill Pad and Road Construction Equipment 10 – 45 Truckloads*
- *Drilling Rig 60 Truckloads*
- *Drilling Fluid and Materials 200 – 400 Truckloads*
- *Drilling Equipment (casing, drill pipe, etc.) 200 – 400 Truckloads*
- *Completion Rig 30 Truckloads*
- *Completion Fluid and Materials 80 – 160 Truckloads*

- *Completion Equipment – (pipe, wellhead) 10 Truckloads*
- *Hydraulic Fracture Equipment (pump trucks, tanks) 300 – 400 Truckloads*
- *Hydraulic Fracture Water 3,200 – 4,800 Tanker Trucks*
- *Hydraulic Fracture Sand 160 – 200 Trucks*
- *Flow Back Water Removal 1,600 – 2,400 Tanker Trucks*

That's as many as 8,900 truckloads for one pad. Or an average of 1,112 truckloads per well (and, at some point, one would presume that those trucks are going to have to go back, too.)

JOSH: It should be noted here that these estimations of truck traffic were averages. I also chose not to emphasize the highest figures. I worked with the middle ground. DEC says that these companies use 400-600 truck trips for water. My figure of 1,150 comes from using the number 500 for truck trips for water, so 1,150 is the mid-range. So some frack jobs require more, some less.

U. E-I-D: Unrepresented in this chart is the enormous growth in the amount of produced water that is currently being recycled in the Marcellus – with industry in Pennsylvania reusing and recycling on average more than 60 percent of its water, according to the Marcellus Shale Coalition.

WESTON WILSON: The Marcellus Shale Coalition is an industry consortium, and its claims, generally, are theirs and theirs alone. See SourceWatch

PROFESSOR INGRAFFEA weighs in on "Recycling" and "Air Drilling": When the industry began commercial scale development in Pennsylvania about three years ago, "recycling" was not even being attempted by most companies. It is another example of the technology-come-lately approach of the industry wherein new technologies are developed only after a foreseeable problem becomes a major safety/environmental issue.

READ MORE on RECYCLING in the extended reading section starting on page 35.

V. E-I-D: According to GWPC: "Drilling with compressed air is becoming an increasingly popular 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." (page 55)

PROFESSOR INGRAFFEA: E-I-D should have included the reference for this quotation. Here it is, and note the year of publication: Singh, M. M., Jr. The Pennsylvania State University. Goodwin, Robert J. Gulf Research and Development Company. 1965. *Mechanism of Drilling Wells with Air as the Drilling Fluid.* SPE 1052-MS.

Drilling with compressed air probably *was* becoming "increasingly popular" in 1965. It is deceptive to imply that gas shale wells with total lengths of 10,000 feet or more can be drilled completely with compressed air. They can't, and [E-I-D] know it. Compressed air drilling is used only in the upper section of the vertical portion of a well.

Further, to be honest and thorough, the E-I-D review should have finished the above quotation from the GWPC report by continuing on its Page 55 to note: "Air drilling is generally limited to low pressure formations, such as the Marcellus shale in New York."

The citation of this neglected part of the complete quote is: Kennedy, J. *Technology Limits Environmental Impact of Drilling*. Drilling Contractor. July/August 2000. 33-35. Please show us your industry data from test wells in the Marcellus in New York that it is, in fact, a "low pressure formation."

Please tell us where/how you are disposing of used drilling mud and wet cuttings?

WESTON WILSON: By the way, this is a misprint by E-I-D, since page 55 of the shale primer does not discuss compressed air drilling. Page 55 deals with pits, and is referenced later in this critique by E-I-D correctly regarding pits.

BARBARA ARRINDELL: Drilling with compressed air is also highly explosive.

W. E-I-D: (51:12) "Before the water can be hauled away and disposed of somewhere, it has to be emptied into a pit – an earthen pit, or a clay pit, sometimes a lined pit, but a pit – where a lot of it can seep right back down into the ground. The vast majority of energy-producing states – 27 in total, including all the ones to which Fox travels for GasLand – have explicit laws on the books governing the type of containment structures that must be used for temporarily storing flowback water. A number of producers today choose to store this water in steel tanks, eliminating all risk of that water re-entering the surrounding environment.

GWPC (May 2009) “In 23 states, pits of a certain type or in a particular location must have a natural or artificial liner designed to prevent the downward movement of pit fluids into the subsurface. … Twelve states also explicitly either prohibit or restrict the use of pits that intersect the water table.” (page 28-29)

GWPC (April 2009): “Water storage pits used to hold water for hydraulic fracturing purposes are typically lined to minimize the loss of water from infiltration. … In an urban setting, due to space limitations, steel storage tanks may be used.” (page 55)

JOSH: Energy-In-Depth's own website features a virtual tour of a gas well which includes a waste pit. Everywhere I went, evaporation pits to hold waste were used. They are common practice in most states, as most energy producers don't "choose" to use safer means. Many pit liners I saw were leaking, full of holes and in some instances, the pit liner, along with the fluids had been ground up and buried by a backhoe when the well was put on line.

X. E-I-D: [Accusing Josh Fox/*Gasland* of] Flat-Out Making Stuff Up (53:36) “The Pinedale Anticline and the Jonah gas fields [of Wyoming] are directly in the path of the thousand year old migration corridor of pronghorn antelope, mule deer and sage grouse. And yeah, each of these species is endangered, and has suffered a significant decline of their populations since 2005.”

WESTON WILSON: E-I-D makes it claims about "endangered," which they put in quotes, since "endangered" usually refers to a specific government shorthand, meaning the word "endangered" is used only when explicitly referring to a species listed by the USFWS as officially "endangered" pursuant to Section 7 of the Endangered Species Act.

The Bureau of Land Management does consider that in Pinedale Anticline Project Area (PAPA) in Wyoming, oil and gas activities could significantly impact the sage grouse particularly by noise from drilling, which interferes with sage grouse breeding at their leks (places where male grouse call females), see http://www.blm.gov/pgdata/etc/medialib/blm/wy/fieldoffices/ pinedale/papadocs.Par.50955.File.dat/PAPA-SGNoiseRpt.pdf).

A recent report by the Wyoming Wildlife Consultants, LLC, states: "Consistent with the 2008 annual report, the 2009 data [suggest] that sage-grouse are avoiding habitats near natural gas *development with relatively high levels of activity." See: http://www.prnewswire.com/newsreleases/greater-sage-grouse-study-interim-results-released-89934752.html.*

BARBARA ARRINDELL: Greater Yellowstone herds are down 46 percent. The Jonah gas field is in the Greater Yellowstone ecosystem. It had herds of pronghorn, mule deer, and elk numbering 100,000 and was down more than 46 percent as of 2007. For at least 6,000 years, a herd of pronghorn have been migrating a 160-mile round trip, the longest land migration of any animals in the lower 48 . These sturdy animals, who survive snowstorms, coyotes, badgers, bears, subdivisions, and SUVs, may not survive the industrial zone that the Jonah fields have been transformed into by fracking: http://www.youtube.com/watch?v=H_lod2O2H2k&feature=related. Mule deer abundance steadily declined by 46 percent in the first four years of [gas] development (2000-2004) and then appeared to stabilize in the fifth year (2005). The WGFD reported a 19 percent decline in deer numbers for the entire herd following the severe 2003-2004 winter, leading to the conclusion that the additional 27 percent reduction in the study area is likely the result of a combination of emigration and reduced survival rates. Read more from the summary at http://www.ourpubliclands.org/resources /SawyerSummary.

This linked from scientific studies on that page: http://www.ourpubliclands.org/resources are links to a dozen studies of the degradation of populations of big game and other wildlife, and in particular mule deer, sage grouse, different kinds of fish, etc. Look at the summaries and then the full articles. They are quite clear and well written.

Y. E-I-D: [Quoting *Gasland*] (8:07) “And now they’re coming east. They’re proposing 50,000 gas wells along a 75-mile stretch of the Delaware River and hundreds of thousands more across New York, Pennsylvania, Ohio and West Virginia. From 1972 until now – my whole life – all of this has been protected.”

Not even the most optimistic scenario for future development in the Marcellus Shale in general, or along the Delaware River in particular, comes anywhere close to 50,000 natural gas wells. A recent study by Penn State Univ. projects that by the year 2020, producers will have developed 3,587 shale gas wells. A study conducted for policymakers in the Southern Tier of New York predicted a maximum of 4,000 wells for that region.

Where Fox comes up with his 50,000 figure is unknown. The protections to the area apparently in place since 1972 to which he refers are also unknown (19:27) “One thing was resoundingly clear: If the industry’s projections were correct, then this would be the end of the Catskills and the Delaware River Basin as we knew it. And it would mean a massive upheaval and redefinition of all of New York State and Pennsylvania.”

According to the Energy Information Administration, Pennsylvania is already home to 55,631 active natural wells; New York, according to DEC, is home to roughly 14,000. Again, even assuming the most active development scenario, Marcellus wells are expected to account for less than 10 percent of all wells in these two states over the next 10 to 20 years – not exactly the type of dramatic “upheaval” and “redefinition” that Fox suggests in his film.

JAMES BARTH: Andrew Maykuth, in the article "Gas Drilling Going Deep" published in the Philadelphia Inquirer on March 14, 2010, writes the lease-holding acreage for the 18 top gas companies in the Marcellus Shale area amounts to 13,717 square miles under control of these lease companies.

Chesapeake Energy Corporation, among other industry sources, has claimed that eight horizontal wells on one pad per square mile is a current optimum production plan. Indeed, in western Pennsylvania, this is being borne out by the first few years of Marcellus drilling. These figures are initial, and conservative, extraction averages.

As we have seen, the industry revises as it learns, and things change, and that normally results in an increase, not a decrease, in numbers.

Even if only one-half of that leased acreage is drilled at that rate, it would result in 54,868 wells. And again, this is for only the top 18 gas companies out of a much larger number that are operating in the Marcellus Shale.

On a separate note, Steve McConnell, writing in the Wayne Independent on January 23, 2009 ("Oregon Township May See Natural Gas Drilled"), referred to the partnership between Chesapeake and StatoilHydro: “The companies will also enter a strategic alliance to explore natural gas deposits worldwide. In Marcellus, the companies could develop between 13,500 and 17,000 horizontal wells *during the next 20 years, covering more than 32,000 leases in Pennsylvania, New York, West Virginia and Ohio." This stated goal by Chesapeake alone wildly contradicts the 3,587 figure. Mr. Fox's projection has nothing to do with the year 2020.*

Energy-In-Depth is misleading, to say the least.

As to the upper Delaware River Basin, the four counties that make up the acreage in the basin — Delaware, Sullivan, Wayne and Pike — total 3,712 square miles. According to Professor Anthony Ingraffea, who has a PhD in rock fracture mechanics, has taught at Cornell for 33 years, and who developed computer simulations on hydraulic fracturing for Sclumberger, Exxon, the Gas Technology Institute, and the National Science Foundation over a 20-year period, calculated that we can expect an average of eight directional wells per square mile, over 70 percent of the land. He has based his calculations on the numbers provided by Chesapeake and Professor Terry Engelder of Penn State. This conservative, initial estimate would amount to 20,787 horizontal wells in these four counties of the upper Delaware River Basin alone.

Recently, Deborah Goldberg, the lead attorney for Earthjustice, attended a forum sponsored by Energy Vision. Ms. Goldberg quoted David Spigelmyer, a vice president of government relations for Chesapeake, as saying the company is considering increasing the optimum average number of horizontal wells to 18 per pad, per square mile. If this revision were to take place, then development over the same area would increase to 46,771 wells.

The point is, everyone is projecting numbers, and the industry itself has changed them radically over the past two years. Who is to say that only 70 percent of the land will be drilled in this fashion?

STEVE COFFMAN: Another recent study by Penn State University projects the Marcellus Shale to be more than 10 times as big as the Texas Barnett Shale, which already has more than 10,000 active wells. Similarly, Anthony Ingraffea predicts 80,000 wells in New York and 100,000 in Pennsylvania. Sierra Club member Carl Arnold, in a press conference speech to promote a moratorium on hydrofracking (June 11, 2010), said, "We can expect, conservatively, about 65,000 wells drilled across the Southern Tier. The Hudson Valley Business Journal states that an estimated 200,000 wells will be sunk."

Z. E-I-D: (31:32) "In 2004, the EPA was investigating a water contamination incident due to hydraulic fracturing in Alabama. But a panel rejected the inquiry, stating that although hazard materials were being injected underground, EPA did not need to investigate."

JOSH: This voiceover was corrected before Gasland's release on HBO. Note that the only correction was to the scope of the EPA study. EPA was investigating water contamination incidents across the country, not only in Alabama. The court case is mentioned below in Weston Wilson's extensive comments on the exemptions.

READ MORE on EXEMPTIONS in the extended reading section starting on page 35.

AA. E-I-D: No record of the investigation described by Fox exists, so E-I-D reached out to Dr. Dave Bolin, deputy director of Alabama's State Oil & Gas Board and the man who heads up oversight of hydraulic fracturing in that state. In an email, he said he had "no recollection" of such an investigation taking place.

That said, it's possible that Fox is referring to EPA's study of the McMillian well in Alabama, which spanned several years in the early- to mid-1990s. In 1989, Alabama regulators conducted four separate water quality tests on the McMillian well. The results indicated no water quality problems existed. In 1990, EPA conducted its own water quality tests, and found nothing.

In a letter sent in 1995, then-EPA administrator Carol Browner (currently, President Obama's top energy and environmental policy advisor) characterized EPA's involvement with the McMillian case in the following way: "Repeated testing, conducted between May of 1989 and March of 1993, of the drinking water well which was the subject of this petition [McMillian] failed to show any chemicals that would indicate the presence of fracturing fluids. The well was also sampled for drinking water quality, and no constituents exceeding drinking water standards were detected."

JOSH:
As stated earlier, fracking in the 1980s and '90s was very different from fracking now; therefore, results from testing between '89 and '93 is not relevant to looking at the widespread contamination today.

READ more on HIGH-PRESSURE FRACKING in the extended section starting on page 35.

BB. E-I-D: (1:28:06) "Just a few short months after this interview, the Pennsylvania Department of Environmental Protection suffered the worst budget cuts in history, amounting to over 700 staff either being fired or having reduced hours and 25 percent of its total budget cut."

DEP press release, issued January 28, 2010: "Governor Edward G. Rendell announced today that the commonwealth is strengthening its enforcement capabilities. At the Governor's direction, the Department of Environmental Protection will begin hiring 68 new personnel who will make sure that drilling companies obey state laws and act responsibly to protect water supplies. DEP also will strengthen oil and gas regulations to improve well construction standards."

BARBARA ARRINDELL: See this link for how many firings and total cuts: http://republicanherald.com/news/environmentalprotection-suffers-deep-state-budget-cuts-1.338592 http://www.pennbpc.org/senate-budget-calls-deep-sweeping-cuts has comparison of % of various agency cuts. Most other agencies were cut much less drastically than the DEP.

JOSH: The film was finished January 20, 2010, eight days before Rendell's press release, above. However, as Barbara notes below, it is not clear whether or not new staff has actually been hired.

BARBARA ARRINDELL: PA DEP has its budget cut again - see here - Attacks on Weston Wilson, EPA

JOSH: Herein follows a series of attacks on Weston Wilson, whom I consider to be a true American hero. He risked his job and reputation by pointing out the flaws of the 2004 EPA report on hydraulic fracturing. The foresight he exhibited in blowing the whistle on that report is evident by how much widespread contamination as well as widespread concern hydraulic fracturing is causing today.

"WESTON WILSON Defends Himself" in the extended reading section starting on page 35.

CC. E-I-D: Dunkard Creek: Fox includes images of dead fish along a 35-mile stretch of Dunkard Creek in Washington Co., Pa.; attributes that event to natural gas development. (01:23:15) Fox's attempt to blame the Dunkard Creek incident on natural gas exploration is contradicted by an EPA report – issued well before GasLand was released – which blamed the fish kill on an algal bloom, which itself was fed by discharges from coal mines.

JOSH: EPA ruled that Dunkard Creek was killed by chronic exposure to mine drainage. Those mines have been draining to the creek for decades. So what changed, suddenly, to kill off the creek? EPA is overlooking the testimony of several residents who claim that gas-drilling waste was being dumped into those mines just before the fish kill. Gas-drilling wastewater is highly saline and can cause an algae bloom like the one that killed Dunkard Creek.

READ MORE on DUNKARD CREEK in the extended reading section starting on page 35.

DD. E-I-D: Lisa Bracken: Fox blames methane occurrence in West Divide Creek, Colo. on natural gas development.

That assertion has also been debunked by COGCC, which visited the site six separate times over 13 months to confirm its findings: "Stable isotopes from 2007 consistent with 2004 samples indicting gas bubbling in surface water features is of biogenic origin." (July 2009, COGCC presentation by Margaret Ash, environmental protection supervisor)

JOSH: E-I-D is in contradiction to the facts. Geoffrey Thyne's detailed investigation of the gas in Divide Creek shows it to be thermogenic in nature and therefore could not be shallow gas. Thyne is a geologist and an academic with three decades of fieldwork and experience as a research scientist in the oil and gas industry, including the last 13 years at Colorado School of Mines in Golden. See this report http://www.highbeam.com/doc/1G1-115967938.html

EE. E-I-D: Email from COGCC supervisor to Bracken: "Lisa: As you know since 2004, the COGCC staff has responded to your concerns about potential gas seepage along West Divide Creek on your property and to date we have not found any indication that the seepage you have observed is related to oil and gas activity." (email from COGCC's Debbie Baldwin to Bracken, 06/30/08)

JOSH: Geoffrey Thyne's hydro-geologic study contradicts this. It shows very clearly that the gas in Divide Creek was thermogenic gas, and it diagrams the migratory pathway from the producing *layers to the creek via natural fissures widened by fracking. Thyne concludes: "The methane in Divide Creek is primarily thermogenic and essentially identical to produced gas." He also adds: "long-term ecological effects are unknown."*

Additionally Thyne examines Garfield County's increasing problem of water contamination as gas drilling increases in the area: http://s3.amazonaws.com/propublica/assets/methane/thyne_review.pdf.

FF. E-I-D: Calvin Tillman: Fox interviews mayor of DISH, Texas; blames natural gas development, transport for toxins in the air, benzene in blood.

Tillman in the press: "Six months ago, nobody knew that facilities like this would be spewing benzene. Someone could come in here and look at us and say, 'You know what? They've sacrifice you. You've been sacrificed for the good of the shale.'" (Scientific American, 3/30/10)

A little more than a month later, Texas Dept. of State Health Services debunks that claim: "Biological test results from a Texas Department of State Health Services investigation in Dish, Texas, indicate that residents' exposure to certain contaminants was not greater than that of the general U.S. population." (DSHS report, May 12, 2010)

More from the agency: "DSHS paid particular attention to benzene because of its association with natural gas wells. The only residents who had higher levels of benzene in their blood were smokers. Because cigarette smoke contains benzene, finding it in smokers' blood is not unusual."

JOSH: E-I-D is misstating the facts as well as spinning the results of this test to their purpose. The Texas DSHS report shows that of the 15 hazardous chemicals reported in the initial DISH Air Quality Study, that 50 percent of the people in DISH had levels elevated above what are over the standard for the United States.

Wilma Subra, MacArthur Foundation Genius Award-winning chemist and first responder analyzed the new data at a recent public meeting: "According to DSHS, 50 percent of the people in DISH have levels of chemicals associated with compressor station and pipeline emissions over the general population of the United States in their blood, urine and tap water.

"Half the population is a huge percentage for people being exposed to the chemicals that are being released in DISH. And the chemicals that were found in the blood, the urine, and in the tap water are the same chemicals that are being found in the air in DISH. They found benzene in six people, and DSHS are saying that those people are smokers. Five of those were smokers. But they are trying to dismiss all of the chemicals in the 50 percent of DISH residents affected as being associated with smoking. This is not the case, it wasn't just benzene; 15 of the chemicals in the blood were over the standard for the United States. Ten of those 15 chemicals were more prevalent in nonsmokers than smokers. Two were equal in nonsmokers and smokers, and only three of the 15 chemicals were higher in smokers than nonsmokers. So it is not the issue that the people of DISH who smoke who have high concentrations of these chemicals in their blood and in their urine. The issue is 50 percent of the people in DISH have concentrations of those 15 chemicals over the average in the United States."

To READ more on DISH and the TCEQ, see section starting below.

SUPPLEMENTAL READING SECTION STARTS HERE

More on EXEMPTIONS from WESTON WILSON, EPA

The Safe Drinking Water Act requires EPA to promulgate regulations for states to administer these provisions of the law in order to protect underground sources of drinking water. However, although the SDWA gave the EPA the authority to regulate underground injection practices, Congress also directed that the EPA should not prescribe unnecessary regulation on oil- and gas-related injection. Therefore, after the Safe Drinking Water Act passed, the EPA erroneously took the position that hydraulic fracturing did not fall within the regulatory definition of underground injection as provided in the Act.

In 1997 the 11th Circuit Court of Appeals laid the matter to rest when it conclusively ruled in LEAF v EPA, 118 F.3d 1467 (11th Cir. 1997) that hydraulic fracturing activities constituted "underground injection" under Part C of the SDWA.

As a result of the court's ruling, in 1999 the state of Alabama amended its rules and made hydrofracking subject to the provisions of Part C of the SDWA by requiring Class II permits for each hydrofracking well.

Cheney's Halliburton (a prime developer and leading practitioner of hydraulic fracturing) began lobbying Washington to exempt fracturing from regulation under the Safe Drinking Water Act. Then in 2001, during his second week in office, George W. Bush created the Energy Task Force, with Vice President Dick Cheney as chairman. The mission of the task force aimed to "develop a national energy policy designed to help the private sector." Its final report included a recommendation to exempt fracturing from regulation. Cheney removed the exemption from the draft only after being pressed by EPA chief Christie Whitman. The exemption surfaced again in the Bush/Cheney Energy Bill of 2003 which did not pass, and reemerged one final time, in the Energy Policy Act of 2005, thanks, in part, to the efforts of Congressmen James Inhofe of Oklahoma and Joe Barton of Texas. To avoid the effect of the ruling in LEAF v EPA, Sec 322 of the Act specifically provides that the term "underground injection" excludes the underground injection of fluids pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities. This clause from the law is actually photographed in Gasland at 31:42.

The 2005 Energy Policy Act also altered the Clean Water Act stormwater provisions. Pub.L. No. 109 58, § 323, 119 Stat. 694 (codified as amended at 33 U.S.C. § 1362(24). Section 323 modified the Clean Water Act's definition of an oil and gas exploration and production activity to include oil and gas construction activities. Because the Clean Water Act mandates that the EPA not require a stormwater permit for oil and gas exploration and production activities, it has been argued that the change in the Energy Policy Act of 2005 excluded oil and gas construction activities from stormwater permit coverage, without regard of the size of acreage disturbed.

Previous laws exempted oil and gas drilling, known as oil and gas exploration and production, from Superfund (CERCLA) and RCRA (hazardous waste). CERCLA includes substances that are elements of petroleum as hazardous in Section 101(14), yet crude oil and petroleum are specifically exempt from coverage under the last clause of the section. Thus, hazardous chemicals that would otherwise fall under the ambit of CERCLA are immune from the statute when encompassed in petroleum or crude oil. Likewise, the Solid Waste Disposal Act (SWDA) of 1980 exempted oil field wastes from Subtitle C of the RCRA.

Oil and gas drilling is not typically covered by Clean Air Act permitting since EPA's CAA regulations do not allow EPA to aggregate or group a set of wells as a single source of air emissions. EPA has proposed rules that if promulgated would allow EPA and the states to aggregate air emissions coming from one company when the facilities are connected to one set of piping. Some oil and gas machines emit large enough air emissions to be subject to air permit requirements, for example gas dehydradation units emitting over 10 tons per year of volatile organic compounds (VOCs) and gas compressions engines emitting over 50 tons of NOx per year.

However, the industry remains mostly unregulated under this statute by using many smaller compressors and dehydrators which individually emit less VOCs than the limits. If these units were to be aggregated and counted as one larger source (which they should be, in our view) the regulations would be in effect. In addition, neither the diesel engines used to drill nor the volatiles that come off the reserve pits are subject to CAA permit regulations.

For a more complete list of these exemptions please see the following websites:
http://www.ewg.org/reports/Free-Pass-for-Oil-and-Gas/Oil-and-Gas-Industry-Exemptions
http://www.earthworksaction.org/pubs/PetroleumExemptions1c.pdf
http://www.nrdc.org/land/use/down/contents.asp
http://www.nrdc.org/media/2007/071031.asp

The Energy Policy Act negated the effect of the Alabama LEAF case by expressly defining HF as not subject to the SDWA, provided that HF fluids did not contain diesel; HF that contains diesel remains subject to SDWA limitations.

HIGH-PRESSURE FRACKING
From Pumps and Systems: http://www.pump-zone.com/upstream-pumping/frac-pumps/the evolution-of-hydraulic-fracturing-and-its-effect-on-frac-pump-technology.html

Up to the early 2000s, frac pumps traditionally came in two types, triplex or quintuplex, and ranged in horsepower capacity from 1,300 to 2,000 bhp. The majority of fracturing operations took place on gas wells, almost entirely vertical in nature, requiring only one or two fracturing stages to complete the stimulation process. Being dependent on the formation's geologic makeup, pressure *requirements were most often less than 10,000 psi. Pump design advancements during this time period were minimal. Pumps that had operated successfully for decades were capable of meeting the pressure and flow rate demands of the time.*

The first dynamic shift in operation requirements for frac pumps occurred in the early 2000s with the widespread commercialization of the Barnett Shale unconventional resource play. The Barnett Shale represented a dramatic shift in pumping requirements, with horizontal drilling used for the first time on a wide scale as pumping pressures and operating times increased. This harsher pumping environment demanded stronger pumps capable of operating at pressures of 9,000 psi and pumping intervals of more than 8 hours. During the drilling boom of 2006 through 2008, well service companies in the Barnett Shale were pumping at nearly all hours of every day.

With the low permeability of these newer premium shale gas formations, new fracturing techniques have been developed in recent years to increase production rates to overcome the high costs of drilling and completion. Horizontal drilling and its associated multistage fracturing techniques have become the norm as shale formations have now become the leading sources of natural gas in North America. At the time of the writing of this article, the horizontal rig count is at an all time high, 659 rigs, or 49 percent of all U.S. operating rigs, up from 37 percent just one year ago, according to Baker Hughes.

The Haynesville Shale has put increased pressure on pumping equipment due to the severe pumping requirements of the wells. The average Haynesville wells are currently being fracced at pressures around 13,500 psi with frac stages numbering as high as 20 per well. In the Barnett, a pump may operate onsite for 6 to 8 hours, complete the job and then be returned to the shop for maintenance before being sent out on another job. In the Haynesville Shale, however, hydraulic fracturing operations might last several days with continuous pumping intervals of 3 to 4 hours and only a limited window between stages for rapid maintenance procedures while the next frac stage is prepared. These difficult operating conditions have required operators to place upwards of 50 percent spare horsepower capacity onsite to instantly replace any equipment that may fail during operation, whether it is the engine, transmission or pumping system. In addition to increased pressure requirements, Haynesville wells often require extremely hard synthetic proppant (sand).

The new synthetic proppant, such as bauxite, wear pump expendable components and fluid ends at increasingly rapid rates.

The Haynesville Shale represents a major challenge for frac pump manufacturers. Pumping service companies demand a pump that can operate in a greater working envelope with no sacrifice on pump lifespan. Pump manufacturers are currently developing products to meet these challenging demands through innovative design features and new developments in pump expendable fabrication.

The challenge is to provide greater reliability and maintenance predictability, reducing the product downtime at frac sites and the user's need to have significant excess pumping equipment available to ensure continuity of pumping in the unlikely event of equipment failures. Manufacturers are responding to these requirements by evolving existing, well-established products, and in parallel, integrating new clean-sheet innovations and design programs with the latest computer analysis and simulation tools. Design engineers must further enhance the mechanical integrity of the frac pump to support higher pumping pressures, ensuring longer times between maintenance events, and making the maintenance activity itself safer, easier and faster.

For instance, one manufacturer has taken an existing frac pump and completly redesigned the power frame geometry, allowing an increase in rated maximum rod load while at the same time reducing its weight. The strength of the steel alloy forging used to manufacture the fluid cylinder was enhanced to provide greater fatigue life, while the geometry of the fluid end was further optimized to increase the rigidity. The pump's stay-rods were completely redesigned to reliably accommodate the additional loads. The increase in rod load allowed the pump to be comfortably rated at 2,400 bhp.

This new horsepower capability was confirmed through intensive durability testing during which the pump was subjected to nearly 10 percent above the rated loads for much of the test's duration. The cylinder spacing, crankshaft stroke and all the geometry around expendable components was untouched during the redesign to ensure that the changes had no impact on currently accepted maintenance processes. This also allows the fluid end assembly to be retrofitted onto older power ends.

As the global demand for natural gas continues to grow, new pumping technologies must be developed to ensure service companies can efficiently operate in more intense geological formations. Innovation has always been the key to success in the oilfield.

Entire, in-context ProPublica piece by Abrahm Lustgarten, "COLORADO STUDY LINKS METHANE in WATER to DRILLING"

Jesse Ellsworth thought something was wrong with his water when it began to smell funny and popped out of his faucet in bursts. Then, in February, the Fort Lupton resident launched an experiment: he flipped on the kitchen tap and took a cigarette lighter to the stream. As flint sparked steel, the water lit on fire like a torch.

Ellsworth is one of at least 29 residents in small farming communities northeast of Denver who have asked either the energy companies or the Colorado Oil and Gas Conservation Commission to test for natural gas in their water wells.

Now the commission is trying to figure out how the gas got there. Are some of Weld County's 13,957 gas wells leaking methane into drinking water? Or is methane seeping into the water naturally, as it has done from time to time over the years?

So far, officials have determined that at least nine of those contamination cases are not drilling related; they are likely the result of a water well intersecting with gas underground. But the Ellsworth's well -- which has stronger evidence tying it to drilling -- remains a mystery.

"This one I think is best characterized as an isolated circumstance," said David Neslin, director of the COGCC, "We can't, sitting here today, say 'Yes' that this is coming from somebody's gas well."

While the search for clues continues in Weld County, investigations about methane contamination in Garfield County and other parts of the country have clearly tied the contamination to energy development, strengthening arguments across the country that drilling can put drinking water at risk.

Near Cleveland, Ohio, a house exploded in late 2007 after gas seeped into its water well. The Ohio Department of Natural Resources later issued a 153-page report that blamed a nearby gas well's faulty cement casing and hydraulic fracturing -- a deep-drilling process that shoots millions of gallons of water, sand and chemicals into the ground under explosive pressure -- for pushing methane into an aquifer and causing the explosion.

In Dimock, Pa., where drilling recently began in the mammoth Marcellus shale deposit, several drinking water wells have exploded and nine others were found with so much gas that one homeowner was told to open a window if he planned to take a bath. In February, the Pennsylvania Department of Environmental Protection charged Cabot Oil & Gas with two violations that it says caused the contamination, theorizing that gas leaked from the well casing into fractures underground.

Industry representatives say methane contamination incidents are statistically insignificant, considering that 452,000 wells produced gas in the United States last year. They point out that methane doesn't necessarily come from gas wells -- it's common in nature and can leak into water from biological processes near the surface, like rotting plants.

The industry also defends its construction technology, saying it keeps gas and drilling fluids -- including any chemicals used for hydraulic fracturing -- safely trapped in layers of steel and concrete. Even if some escapes, they say, thousands of feet of rock make it almost impossible for it to migrate into drinking water aquifers. When an accident happens, the blame can usually be traced to a lone bad apple -- some contractor who didn't follow regulations, they say. Those arguments helped the gas drilling industry win rare exemptions from the Safe Drinking Water Act and the Clean Water Act when Congress enacted the 2005 Energy Policy Act.

Now an exhaustive examination of a methane problem on Colorado's Western Slope is offering a strong scientific repudiation of that argument. Released in December by Garfield County, the report concludes that gas drilling has degraded water in dozens of water wells.

The three-year study used sophisticated scientific techniques to match methane from water to the same rock layer -- a mile and a half underground -- where gas companies are drilling. The scientists didn't determine which gas wells caused the problem or say exactly how the gas reached the water, *but they indicated with more clarity than ever before that a system of interconnected natural fractures and faults could stretch from deep underground gas layers to the surface. They called for more research into how the industry's practice of forcefully fracturing those deep layers might increase the risk of contaminants making their way up into an aquifer.*

"It challenges the view that natural gas, and the suite of hydrocarbons that exist around it, is isolated from water supplies by its extreme depth," said Judith Jordan, the oil and gas liaison for Garfield County who has worked as a hydrogeologist with DuPont and as a lawyer with Pennsylvania's Department of Environmental Protection. "It is highly unlikely that methane would have migrated through natural faults and fractures and coincidentally arrived in domestic wells at the same time oil and gas development started, after having been down there ...for over 65 million years."

The Garfield County analysis comes as Congress considers legislation that would toughen environmental oversight of drilling and reverse the exemptions enjoyed by the gas companies. Colorado has already overhauled its own oil and gas regulations, despite stiff resistance from the energy industry. The new rules, which went into effect earlier this month, strengthen protections against, among other things, methane contamination.

Drinking water with methane, the largest component of natural gas, isn't necessarily harmful. The gas itself isn't toxic -- the Environmental Protection Agency doesn't even regulate it -- and it escapes from water quickly, like bubbles in a soda.

But the gas becomes dangerous when it evaporates out of the water and into people's homes, where it can become flammable. It can also suffocate those who breathe it. According to the Agency for Toxic Substances and Disease Registry, a part of the U.S. Department of Health and Human Services, as the concentration of gas increases it can cause headaches, then nausea, brain damage and eventually death.

The Garfield County report is significant because it is among the first to broadly analyze the ability of methane and other contaminants to migrate underground in drilling areas, and to find that such contamination was in fact occurring. It examined over 700 methane samples from 292 locations and *found that methane, as well as wastewater from the drilling, was making its way into drinking water not as a result of a single accident but on a broader basis.*

As the number of gas wells in the area increased from 200 to 1,300 in this decade, methane levels in nearby water wells increased too. The study found that natural faults and fractures exist in underground formations in Colorado, and that it may be possible for contaminants to travel through them.

Conditions that could be responsible include "vertical upward flow" "along natural open-fracture pathways or pathways such as well-bores or hydraulically-opened fractures," states the section of the report done by S.S. Papadopulos and Associates, a Maryland-based environmental engineering firm specializing in groundwater hydrology.

The researchers did not conclude that gas and fluids were migrating directly from the deep pockets of gas the industry was extracting. In fact, they said it was more likely that the gas originated from a weakness somewhere along the well's structure. But the discovery of so much natural fracturing, combined with fractures made by the drilling process, raises questions about how all those cracks interact with the well bore and whether they could be exacerbating the groundwater contamination.

"One thing that is most striking is in the area where there are large vertical faults you see a much higher instance of water wells being affected," said Geoffrey Thyne, the hydrogeologist who wrote the report's summary and conclusion. He is a senior research scientist at the University of Wyoming's Enhanced Oil Recovery Institute, a pro-extraction group dedicated to tapping into hardto- reach energy reserves.

The report, referred to as the Garfield County Hydrogeologic Study, has been met with cautious silence by the industry and by its regulators.

The Colorado Oil and Gas Conservation Commission, the state's regulatory body, would not respond to questions from ProPublica because it hasn't thoroughly analyzed the data behind the November report, said its acting director, David Neslin.

Neither the Colorado Oil and Gas Association nor Encana, the Canadian energy company that drills in the study area, would comment on the Garfield County report. Both referred questions to Anthony Gorody, a Houston-based geochemist who specializes in oil and gas issues and frequently is employed by the energy industry.

Gorody dismissed the report's conclusions as "junk science."

"This is so out of whack. There are a handful of wells that have problems. These are rare events," said Gorody, president of Universal Geosciences Consulting. "They are like plane crashes – the extent tends to be fairly limited. I do not see any pervasive impact."

Most of the methane in the study area, Gorody said, came from shallow gas-bearing rock or decaying matter near the surface -- not from the deep gas produced by the energy industry. He criticized the report's methodology, saying the way that researchers linked the stray gas with the deep gas formations was speculative at best.

Thyne, standing by his report, said researchers had traced the origin of the gas by conducting the equivalent of a forensic investigation, analyzing its isotopic signature, or molecular fingerprint. The molecular structure showed that most of it was thermogenic, meaning it matched the deeply buried deposit where gas was being drilled, called the Williams Fork Formation. A minority of the samples were difficult to identify by this method, so Thyne used another scientific process to study them. He is confident they, too, were thermogenic in origin.

In most cases, the study couldn't pinpoint the exact pathway the contaminants had used to travel a mile and a half up into the drinking water aquifer. So Thyne could only reason the possibilities.

The methane could be seeping into water wells through natural fractures, he said, or through leaks in the well casings or cement, or from the well heads.

When a pipe extends 8,000 feet below the earth's surface, he said, "there are numerous potential leak points along the way. So is it leaking at 8,000 feet and coming up a well bore, a natural fault or fracture? Or is it leaking 500 feet from the surface? We don't know."

The most plausible explanation, Thyne said, is that the same type of well casing and cementing issues that had proved problematic in Ohio and are suspected in Pennsylvania were presenting problems in Colorado too.

"The thesis is that because of the way the wells are designed they could be a conduit," said Garfield County's Jordan, who commissioned the report.

Jordan worries that the methane leaks could be a sign of worse to come.

"We suspect the methane would be the most mobile constituent that would come out of the gas fields. Our concern is that it's a sort of sentinel, and there are going to be worse contaminants behind it," she said. "It's not just sitting down there as pure CH4 (methane). It's in a whole bath of hydrocarbons," she said, and some of those "can be problematic." [end]

MORE on RECYCLING of "PRODUCED" WATER:

PROFESSOR INGRAFFEA, continued: We would like to see the industry continuously reveal their industry-wide data to completely explain the "reusing and recycling on average more than 60 percent of its water" quote. Here are some problems with it:

It is possible that over the last few months of development in Pennsylvania a significant amount of flowback fluid recycling is happening. However, here are direct quotes from the industry that clearly indicate that this is a very recent development:

From the AP, Sunday, February 7, 2010: With fortunes, water quality and cheap energy hanging in the balance, exploration companies, scientists and entrepreneurs are scrambling for an economical way to recycle the wastewater. "Everybody and his brother is trying to come up with the 11 herbs and spices," said Nicholas DeMarco, executive director of the West Virginia Oil and Natural Gas Association. "

From the Houston Chronicle, Fri 12/11/2009: "...The industry is also trying to find ways to recycle the water used in fracturing in order to reduce the effect on local water supplies. "We're still in the infancy of trying to figure out how to recycle the water," said Ron Hyden, the manager for

Halliburton's production enhancement business. "We're trying to be good corporate citizens on that front."

From the ***Chesapeake*** *website: Recycling Technology: Why can't the water generated from natural gas production be recycled?*

Most of the water generated from natural gas production contains too many naturally occurring minerals, such as salt, to be recycled effectively. There has been some success in recycling the first 5% of produced water during flowback operations. However, by the end of the first few days after fracing (and in some cases a few hours), salt content of the produced water can reach as high as 70,000 parts per million (ppm), more than twice the salinity of seawater (30,000 ppm). The majority (95%) of the produced water returned from the well, with its high salt content, is too saturated to make recycling currently economically viable. Chesapeake and others in the industry are constantly evaluating opportunities to treat produced water, so that less of it will need to be injected into saltwater disposal wells."

WESTON WILSON Defends Himself

GG. E-I-D: Weston Wilson (EPA "whistleblower"): "One can characterize this entire [natural gas] industry as having a hundred year history of purchasing those they contaminate." (33:36)

- Mr. Wilson, currently on staff at EPA's Denver office, was not part of the team of scientists and engineers that spent nearly five years studying hydraulic fracturing for EPA. That effort, released in the form of a landmark 2004 study by the agency, found "no evidence" to suggest any relationship between hydraulic fracturing and the contamination of drinking water.
- Wilson has a well-documented history of aggressive opposition to responsible resource and mineral development. Over his 35-year career, Mr. Wilson has invoked "whistleblower" status to fight dam construction in Colorado, oil and gas development in Montana, and the mining of gold in Wyoming.
- Wilson in his own words: "The American public would be shocked if they knew we make six figures and we basically sit around and do nothing."

WESTON WILSON: The first part, that I was not part of the EPA team working on the HF in coal report issued June 2004, is correct—see my Oct 2004 report to Congress where I stated: "I was not *involved in either the preparation or review of EPA's report on the hydraulic fracturing of coal bed methane reservoirs."*

EPA's June 2004 report did establish—as I said in my whistleblower response to that report delivered to Congress, that: "EPA has established that: 1) coal bed methane hydraulic fracturing occurs within underground sources of drinking water, 2) hydraulic fracturing fluids contain toxic components that are not entirely removed during methane gas production, and 3) this fracturing process can create pathways which allow methane to migrate into high quality ground water."

There was a pivotal press article at that time by Tom Hamburger of the Los Angeles Times: "Halliburton's Interests Assisted by White House": The administration has lent support to a lucrative drilling technique. Some in the EPA consider it an environmental concern." See http://www.commondreams.org/headlines04/1014-07.htm or http://articles.latimes.com/2004/oct/14/nation/na-frac14 Incidentally, this White House influence done then in early 2000 on fracking, is under some intense scrutiny again related to how Cheney apparently obtained limits on the use of blowout preventers and the BP Gulf disaster.

Here's another source for history from the Western Organization of Resource Councils on the LEAF case and EPA IG 2005 investigation: http://www.worc.org/userfiles/file/EPAFracStudyFactSheet.OA.pdf Here's the Waxman 2005 letter to EPA IG Nikki Tinsley: http://waxman.house.gov/UploadedFiles/Letter_to_EPA_IG.pdf The part I particularly appreciate is this: "The concerns expressed by Weston Wilson find substantiation in the body of the (EPA) report."

*Here is a copy of my talking points I used to respond to the press in late 2004. This deals with my professional expertise, experience at EPA, and why I objected to Congress about EPA's shortcomings in that 2004 report on coal bed fracking. *Talking Points, Oct 19, 2004, prepared by Wes Wilson Who I am — I am an environmental engineer with 30 years experience at EPA. Since 1972 the Clean Air Act has required that EPA conduct independent reviews of other federal agencies' environmental impact statements. That's what I do. I review the environmental impacts of oil and gas development on the nation's public lands – lands managed by the Bureau of Land Management or the National Forest Service.*

What I did — I objected to EPA's conclusion that injecting toxic fluids, fluids that are carcinogenic, into underground sources of drinking water poses little or no threat to drinking water and need not be studied any further. I objected because this practice is improper under the Safe Drinking Water Act, egregiously improper in my view. On October 8th, I sent an 18-page report to my congressional delegation requesting they investigate EPA's failures to protect underground sources of drinking water. Why I did it — I have 3 reasons for blowing the whistle.

1. *EPA did not follow its own science policy, which required EPA to obtain water quality data in each coal basin where hydraulic fracturing is occurring.*
   a. *EPA found that toxic and carcinogenic fluids were injected into the ground where the water is used, or could be used, to supply drinking water, and found that some but not all of these fluids would be pumped out and simply assumed that the remainder would be diluted to some unspecified degree.*
   b. *EPA's own science-based Quality Assurance Plan, EPA's scientific basis for this study, specified EPA would obtain data in each coal basin if it found toxic fluids were injected.* [1]
   c. *EPA has no data on the amount of toxic fluids are injected, what remains in the ground, whether the water will still be usable for drinking, and what the health risks are.*
   d. *Yet EPA reached the unsupportable and scientifically unsound conclusion that hydraulic fracturing poses little or no threat to drinking water sources.*
2. *EPA's decision is inconsistent with the purposes of the law.*
   a. *The Safe Drinking Water Act requires EPA to protect drinking water sources. 80% of Americans rely of water from wells for fresh drinking water. EPA does this with a program called the Underground Injection Program, and although a federal court ordered EPA to regulate the injection of fluids for hydraulic fracturing, EPA has done this only in Alabama where the case began.*
   b. *Prior to the court ruling, way back in 1996, EPA had the view that the primary purpose of these wells was to produce natural gas, and EPA claimed it should not regulate gas production wells. The court ruled EPA's view was "inconsistent with the plain language of the law — the Safe Drinking Water Act."* [2] *The court found that hydraulic fracturing wells fit squarely within a certain class of well which must be regulated.*
   c. *So all states should be regulating this practice* [3]*, but they are not.*
   d. *EPA's only response was to obtain a voluntary agreement* [4] *with 3 oil service companies. These 3 companies voluntarily agreed not to inject diesel fuel, a very toxic part of the*

injection fluids because diesel fuel contains benzene which is carcinogenic in drinking water at just 5 parts per billion. But this agreement does not apply to:

- *any other company doing the same thing*
- *any other toxic or carcinogenic chemical in the fluids. And, since the fluids are considered "proprietary," the public does not know what else may be in these hydraulic fracturing fluids.*

3. *EPA relied on an expert Peer Review Panel whose members had potential conflicts of interest.*
   a. *Once again, EPA did not follow its own science policy.*
   b. *EPA's policy is that peer reviewers should be free of real or perceived conflicts-of-interest and there should be a balancing of interests among peer reviewers. Obtaining a fair and credible peer review is essential to maintaining the credibility and scientific validity at EPA.[5]*
   c. *Yet most of EPA's 7-member expert peer review panel appear to have conflicts of interest:*
      - *An engineer at Halliburton,*
      - *A manager of an industry-funded group that previously worked for Halliburton,*
      - *An engineer at BP Amoco,*
      - *Two academics who had worked for the industry,*
      - *A state regulator who also worked for Amoco.*
      - *The 7th panel member is from DOE's Sandia National Labs.*
   d. *It's a hand-picked, conflicted small group, who failed to even read the final report and met only once.*
   e. *This is not peer review — this is a mockery of what is supposed to be an independent and balanced review. This is the thin veneer cover to a scientifically unsound study while the scientific process of Peer Review was abandoned.*

***End of these talking points.*

[1] Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA, June 2004, Appendix B, Quality Assurance Plan, page App. B-5.

[2] Legal Environmental Assistance Foundation vs. United States Environmental Protection Agency, United States Court of Appeals for the Eleventh Circuit, No. 00-10381, EPA No. 65-02889-Fed. Reg., December 21, 2001. http://www.epa.gov/safewater/uic/leaf2.pdf

[3] Letter to EPA Administrator Michael Leavitt from Senators Jeffords and Boxer, October 14, 2004.

[4] Memorandum of Agreement Between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc. and Schlumberger Technology Corporations, Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells, signed bG. Tracy Mehan, III; EPA Office of Water and representatives of the above companies,

[5] Science Policy Handbook, Office of Science Policy, U.S. Environmental Protection Agency, Office of Research and Development, December 2000, EPA 100-B-00-001, Sections 3.4.5-6. *http://epa.gov/osa/spc/htm/prhandbk.pdf*

More on DUNKARD CREEK

BARBARA ARRINDELL: Golden algae do not grow and flourish in fresh water, only in saline (salty) water environments. Dunkard Creek went from fresh to salt from Marcellus gas well waste being dumped into coal mine voids. Legal or illegal, this is what changed Dunkard Creek to a saline environment.

STEVE COFFMAN: The following article was written by environmental reporter Don Hopey of Pittsburgh Post-Gazette (Sunday, September 20, 2009):

Sudden Death of Ecosystem Ravages Long Creek. 'Everything is being killed': 161 aquatic species have died along Dunkard Creek

An early and continuing focus of the investigation has been discharges from a mine water treatment facility located at Consol Energy's Blacksville No. 2 mine in West Virginia.

But state and federal investigators are confounded because chemical analysis shows the creek water at the treatment facility site contains extremely high total dissolved solids, or TDS, and chlorides—properties found in wastewater from Marcellus Shale gas well drilling operations but not mine water. Total dissolved solids may include metals, salts and other elements.

Marcellus Shale well drilling water contains about 100 chemicals added to reduce friction, eliminate algae growth and perform other functions when water is pumped underground under pressure to fracture the shale and release natural gas.

Up to 4 million gallons are used for each Marcellus Shale well. Disposal of wastewater from the wells has caused problems throughout Pennsylvania, including TDS readings that exceeded federal safe drinking water standards in the Monongahela River last winter and this year.

On Thursday, investigators found dead fish for the first time about a mile and a half up the creek above the treatment plant discharge.

"Our hypothesis was that it's coming out of the Blacksville No. 2 mine, but the finding of dead fish upstream from the Blacksville discharge indicates the sole cause cannot be Blacksville," said West Virginia DEP spokeswoman Kathy Cosco. [end]

More on METHANE MIGRATION/FLAMMABLE WATER

WESTON WILSON:
I talked to an oil industry insider who doesn't want to be named. He told me a plausible explanation of how the methane in Mike Markham's well and the other domestic wells in Weld County could be the result of drilling. As a geologist I believe this theory is relevant and in need of testing by the state:

Drilling in this geologic basin, the Denver-Julesburg Basin, requires drilling through coals that contain some gas. Since those shallow coals have bacterial decay, the biogenic gas is there—biogenic gas is what the Colorado Oil and Gas Conservation Commission inspector found in Markham's well. The biogenic gas in these near-surface coals will remain there as long as there is groundwater on top of it to hold it in place.

This near-surface gas in these coals is not what the companies are drilling for — they are drilling deeper in the basin for economically recoverable gas deposits. However, when the industry takes out massive amounts of water for drilling and fracking purposes, they obtain that water from the upper aquifer that includes the coals. This causes the water table to drop and release the biogenic gas in those coals. If there is a domestic well nearby, then it can show up at the tap and be burned.

The groundwater drawdown in this geologic basin is also due to water pumped for irrigation, so this might be a combination of too much ground water pumping by both oil/gas drilling and irrigation, *but the point is that it is a plausible cause and effect relationship to prior drilling. This fits the basic pattern that gas in people's wells comes AFTER drilling.*

If this is accurate, then the COGCC would have been in error concluding that the gas in Markham's well was not due to drilling, but keep in mind the COGCC is using the phrase "not due to oil and gas activities" based only on the point that such gas is not DIRECTLY due to a driller's mistake. In this case, if this theory holds, it could be due to the combined impacts of groundwater drawdown from the combination of both drilling in the RED zone and irrigation drawdown.

More on DISH and TCEQ

Original DISH air tests quoted in the film: http://www.townofdish.com/objects/DISH_emergency_res_report_pdf.pdf

Texas state agencies have a history of obfuscation on gas issues. TCEQ's spin is similar to the DSHS spin: Read the Texas Observer's startling exposé on the Texas Commission on Environmental Quality:

Agency of Destruction

Texas' environmental commission serves its customers well. Too bad they're not the public.

Last September, the tiny town of DISH—frustrated by the lack of action on TCEQ's part— announced the results of a bombshell air-quality study it spent 10 percent of the town's annual budget to commission from outside experts. Air samples from residential areas near gas-compressor stations contained high levels of benzene, and other carcinogens and neurotoxins—much higher than TCEQ health-based standards. Evidence in hand, DISH Mayor Calvin Tillman, a conservative who's become the bane of North Texas gas interests, called on the industry to clean up its act or get out of town.

The fallout from the DISH study prompted TCEQ to do its own testing during three days in December. On Jan. 12, Deputy Director John Sadlier presented the much-anticipated results to the Fort Worth City Council.

"Everything you hear today will be good news," Sadlier told the packed council meeting. The commission staff, he said, had visited 126 sites in the Fort Worth area and found no evidence of benzene or other cancer-causing chemicals. "Based on this study, the air is safe," Sadlier told the council.

Later, Mayor Mike Moncrief, who comes from a prominent oil and gas family, pronounced himself "grateful" for the results. Since that burst of good news, Fort Worth city officials, including Moncrief, have generally resisted calls to impose more stringent rules on gas drilling. "Sadlier's comments only emboldened the council's belief that the air quality is okay," wrote Don Young, a drilling reform activist in Fort Worth.

If council members had squinted, they would have seen a disclaimer stamped at the bottom of each page of Sadlier's PowerPoint presentation: "This data is for screening purposes only and may include samples that did not meet the established quality control acceptance criteria," the disclaimer read.

As drilling activists discovered, the state's study was rubbish. The testing was done on cold days, when benzene tends to be inactive. The inspectors took samples only if the levels measured 140 times the Metroplex average—far above state health standards. Only eight samples were collected.

Confronted with these facts, commission PR staffers stuck with the original message. "We were trying to do that really fast," TCEQ spokesperson Terry Clawson told the Fort Worth Weekly. "If you are going to do testing and use certified labs and have it legal quality, that takes a long time."

TCEQ used those results to "prove" that benzene wasn't a problem. And an internal investigation prompted by an anonymous fraud complaint revealed that upper managment, including Sadlier and Executive Director Mark Vickery, knew the study was flawed. In fact, they ordered that the eight canister samples "be analyzed using a more sensitive laboratory technique." The results came back on Jan. 22, 10 days after Sadlier's rosy depiction at the Fort Worth meeting. Four of the eight samples measured benzene at levels above what the state considers safe for long-term health. Still, the fraud investigation states, Sadlier was "not confident in accuracy [sic] of the results from the field" or the fresh lab findings, and ordered inspectors to return to Fort Worth for more samples. article: http://www.texasobserver.org/cover-story/agency-of-destruction

2.6 Hydraulic Fracturing FAQs

The Gasland webpage presents the following frequently asked questions and answers on hydraulic fracturing. http://one.gaslandthemovie.com/whats-fracking#faq

2.6.1 Is fracking safe?

No, fracking, as currently practiced across the United States, poses serious risks to the health and safety of communities and the environment.

Water supplies across the country have been contaminated in fracking-related cases -- either by natural gas that migrates out of wells and into underground aquifers, or by any number of byproducts from of fracking process: chemicals, harmful and/or toxic substances from the underground rock such as naturally occurring radioactive materials (NORMs), dissolved solids, liquid hydrocarbons including benzene, toluene, ethylbenzene, and xylene, and heavy metals.

2.6.2 How serious is water contamination due to fracking?

Very serious. For one thing, we don't even know all the chemicals being used for fracking. But many of the ones we do know about are well-documented (1,2,3) for causing cancer, birth defects, and disorders of the nervous system. The same is true of many naturally occuring but highly toxic substances that are unearthed in the process, then seap into the water supply.

2.6.3 What do you mean you don't know all the chemicals being used for fracking? Haven't you done your research?

Oh, we've done our research, alright. The reason many fracking chemicals go unknown is they're never actually disclosed at all, anywhere, to anyone, ever.

Fracking was explicitly made exempt from the Safe Water Drinking Act by a piece of energy legislation passed by Congress called the Energy Policy Act of 2005. This exemption allows drilling and fracking companies to inject unknown and/or toxic materials directly into, below, or adjacent to underground sources of drinking water without reporting the chemicals or the quantities of these chemicals to the government or to the public.

2.6.4 What are the environmental considerations of fracking?

While there are serious public health risks posed by fracking, there are major impacts on the climate, too. Methane, the same thing as natural gas, is a potent heat-trapping gas, up to 105 times more powerful than carbon dioxide upon release over a 20-year interval. Methane leaks at every stage of a fracking operation, from production and processing to transmission and distribution. The much-touted 50% reduction in climate impact from burning gas is not likely to be achieved for many decades -- if ever -- due to leaking. And we don't have many decades to stabilize the climate.

2.6.5 Don't we have the technology to make fracking safe?

Nope, no technology currently exists to make fracking safe. Here are some of the numbers from reports released by drilling giants Schlumberger, Archer Oil & Gas, Southwestern Energy, and the Society of Petroleum Engineers:

- Around 5% of oil and gas wells leak immediately and up to 60% of them fail over a 30-year time period,according to multiple studies.
- About 35% of all oil and gas wells are leaking now.

These industry reports support similar findings from state agencies, like the Pennsylvania Department of Environmental Protection and the Colorado Oil and Gas Conservation Commission.

Some recent modifications to cementing regulations misguidedly include requirements on cement strength. But it is not a question of stronger cement or better technology. Industry's own documents say that:

> "strength is not the major issue in oil well cementing under any circumstances … cement clearly cannot resist the shear that is the most common reason for oil well distortion and rupture during active production."

In other words, the high stresses and rock movements deep underground will cause a significant proportion of wells to fail no matter what.

2.6.6 How deep do natural gas wells go?

The average well is up to 8,000 feet deep. The depth of drinking water aquifers is about 1,000 feet. The problems typically stem from poor cement well casings that leak natural gas as well as fracking fluid into water wells.

2.6.7 Why do so many wells leak?

Pressures under the earth, temperature changes, ground movement from constructing nearby wells, and shrinkage crack and damage the thin layer of brittle cement that seals the wells. And getting the cement right as drilling goes horizontal is extremely challenging. Meanwhile, once the cement leaks, attempting to repair it thousands of feet underground is expensive and often unsuccessful. Even if successfully repaired, methane migration might have been occurring for months or years.

Some recent modifications to cementing regulations misguidedly include requirements on cement strength. But it is not a question of stronger cement or better technology. Industry's own documents say that:

> "strength is not the major issue in oil well cementing under any circumstances … cement clearly cannot resist the shear that is the most common reason for oil well distortion and rupture during active production."

In other words, the high stresses and rock movements deep underground will cause a significant proportion of wells to fail no matter what.

Other industry documents show that well failure is a widespread problem around the world, that abandoned wells are a major migration pathway to aquifers, and that there are multiple scenarios by which gas and other contaminants can escape a well to contaminate water supplies.

Industry also asserts that the gas reservoirs they target are thousands of feet deeper than water supply aquifers. Therefore, industry says, there is no way the water supply could have been contaminated by their operations. But the cement barrier around the wells can fail from many causes, or be absent, allowing gas to migrate out of the well and into the drinking supply.

2.6.8 Are the flaming faucets from Dimock, PA fake?

Not only are the flaming faucets from Dimock real, but contamination has been conclusively traced to the fracking-related activity of one particular company.

The Pennsylvania Department of Environmental Protection's (DEP) investigation revealed that the methane contamination was due to gas drilling, specifically finding that 18 drinking-water wells in the area were affected by the operations of Cabot Oil & Gas (1, 2).

Further tests of Dimock water by U.S. Environmental Protection Agency also clearly showed contaminants tracable to Cabot's fracking activities.

Industy arguments that methane occurs naturally in the environment in the Dimock area and therefore should be expected in the water suplly are dangerously misleading. A Duke University study found that drilling into the methane layer allows the natural but toxic gas to migrate into the water supply.

2.6.9 Haven't there been flaming faucets for years because methane is a naturally occurring gas?

The flaming faucets documented in Gasland are the product of natural gas migration into water supplies in most cases due to fracking right next door. Numerous investigations have confirmed this fact, including studies by the United States Environmental Protection Agency, the Pennsylvania Department of Environmental Protection, and many others. Industry is essentially claiming a giant conspiracy theory - that these families all across the country are lying in reporting that their wells never flamed before fracking.

Further, methane and natural gas are the same thing. So when industry claims methane in drinking water supplies is "naturally occurring" it's just another smokescreen. Industry also tries to defend itself by asserting that the gas found in water supplies sometimes has a different chemical fingerprint than the gas they are going after. They distinguish between biogenic gas - found closer to the surface - and thermogenic gas - found much deeper underground. Industry is after thermogenic gas because it's been "cooked" longer and therefore has a higher energy density. But industry's drilling pierces different gas layers and allows them to mix. Failure or absence of the cement well seal allows gas from any layer to migrate into the water supply.

Additionally, Duke University recently conducted a peer-reviewed study that links water contamination with nearby drilling and fracking, concluding that water wells near drilling and fracking operations were seventeen times more likely to contain elevated levels of methane.

2.6.10 Do you agree natural gas from fracking is a bridge fuel while we develop carbon-free sources of energy like wind and solar?

Fracked gas is a bridge to nowhere. Reports (1, 2) suggest fugitive emissions of methane are so substantial that they completely outweigh any climate benefits of gas as compared to coal. Further, the flood of cheap natural gas in the market is having unintended consequences for renewable energy, which is being further squeezed out of the market place.

Gas is already displacing renewable energy. The costs of wind and solar are coming down all the time but they are battling for parity with fossil fuels on an asymmetric playing field. Until fossil fuels have prices that reflect their true costs to society - via a carbon tax, for example - renewables will continue to face stiff odds. The glut of cheap gas is only making these odds stiffer.

2.6.11 Isn't gas better for the environment than coal?

The leakage of methane - a potent heat-trapping gas - likely outweighs much, if not all of the climate benefit of natural gas versus coal. When burned in a power plant, natural gas gives off about 50 percent of the carbon dioxide emissions as coal. But this ignores the widespread problem of leaking methane. Methane's warming potential far exceeds that of carbon dioxide: On a twenty year time scale, methane traps heat up to 105 times more effectively than an equal mass of CO_2. Unburned methane is a byproduct at every stage of the gas development lifecycle, including production, processing, transmission, and distribution.

Multiple studies (1, 2) suggest that "fugitive emissions" of methane from wells and pipelines are significant, thereby offsetting the climate benefits of gas versus coal.

Indeed, gas produced from fracked wells may actually turn out to be worse than coal: Once fugitive methane emissions exceed 2-3 percent of total gas production, natural gas's climate advantage over coal disappears over a 20-year time horizon. Recent studies (1, 2) suggest leakage rates well above this threshold.

In addition, shale gas represents one of the largest reserves of carbon on earth. If we burn more than a tiny fraction of it, putting its carbon into the atmosphere, it will be impossible to keep global temperatures from rising beyond a livable threshold.

2.6.12 Won't fracking bring us energy independence?

No. The idea that fracking is the key to American energy independence is a myth. We don't use natural gas to power cars, and we don't use oil to generate electricity.

Also, much of the gas fracked in the U.S. might end up overseas. This reality is dictated by basic economics: gas will flow to the highest bidder. Currently, gas in Europe costs about 3 times more per unit than it does in the U.S. Prices in Asia are even higher. These realities are leading to an explosion of permitting requests for the construction of Liquefied Natural Gas (LNG) terminals on our coasts for the purpose of transporting gas overseas.

Once gas starts to flow overseas, moreover, it is only a matter of time before gas prices rise in the U.S. Eventually gas prices will be dictated by the world market - like oil - and no amount of domestic gas supply will be able to influence this reality. (Meanwhile the energy it takes to liquefy natural gas, and the additional leakage of methane during processing and transport of LNG, further erode any possible climate advantage).

2.6.13 What about the jobs created by fracking?

The jobs created by fracking are not the kind of quality jobs American workers deserve. They are dangerous, exposing workers to chemicals whose long-term impacts on human health are yet unknown. And there just aren't that many jobs to be had, especially when compared to the plentiful and sustainable jobs available in the renewable power and energy efficiency sectors.

Consider these statistics:

- Job creation in energy efficiency is 2.5 times to four times - for building retrofits and mass transit, respectively - larger than that for oil and natural gas.
- For renewable energy, the job creation ranges between 2.5 times (wind) to three times (3) more than that for oil and gas.

In contrast:

- According to a recent New York Times article, jobs in the oil and gas industry are seven times more likely to be fatal than the U.S. average.

Josh Fox is currently conducting an investigation into worker safety and chemical risk. He has interviewed many workers who have been asked to clean drill sites, transport radioactive and carcinogenic chemicals, steam clean the inside of condensate tanks which contain harmful volatile organic compounds (VOCs), polycyclic aromatic hydrocarbons (PAHs), and other chemicals and have been told to do so with no safety equipment. Many workers have been harmed and made ill to the point to which they can no longer function normally and have been fired or quit without health insurance.

A bill to address worker safety, drafted by State Senator Tony Avella of New York, dubbed "CJ's Law" in honor of CJ Bevins, a rig worker killed by an unsafe site in New York State, currently has more than 30 co-sponsors and is moving through the NY State Senate.

2.6.14 Won't regulations force fracking be done safely?

Fracking is exempt or excluded from most major federal laws protecting environmental health. In the absence of federal oversight, states are empowered to regulate fracking. However, the current state-by-state patchwork of rules and regulations gives little cause for comfort.

Fracking was formally exempted from the Safe Water Drinking Act by the Bush Administration in 2005 via the so-called Halliburton loophole - named after the company formerly led by Vice President Cheney that called for the exemption during Cheney's secret Energy Task Force meetings. Mirror exemptions exist under a host of other major federal regulations, including the Clean Water Act, the Clean Air Act, the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response Conservation and Recovery Act (CERCLA), the National Environmental Protection Act (NEPA), the Superfund law, and the Toxic Release Inventory under the Emergency Planning and Community Right to Know Act (EPCRA).

2.6.15 Isn't the Obama administration issuing new rules on fracking?

The new rules *only* apply to fracking on federal land, which is only a tiny slice of fracking nationwide. These rules are inadequate to protect federal lands and are currently being weakened by tremendous industry pressure. As stated above, there are no regulations which can make fracking safe, either on federal or private lands.

The Department of Interior announced proposed new rules to regulate fracking on federal lands. However, the vast majority of fracking in the United States takes place on private lands. Regulation of fracking thus almost completely falls to the states. But state regulations have hardly been able to keep up with the recent explosion of fracking activity, and the laws and rules on the books vary widely in stringency and enforcement. Studies have also documented how industry "captures" local governments.

There is also a considerable lack of transparency among companies involved in fracking, which is aided and abetted by state and federal regulators. For instance, while states like Texas, Wyoming and Pennsylvania require "disclosure" of the chemicals used in a fracking operation, the requirement is gutted by "trade secret" exemptions, which shield companies from disclosing their toxic recipes. The federal government also memorializes the trade secret exemption in its new proposed rules, which, again, are only applicable to federal lands. The federal rules include another major giveaway to industry, in that they would only require disclosure of the "disclosable" chemicals (i.e., those not falling under the trade secret exemption) *after* the fracking operation is completed. That leaves concerned citizens and watchdog groups powerless to monitor possible contamination of drinking water supplies in real time.

2.6.16 What about the University of Texas study that finds no connection between fracking and water contamination?

The University of Texas at Austin has withdrawn that study after an investigation revealed that the lead investigator, Charles "Chip" Groat, has financial interests in the natural gas industry, which he did not disclose in his report.(fn)Bloomberg News reported July 23, 2012 that Groat has been on the board of Plains Exploration & Production Co. (PXP) since 2007. As a board member, Groat receives 10,000 shares of restricted stock a year, as well as an annual fee, which was $58,500 in 2011 - according to company filings. Groat has since retired from his UT faculty position; Raymond Orbach, director of the Energy Institute at UT, which conducted the study, has resigned as well.3

2.6.17 What's in fracking fluid?

Fracking fluid is a toxic brew that consists of multiple chemicals. Industry can pick from a menu of up to 600 different kinds. Typically, 5 to 10 chemicals are used in a single frack job, but a well can be fracked multiple times, and each gas play consists of tens to hundreds of thousands of wells - driving up the number of chemicals ultimately used. Many fracking chemicals are protected from disclosure under trade secret exemptions. Studies of fracking waste have identified formaldehyde, acetic acids, and boric acids, among hundreds of others.

For each frack, 80-300 tons of chemicals may be used, selected from a menu of up to 600 *different* chemicals. Though the composition of most fracking chemicals remains protected from disclosure through various "trade secret" exemptions under state or federal law, scientists analyzing fracked fluid have identified volatile organic compounds (VOCs) such as benzene, toluene, ethylbenzene and xylene - all of which pose significant dangers to human health and welfare.

Industry says it's misleading to suggest 600+ chemicals are used in a fracking operation since only a small percentage of this number of chemicals is used per well. But this "one-well" model is the biggest misrepresentation of all: fracking operations in a gas play typically consist of many thousands of wells. Cumulative impacts are what matter.

2.6.18 How much water is used during fracking operations?

Generally, 2-8 million gallons of water may be used to frack a well. Some wells consume much more. A well may be fracked multiple times, with each frack increasing the chances of chemical leakage into the soil and local water sources.

The sheer volume of water brought to and from the fracking site means a glut of tanker trucks through your town. The New York State Department of Environmental Conservation estimates each well, per frack, will require 2.4 to 7.8 million gallons of water. This translates into roughly 400 to 600 tanker truckloads of liquids to the well, and 200 to 300 tanker truckloads of liquid waste from the well. An eighteen-wheeler weighs up to 80,000 lbs. Day-in, day-out, these trucks destroy roads and bridges, leaving towns to clean up the mess.

Further, the one-well model is not an accurate representation of fracking operations, which can consist of 20 wells per "pad" and dozens of pads: Overall, 38,400 to 172,800 tanker truck trips are possible over a well pad life.

2.6.19 What happens to wastewater

Wastewater disposal is among the biggest challenges of fracking. Although up to 85 percent of fracking fluid remains underground, the wastewater that does return to the surface (also called "flowback water" or "produced water" or "brine") is contaminated and must be treated and disposed of. This liquid waste is frequently stored temporarily in open pits, or "misted" into the atmosphere. There are several options for permanent disposal of wastewater: (1) trucking to an industrial wastewater treatment facility; (2) trucking to injection wells deep underground; (3) reuse by recycling into another frack job. Each option has multiple environmental risks.

2.6.20 Can fracking cause earthquakes?

Fracking has been proven to cause earthquakes, directly and indirectly. The National Research Council settled the debate about indirect cause with a comprehensive study in 2012. The study concluded that the greatest risk of earthquakes does not come from drilling or fracking but from pumping the wastewater from fracking into deep rock reservoirs. Such wastewater injection was blamed for earthquakes that occurred in Youngstown, Ohio, on Christmas Eve and on New Year's Eve 2012, measuring 2.7 and 4.0 on the Richter scale, respectively. The British Columbia Oil and Gas Commission concluded that fracking itself directly caused seismicity in the Horn River shale play, and that those earthquakes damaged underground well structures.

2.6.21 Does fracking cause air pollution?

Before the wastewater is trucked to a remote injection well or processing facility for disposal, wastewater ponds and condensate tanks release volatile organic compounds (VOCs) 24 hours a day, seven days a week. As the VOCs are evaporated and come into contact with diesel exhaust from trucks and generators at the well site, ground level ozone is produced. Ozone plumes can travel up to 250 miles. This is apart and distinct from the carbon pollution issue, by which methane and CO_2 from the gas production and combustion process contribute to global warming.

2.6.22 What is horizontal hydraulic fracturing?

Horizontal hydrofracking is a means of tapping shale deposits containing natural gas that were previously inaccessible by conventional drilling. Vertical hydrofracking is used to extend the life of an existing well once its productivity starts to run out, sort of a last resort. Horizontal fracking differs in that it uses a mixture of 596 chemicals, many of them proprietary, and millions of gallons of water per frack. This water then becomes contaminated and must be cleaned and disposed of.

2.6.23 How does hydraulic fracturing work?

Hydraulic fracturing or fracking is a means of natural gas extraction employed in deep natural gas well drilling. Once a well is drilled, millions of gallons of water, sand and proprietary chemicals are injected, under high pressure, into a well. The pressure fractures the shale and props open fissures that enable natural gas to flow more freely out of the well.

2.6.24 What is the Halliburton Loophole?

In 2005, the Bush/ Cheney Energy Bill exempted natural gas drilling from the Safe Drinking Water Act. It exempts companies from disclosing the chemicals used during hydraulic fracturing. Essentially, the provision took the Environmental Protection Agency (EPA) off the job. It is now commonly referred to as the Halliburton Loophole.

2.6.25 What is the FRAC Act?

The FRAC Act (Fracturing Responsibility and Awareness to Chemical Act) is a House bill intended to repeal the Halliburton Loophole and to require the natural gas industry to disclose the chemicals they use.

3.0 Gasland 2 – Movie

3.1 About the Movie

In this explosive follow-up to his Oscar®-nominated film GASLAND, filmmaker Josh Fox uses his trademark dark humor to take a deeper, broader look at the dangers of hydraulic fracturing, or fracking, the controversial method of extracting natural gas and oil, now occurring on a global level (in 32 countries worldwide).

GASLAND PART II, which premiered at the 2013 Tribeca Film Festival, shows how the stakes have been raised on all sides in one of the most important environmental issues facing our nation today. The film argues that the gas industry's portrayal of natural gas as a clean and safe alternative to oil is a myth and that fracked wells inevitably leak over time, contaminating water and air, hurting families, and endangering the earth's climate with the potent greenhouse gas, methane. In addition the film looks at how the powerful oil and gas industries are in Fox's words "contaminating our democracy".

3.2 Reviews

- "Josh Fox does it again in a brilliant GASLAND sequel" –Alison Rose Levy, Alternet
- "Gasland Part II shows how much higher the stakes have grown in the battle over fracking since Josh Fox made its predecessor." – Grist
- "Haunting and Provocative" – LA Times
- "A must watch for all the environmentally conscious" –Examiner
- "The movie builds on Fox's Academy Award-nominated "Gasland," further making the case of how the shale industry's hydraulic fracturing ("fracking") boom is busting up peoples' livelihoods, contaminating air and water, polluting democracy and serving as a "bridge fuel" only to propel us off the climate disruption cliff." – DeSmogBlog

3.3 The Team

Josh Fox is the Founder and Producing Artistic Director of the International WOW Company. Josh has written/directed/produced three feature films, several short films and over twenty-five full- length works for the stage which have premiered in New York, Asia and Europe. GASLAND, which Josh wrote, directed and shot, premiered at the Sundance film festival 2010, where it was awarded the 2010 Special Jury Prize for Documentary. The film was nominated for the Academy Award for best documentary, nominated for four Emmys including best documentary, best writing and best cinematography, and awarded the EMMY for best directing. GASLAND was nominated for best Documentary Screenplay by the WGA, and also awarded the Environmental Media Association Award for best documentary. As a result of Josh's activism and campaigning on the issue of gas drilling Josh was awarded the 2010 Lennon Ono Grant for Peace by Yoko Ono.

Trish Adlesic – Producer, is an Oscar and Emmy nominated documentary Producer. She produced Josh Fox's GASLAND for HBO and just finished post-production on GASLAND Part II, also for HBO. A seasoned filmmaker, Adlesic has spent the past twenty-two years on multiple television and feature film productions. She began her career on the pilot for the hit television show Law and Order. She has continued to hone her craft working on feature films and on the hit television show Law & Order: Special Victims Unit. Throughout her career, Adlesic has worked with esteemed directors such as: Robert Benton, Sidney Lumet, Michael Mann, James L. Brooks, Gus Van Sant, and Jim Sheridan. She has been a member of the Director's Guild of America for fifteen years, serves on the Eastern AD/UPM council, and has been a national delegate.

Matthew Sanchez – Editor, has primarily focused his involvement in filmmaking as a documentary cameraman. For 6 years, he worked as an editor and cinematographer at a non-profit for environmental awareness, often bringing him to the Delaware watershed. While lensing over 25 short films, his varied work includes commercials for VH1, documenting the NYC underground music scene, Wired Magazine, and College Humor. Matt and Josh met at Cinevegas Film Festival, where his own film HAPPY BIRTHDAY HARRIS MALDEN premiered alongside Mr. Fox's debut feature, MEMORIAL DAY. He has also earned 4 Telly awards and cut a program for PBS that was nominated for 2 Emmy awards.

Deborah Wallace – Producer, is a Producer and Co-Artistic Director of the award-winning International WOW Company, founded in 1996 by Josh Fox and producers of the Academy Award nominated, Emmy winning documentary film, Gasland. With International WOW Company she has collaborated on the production of more than 20 works for the stage and screen. In the theater, Wallace has worked with some of the most lauded artists in America including Anne Bogart, SITI Company, John Zorn, Ann Hamilton and Richard Foreman. Also a director and playwright Wallace's work has been presented at HERE Arts Center, New Dance Group, The Ohio Theater and The Incubator Arts Project. For International WOW Company Wallace has produced the films The Sky Is Pink; Occupy Sandy; and Gasland, Part II for HBO.

Lee Ziesche - Grassroots Coordinator, studied broadcast journalism at the University of Florida, but fell in love with grassroots organizing as a Campus Leader for the ONE Campaign. Since then she's worked to connect schools and communities in Washington, D.C. as an AmeriCorps *VISTA Fellow, and to re-elect President Barack Obama as a Field Organizer for Obama for America in Western Pennsylvania. She has a B.S. in Telecommunications and a minor in International Humanitarian Assistance and Development

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Gas Drilling's Environmental Threat

September 2014

FRACKING – GAS DRILLING'S ENVIRONMENTAL THREAT

TABLE OF CONTENTS

NOTES

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    - http://www.propublica.org/
    - http://www.propublica.org/about/
    - http://www.propublica.org/series/fracking
    - http://www.propublica.org/special/hydraulic-fracturing-national
    - http://www.propublica.org/article/anatomy-of-a-gas-well-426
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FRACKING – GAS DRILLING'S ENVIRONMENTAL THREAT

1.0 About ProPublica

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Investigative journalism is at risk. Many news organizations have increasingly come to see it as a luxury. Today's investigative reporters lack resources: Time and budget constraints are curbing the ability of journalists not specifically designated "investigative" to do this kind of reporting in addition to their regular beats. New models are, therefore, necessary to carry forward some of the great work of journalism in the public interest that is such an integral part of self-government, and thus an important bulwark of our democracy.

ProPublica was founded by Paul Steiger, the former managing editor of The Wall Street Journal. It is now led by Stephen Engelberg, a former managing editor of The Oregonian, Portland, Oregon and former investigative editor of The New York Times, and Richard Tofel, the former assistant publisher of The Wall Street Journal.

ProPublica is headquartered in Manhattan. Its establishment was announced in October 2007. Operations commenced in January 2008, and publishing began in June 2008.

The Mission: To expose abuses of power and betrayals of the public trust by government, business, and other institutions, using the moral force of investigative journalism to spur reform through the sustained spotlighting of wrongdoing.

1.1 Why Now?

It is true that the number and variety of publishing platforms are exploding in the Internet age. But very few of these entities are engaged in original reporting. In short, we face a situation in which sources

of opinion are proliferating, but sources of facts on which those opinions are based are shrinking. The former phenomenon is almost certainly, on balance, a societal good; the latter is surely a problem.
More than any other journalistic form, investigative journalism can require a great deal of time and labor to do well—and because the "prospecting" necessary for such stories inevitably yields a substantial number of "dry holes," i.e. stories that seem promising at first, but ultimately prove either less interesting or important than first thought, or even simply untrue and thus unpublishable.

Given these realities, many news organizations have increasingly come to see investigative journalism as a luxury that can be put aside in tough economic times. Moreover, at many media institutions, time and budget constraints are curbing the once significant ability of journalists not specifically designated "investigative" to do this kind of reporting in addition to handling their regular beats.

1.2 What We Do

We have created an independent newsroom, located in Manhattan and led by some of the nation's most distinguished editors, and staffed at levels unprecedented for a non-profit organization.

In the best traditions of American journalism in the public service, we seek to stimulate positive change. We uncover unsavory practices in order to stimulate reform. We do this in an entirely non-partisan and non-ideological manner, adhering to the strictest standards of journalistic impartiality. We won't lobby. We won't ally with politicians or advocacy groups. We look hard at the critical functions of business and of government, the two biggest centers of power, in areas ranging from product safety to securities fraud, from flaws in our system of criminal justice to practices that undermine fair elections. But we also focus on such institutions as unions, universities, hospitals, foundations and on the media when they constitute the strong exploiting or oppressing the weak, or when they are abusing the public trust.

We address one of the occasional past failings of investigative journalism by being persistent, by shining a light on inappropriate practices, by holding them up to public opprobrium and by continuing to do so until change comes about. In short, we stay with issues so long as there is more to be told, or there are more people to reach.

We strive to be fair. We give people and institutions that our reporting casts in an unfavorable light an opportunity to respond and make sincere and serious efforts to provide that opportunity before we publish. We listen to the response and adjust our reporting when appropriate. We aggressively edit every story we plan to publish, to assure its accuracy and fairness. If errors of fact or interpretation occur, we correct them quickly and clearly. We aim for a working culture that embraces all of these principles, and insist that they infuse all that we do.

1.3 How We Do It

We have a newsroom of about 40 working journalists, all of them dedicated to investigative reporting on stories with significant potential for major impact.

Each story we publish is distributed in a manner designed to maximize its impact. Many of our "deep dive" stories are offered exclusively to a traditional news organization, free of charge, for publication or broadcast. We published more than 80 such stories in 2012 with more than 25 different partners. Many are augmented with data rich "news applications" which, in turn, permit the localization of stories on the same subject by other news organizations. Almost all our stories are available for reprint under a Creative Commons license. A series of our stories won the 2011 Pulitzer Prize for National Reporting, the first such prize ever for stories not published in print. One of our stories was awarded a Pulitzer Prize for Investigative Reporting in 2010, the first such award to an online news organization. Another story, broadcast in partnership with This American Life, won a Peabody Award in 2013. Every story is published on this site. The site also features outstanding investigative reporting produced by others, sometimes with our annotation and follow-up, thus making our site both more of a destination and a tool to promote more good work in this field.

We support each story we publish with an active and aggressive communications effort of our own, including regularly contacting reporters, editors and bloggers, encouraging them to follow-up on our reporting, and to link to our site and our work.

1.4 How It Is Funded

The Sandler Foundation made a major, multi-year commitment to fund ProPublica at launch. Other philanthropic contributions have been received as well, and more are needed. Click here to donate.

We spend more than 85 cents out of every dollar on news – almost the exact opposite of traditional print news organizations, even very good ones, that devote about 15 cents of each dollar spent to news. From a philanthropic perspective it is also worth noting that our model assures an unusually high level of accountability for a non-profit. Our major stories have to be sufficiently compelling to convince editors and producers to accord them space or time. As they do so consistently, donors will be able to be confident that professional standards are being met and maintained, and that important work is being undertaken. That said, our donors support the independence of our work, and do not influence our editorial processes.

ProPublica also accepts advertising. And we are constantly exploring possible new revenue streams, including ebooks, although philanthropy, in large gifts and small, will continue to be our principal source of income for the foreseeable future.

1.5 Governance

ProPublica is a non-profit corporation, and is exempt from taxes under Section 501(c)(3). It has its own Governing Board, of which Herbert Sandler is founding chairman and Mr. Steiger is executive chairman. A Journalism Advisory Board of leaders in the field, and a Business Advisory Council has also been assembled.

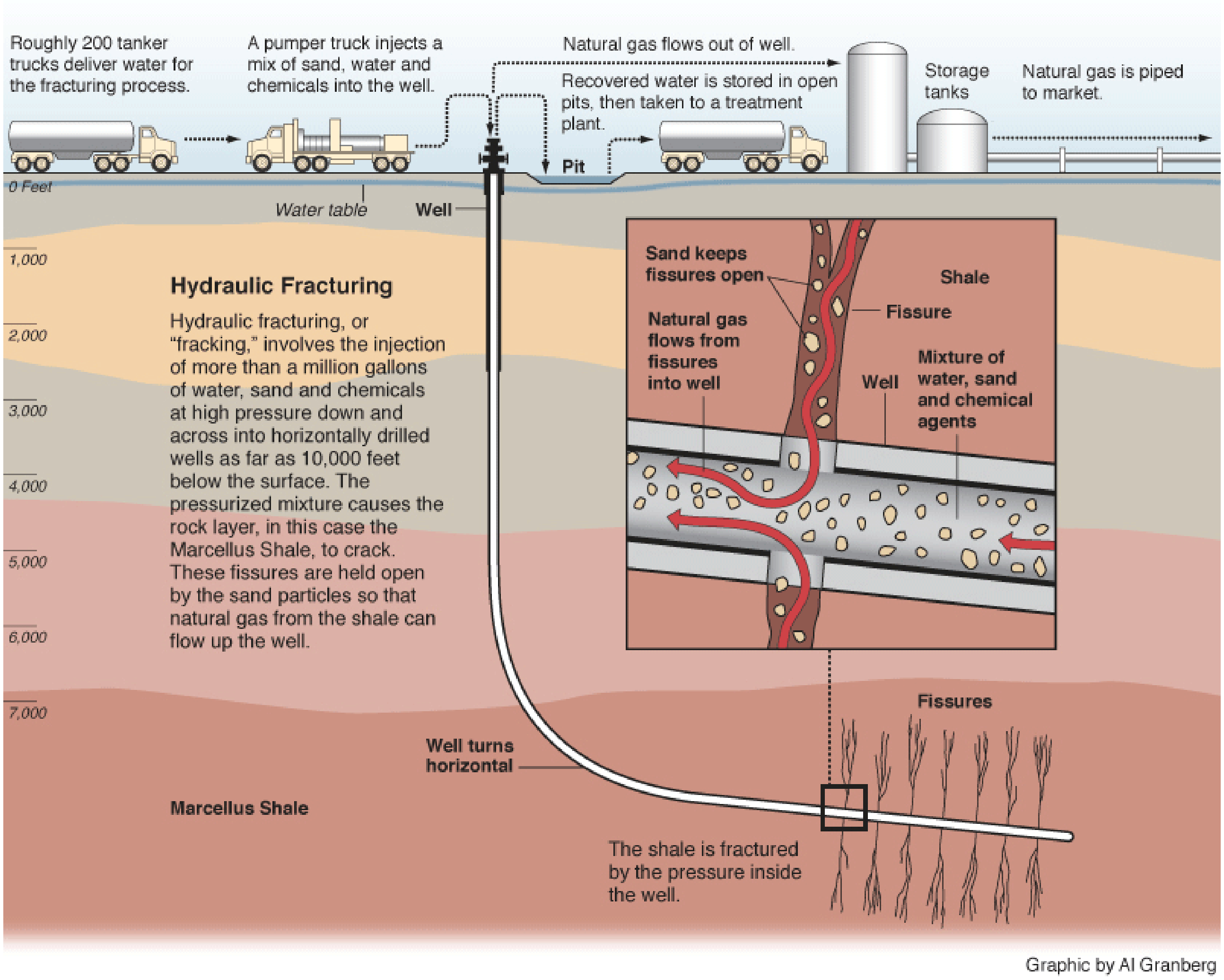
1.6 Our Awards

ProPublica was a recipient of the 2011 Pulitzer Prize in National Reporting and a 2010 Pulitzer Prize in Investigative Reporting. See a full list of our awards.

2.0 What Is Hydraulic Fracturing?

Hydraulic fracturing is a process used in nine out of 10 natural gas wells in the United States, where millions of gallons of water, sand and chemicals are pumped underground to break apart the rock and release the gas.

Scientists are worried that the chemicals used in fracturing may pose a threat either underground or when waste fluids are handled and sometimes spilled on the surface.

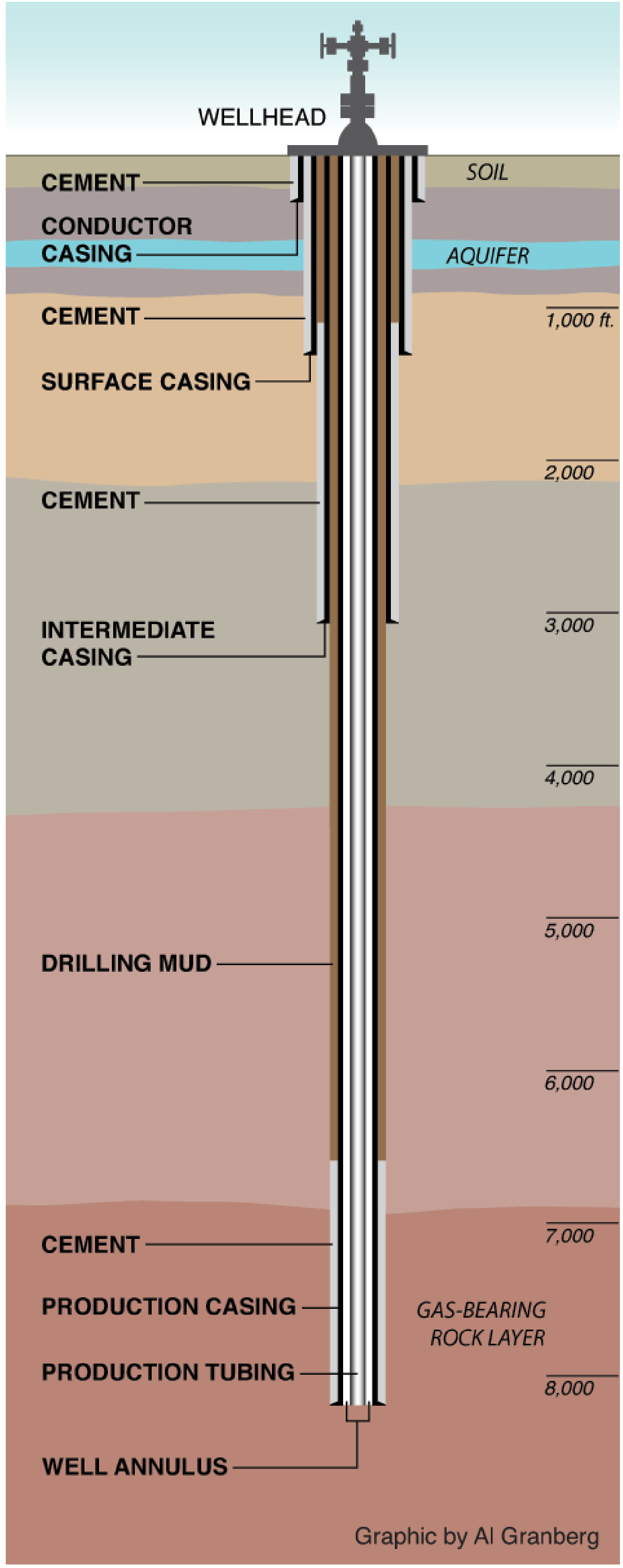


3.0 Gas Drilling: The Story So Far

The country's push to find clean domestic energy has zeroed in on natural gas, but cases of water contamination have raised serious questions about the primary drilling method being used.

Vast deposits of natural gas, large enough to supply the country for decades, have brought a drilling boom stretching across 31 states. The drilling technique being used, called hydraulic fracturing, shoots water, sand and toxic chemicals into the ground to break up rock and release the gas. The Environmental Protection Agency has declared the process to be safe, but water contamination has been reported in more than a thousand places where drilling is happening. Gas companies, exempt from federal laws protecting water supplies, may conceal the identities of their chemicals as trade secrets, making it [difficult to determine] the cause of contamination.

The EPA is now conducting [a deeper study] of the drilling, New York state has [blocked drilling] in New York City's watershed, and lawmakers are pushing for closer oversight of the industry. The industry -- in the form of millions of dollars spent on lobbying, a slew of court cases, and a robust public relations campaign -- [is pushing back].



Anatomy of a gas well: Several layers of steel casing typically enclose a well bore. The empty spaces between can be sealed with cement.

4.0 Fracking – Gas Drilling's Environmental Threat

The following pages contain journalistic articles from ProPublica's investigative series: "Fracking – Gas Drilling's Environmental Threat". While the webpage contains an extensive archive of these articles, the documents contain herein are from 2012 through August 2013.

4.1 2012-01-13 _ EPA Sees Risks to Water, Workers In New York Fracking Rules

by Joaquin Sapien *ProPublica, Jan. 13, 2012, 2:11 p.m.*

New York's emerging plan to regulate natural gas drilling in the gas-rich Marcellus Shale needs to go further to safeguard drinking water, environmentally sensitive areas and gas industry workers, the U.S. Environmental Protection Agency has informed state officials.

The EPA's comments, in a series of letters [1] this week to the state's Department of Environmental Conservation, are significant because they suggest the agency will be watching closely as states in the Northeast and Midwest embrace new drilling technologies to tap vast reserves of shale gas.

New York is in the forefront of the shale gas boom and has been working on regulations for more than three years. Judith Enck, the EPA regional administrator who issued the agency comments, noted that New York "will help set the pace for improved safeguards across the country."

The EPA's comments are among 20,000 the state has received on its proposed plan to regulate the environmental effects of drilling. Many of the EPA's comments focus on how the state DEC will handle the chemically tainted wastewater from the drilling process known as hydraulic fracturing, or fracking.

To free the gas trapped in the Marcellus and other shale formations, drillers pump millions of gallons of water mixed with sand and chemicals deep underground under pressure. The wastewater can get into drinking water by being disposed of at sewage treatment plants, the EPA wrote.

As ProPublica first reported [2] in 2009, these plants don't typically have the equipment necessary to detect and treat the chemicals in drilling wastewater. Plant operators who accept drilling wastewater simply dilute it with regular sewage and then discharge it into water bodies. DEC wastewater samples had levels of radioactive elements thousands of times higher than drinking water limits, ProPublica reported [3].

In its comments, the EPA pointed out that New York's current permitting system for water treatment plants doesn't include limits on pollutants frequently contained in drilling wastewater, such as radionuclides, which can cause cancer at high levels.

The EPA said it needs to be more closely involved in analyzing and approving any treatment plant's application to accept drilling wastewater. And while the DEC's proposed rules suggest limits on radioactive elements such as radium, the EPA said it's not clear who would be "responsible for addressing the potential health and safety issues" related to radiation exposure.

The EPA also flagged health risks to workers close to wastewater and other potentially radioactive materials, like the large amounts of soil and mud unearthed by drilling. "At a minimum, the human health risks to the site workers from radon and its decay products should be assessed along with the associated treatment technologies such as aeration systems or holding for decay," the agency wrote.

The EPA raised concerns about the sheer amount of wastewater. To deal with the excess water, the DEC listed a number of out-of-state treatment plants as potential recipients, but the EPA warned that several of the plants probably don't have the capacity to handle more wastewater.

ProPublica reported [2] that neighboring Pennsylvania became overwhelmed by drilling wastewater after the state embraced the industry.

The Monongahela River, which provides drinking water to 350,000 people, became contaminated with drilling salts and minerals.

The EPA letters are the latest in a series of federal moves to tighten oversight of gas drilling. In December, the agency scientifically linked [4] underground water pollution to hydraulic fracturing for the first time. Last August, the EPA announced [5] that it would develop its own rules on wastewater disposal instead of leaving it up to states.

Industry and green groups have split over the DEC's proposed regulations, with drillers saying they are too restrictive and environmentalists contending they don't go far enough. Meantime, the EPA has launched a comprehensive review of the environmental impacts of hydrofracking.

In August, DEC Commissioner Joe Martens told ProPublica that he didn't think there would be much to learn from the EPA study and that the state was far ahead of the federal agency in its response to drilling.

4.2 2012-01-20 _ Years After Evidence of Fracking Contamination, EPA to Supply Drinking Water to Homes in Pa. Town

by Abrahm Lustgarten *ProPublica, Jan. 20, 2012, 1:58 p.m.*

First, the earth around the rural town of Dimock, Pa., was cracked open as gas drillers used fracking [1] to tap the vast energy supplies of the Marcellus Shale.

Then, in April 2009, residents there lost their access to fresh drinking water [2]. Wells turned fetid. Some blew up. Tap water caught fire.

Now, nearly three years later — and after a string of lawsuits and state investigations has ushered Dimock to the forefront of the environmental debate over drilling but failed to resolve the water problem — the Environmental Protection Agency is stepping in to supply drinking water itself.

On Friday, the agency announced it would bring tanks of drinking water to four homes, including that of Julie Sautner, whom ProPublica first interviewed [3] about her water problems in 2009.

"Data reviewed by EPA indicates that residents' well water contains levels of contaminants that pose a health concern," the agency said in a statement [4]. Tests showed dangerous levels of arsenic [5], a carcinogen, as well as glycols and barium in at least four wells, and the EPA is apparently concerned that the contamination may be more widespread.

According to the statement, the EPA plans to test the water supplies in 60 additional homes for hazardous substances.

In 2009, Pennsylvania officials charged Cabot Oil & Gas [6], the company that drilled the wells in Dimock, with several violations it said had contributed to methane gas leaking out of the gas wells and into drinking water. For a time, Cabot supplied drinking water to a number of homes in the area but then stopped.

The EPA has waded into the Dimock issues slowly over the past few months, provoking a defensive stance from the state's lead environmental regulator, who earlier this month called the EPA's understanding of the Dimock situation "rudimentary [7]."

But the state has not undertaken the scope of water analysis the EPA now plans to do, and until the EPA stepped in Friday, Dimock residents had found little resolution.

Environmental groups are applauding the EPA's move. "This finding confirms what Dimock residents have said for months, that the Pennsylvania Department of Environmental Protection should have never allowed Cabot to end deliveries of clean water," said Environmental Working Group senior counsel Dusty Horwitt. But they also say the time has come for the EPA to address water contamination concerns in other communities across the country where residents say drilling has harmed their water.

In December, the EPA concluded that fracking [8] was likely to blame for a similar rash of groundwater contamination in Pavillion, Wyo.

The agency is conducting a multiyear national study of fracking's effects on water supplies.

We have previously reported about water and drilling concerns [9] in parts of western Wyoming, as well as central and southern Colorado, Texas, Ohio and elsewhere.

1. http://www.propublica.org/series/fracking
2. http://www.propublica.org/article/officials-in-three-states-pin-water-woes-on-gas-drilling-426
3. http://www.propublica.org/special/the-faces-of-dimock-426
4. http://yosemite.epa.gov/opa/admpress.nsf/0/8EB78248CE13D9DC8525798A0070F991
5. http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%2001-19-12.PDF
6. http://www.propublica.org/article/pennsylvania-tells-drilling-company-to-clean-up-its-act-1106
7. http://thetimes-tribune.com/news/dep-head-calls-epa-knowledge-of-dimock-rudimentary-1.1255658
8. http://www.propublica.org/article/feds-link-water-contamination-to-fracking-for-first-time/single
9. http://www.propublica.org/drilling

4.3 2012-02-02 _ From Gung-Ho to Uh-Oh: Charting the Government's Moves on Fracking

ProPublica, Feb. 2, 2012, Feb. 27, 2012: This timeline has been corrected.

Fracking has only recently become a household word, but government involvement with the drilling technique goes back decades. President Obama has championed the potential of natural gas drilling combined with more regulation. While there has been mounting evidence of water contamination, few regulations have been implemented. The graphic below traces officials' moves -- and levels of caution -- over time.

Before 2000	2000 - 2008	2009	2010	2011
1969 The government detonates a 43 kiloton nuclear bomb deep underground in an effort to get at natural gas deposits in Colorado. The gas unlocked by "Project Rulison" is deemed too radioactive to use.	June 2004 An EPA report concludes that fracking is safe for drinking water. The report, which didn't include a scientific study, has since been criticized as politically motivated	June Congress introduces the FRAC Act, a law that would allow the EPA to regulate fracking and require companies to disclose the chemicals they pump into the ground. The bill never came to a vote.	February The House Committee on Energy and Commerce launches an investigation into the potential environmental and health impacts of fracking.	March The FRAC Act mandating more oversight is reintroduced into the House and Senate. It is still in committee.
1976 In response to energy shortages, the DOE launches the Eastern Gas Shales Project, a joint research project between state, federal, and private industrial organizations to research "unconventional" natural gas resources	August 2005 Congress passes a law prohibiting the EPA from regulating fracking under the Safe Drinking Water Act. In most other cases the law dictates what chemicals can be injected underground.	August In response to complaints of drinking water contamination, the EPA begins investigating wells in drilling areas of Pavillion, Wyoming. Initial testing finds at least three water wells that contain a chemical used for fracking.	March The EPA launches a study looking at the impacts of fracking on drinking water nationwide. The final report is due out in 2014.	April Congressional Democrats release a report stating that over the past few years gas drillers have injected millions of gallons of fluids containing potentially toxic chemicals into the ground.
1986 As part of an early federal effort to investigate new methods of extracting natural gas, the Department of Energy sponsors the drilling of a 2,000-foot horizontal well in the Devonian shales of Wayne	August 2005 The Ultra- Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program is established to develop technologies to increase national oil and gas	October The Obama Administration rescinds the 2007 memo that loosened restrictions on air pollution caused by drilling.	December The Department of the Interior holds a forum to discuss the impact of current drilling practices and to consider a policy requiring companies to disclose the chemicals they use for fracking.	May A federal panel releases a report concluding that current fracking regulations may not be enough to protect the environment and public health. That same month, Congress introduces the BREATHE act,

(continued) County, WV.	*(continued)* production and reduce dependency on imports.		*(continued)* President Obama has spoken in support of such a policy, but no official rules have been implemented.	*(continued)* which would give the EPA power to regulate air pollution from fracking. It has yet to pass.
1994 The Legal Environmental Assistance Foundation uses the Safe Water Drinking Act to challenge the EPA's decision not to regulate fracking in Alabama. The EPA maintains that it is under no such legal requirement. Two years later, the case reaches a federal appeals court which rules against the EPA, saying the agency is in fact required to regulate fracking (at least in Alabama). The decision prompts an effort to exempt fracking from regulation, and in 2005, an exemption is passed by Congress.	January 2007 A Bush Administration memo effectively loosens the limits on air pollution from many natural gas wells.	December In a controversial decision, the Bureau of Land Management approves gas drilling within a three mile buffer zone of a radioactive Colorado site, the home of the 1960's nuclear test Project Rulison.		July 2011 The EPA proposes a set of regulations to reduce harmful air pollution from oil and natural gas production, specifically targeting compounds released by fracking. The regulations have not yet been adopted.
	October 2008 The Department of Energy funds AltaRock, a project to extract renewable energy from hot bedrock by fracking more than two miles deep. The test, which a year later the Obama administration makes its first major geothermal venture, is cancelled quickly due to, among other things, concerns about causing an earthquake.			October The EPA announces a plan to issue new national rules for fracking wastewater. The process is still in its early stages, and the EPA is currently simply soliciting input.

				November In response to a petition by environmental groups, the EPA agrees to develop rules requiring companies to test and submit data on the chemicals they use for fracking. Again the rules are not yet set.
				December An EPA draft report concludes that contaminants in Pavillion, Wyoming most likely seeped up from gas wells, scientifically linking water contamination to fracking for the first time.

Sources: Environmental Protection Agency, Department of Energy, Bureau of Land Management, Department of the Interior, The Sierra Club.

Correction: We originally placed the AltaRock entry in 2009. We've moved it to 2008 because that's when the DOE initially funded the project. We also made a few clarifications: Readers have pointed out that the name used to refer to the project, AltaRock, is also the name of the company running it. While there was much concern about the project causing an earthquake, the Department of Energy says drilling difficulties forced a project shutdown first.

4.4 2012-02-16 _ Federal Rules to Disclose Fracking Chemicals Could Come with Exceptions

by Lena Groeger *ProPublica, Feb. 16, 2012, 2:44 p.m.*

Last week several [1] media [2] outlets [3] obtained the federal Bureau of Land Management's draft of proposed rules [4] requiring fracking companies to disclose the chemicals they pump into the ground. Such disclosure requirements have been championed by environmentalists for years and were endorsed by President Obama in the State of the Union [5], but critics say the rules may not go far enough.

In the process of fracking, or hydraulic fracturing, millions of gallons of highly pressurized water, mixed with sand and other chemicals, are injected into the ground to extract natural gas from rock. As we've noted before, some of these chemicals are toxic to humans [6] and have contaminated nearby groundwater [7]. Some energy companies have voluntarily made their chemical information public [8], but others have fought to keep them secret.

InsideClimate notes [1] that the proposed national rules would specifically require companies to give both the names and concentrations [9] of individual chemicals used. So far, Colorado is the only state that requires such detailed information for all chemicals; eight other states with fracking disclosure rules either do not require companies to report concentrations or only require them to report concentrations of hazardous materials. The BLM's rules also would compel companies to report the total volume of fracking fluid used, as well as how they intend to recover and dispose of it [10].

Though the BLM's proposed rules are more stringent than most state laws, environmental and health advocates say drillers could circumvent some of the requirements. For instance, the rules would only apply to drilling on federal lands. Also, companies could request that certain chemicals be exempted from disclosure if they are deemed a "trade secret." The trade secret exemptions "could potentially make the rules meaningless if applied broadly," Dusty Horwitt [11], senior counsel at a public health advocacy group told InsideClimate [1].

While the BLM's proposal states that all the non-exempted information would "become a matter of public record," it makes no mention of how or where the disclosure information would appear -- or how it would be made available to the public.

To compare the BLM's draft rules with state disclosure provisions, take a look at the table here [12] (which we've recreated from a chart by InsideClimate [13]). You can also read the full draft legislation here [4].

1. http://insideclimatenews.org/news/20120215/blm-fracking-chemicals-disclosure-hydraulic-fracturing-proprietary-natural-gas-drilling
2. http://trib.com/news/state-and-regional/first-ever-federal-fracking-rules-draw-mixed-wyoming-reviews/article_d0c16030-a105-51bf-8727-7c7aea09f031.html
3. http://www.timesunion.com/news/article/Fracking-rules-raise-tension-3087489.php
4. http://www.propublica.org/documents/item/293076-blm-draft-rule
5. http://www.politico.com/news/stories/0112/71920.html
6. http://www.propublica.org/article/fracking-chemicals-cited-in-congressional-report-stay-underground
7. http://www.propublica.org/article/feds-link-water-contamination-to-fracking-for-first-time
8. http://fracfocus.org/
9. http://www.propublica.org/documents/item/293076-blm-draft-rule#document/p2/a45109
10. http://www.propublica.org/documents/item/293076-blm-draft-rule#document/p2/a45110
11. http://www.ewg.org/about/staff
12. http://www.propublica.org/special/fracking-chemical-disclosure-rules
13. http://insideclimatenews.org/sites/default/files/FrackingDisclosureLawsStatesandBLM_INSIDECLIMATENEWS.pdf

4.5 2012-02-22 _ New York Court Affirms Towns' Powers to Ban Fracking

by Lena Groeger *ProPublica, Feb. 22, 2012, 4:51 p.m.*

In a decision that could set a national precedent for how local governments can regulate gas drilling, a New York state court yesterday ruled for the first time that towns have the right to ban drilling despite a state regulation asserting they cannot.

At issue was a zoning law in Dryden, a township adjacent to Ithaca and the Cornell University campus, where drilling companies have leased some 22,000 acres for drilling. In August, Dryden's town board passed a zoning law that prohibits gas drilling within town limits. The next month, Denver-based Anschutz Exploration Corp. sued the town, saying the ban was illegal because state law trumped the municipal rules.
As Anschutz noted, New York law promotes the development of oil and gas resources in the state [1]. State Supreme Court Justice Phillip Rumsey addressed this point in his decision, writing [2]: "Nowhere in legislative history provided to the court is there any suggestion that the Legislature intended — as argued by Anschutz — to encourage the maximum ultimate recovery of oil and gas regardless of other considerations, or to preempt local zoning authority."

The Dryden case is merely the latest in a string of similar conflicts arising from Colorado to Pennsylvania that pit local communities against state oil and gas laws. It is common for local governments to zone industrial or commercial land, or to institute ordinances for noise or traffic. When it comes to the development of natural resources like oil and gas, the industry contends that local government shouldn't make those decisions.

In New York, the controversy over state regulation of fracking has been brewing for years. In 2008, New York effectively put drilling on hold [3] while it launched an environmental analysis of fracking, a process that uses a mix of highly pressurized water, sand and other chemicals to crack the earth deep underground. This is the first ruling on an industry effort to use the mineral extraction law to get around local bans.

In addition to the environmental and health concerns over fracking, which we've covered in depth [4], a fundamental issue has been the rights of localities against state or federal laws. According to Eric Goldstein, a senior attorney for the Natural Resources Defense Council in New York, the right of local governments to determine their own land use has been guaranteed by the Constitution for over a century.

"The argument is simple," said Goldstein. "New York state laws shouldn't override the authority of local governments to protect their constituents."

In New York, two very similarly worded laws govern the regulation of mining and oil and gas drilling [1]. The oil and gas provision gives the state the power to "regulate the development, production and utilization of natural resources of oil and gas [5]." The town of Dryden argued that it was not trying to regulate fracking but merely trying to protect its citizens and property. It pointed out that courts have allowed towns to ban mining, and said Dryden should be allowed to do the same for fracking. The justice seemed to agree, concluding that the state's oil and gas laws don't prohibit localities from barring drilling.

Anschutz's lawyer, Thomas West, said he was not sure whether the company would appeal the decision. Even if it does so, said Joseph Heath, an environmental attorney in New York, Tuesday's win could help set a precedent for other communities. Despite the threat of similar lawsuits from a major corporation, local fracking bans and moratoriums have continued to grow [6] in the last few years.

"People are now concentrating on local governments because that's the best form of protection against fracking," said Heath.

Such protection is unlikely to come from the states, as New York's Department of Environmental Conservation has already deferred to the courts. When ProPublica interviewed the commissioner last year [7], we asked him specifically about the potential for conflict between local municipalities and states. He said it was likely "that the courts will need to decide these issues in a lawsuit between the town and the drilling company, not the state." Now, it looks as if at least one court has decided.

"[The Dryden case] is an important indicator of how those battles are likely to play out," said the NRDC's Goldstein, "although it's not the final word."

1. http://www.dec.ny.gov/lands/2417.html
2. http://www.propublica.org/documents/item/296966-anschutz-exploration-corp-v-town-of-dryden.html#document/p18/a45735
3. http://www.propublica.org/article/fracking-still-on-hold-in-new-york-pending-environmental-review
4. http://www.propublica.org/article/feds-link-water-contamination-to-fracking-for-first-time
5. http://www.dec.ny.gov/energy/26498.html

6. http://www.propublica.org/article/lawsuits-predicted-as-new-york-towns-ponder-whether-to-block-fracking
7. http://www.propublica.org/article/new-york-environment-commissioner-expects-little-from-epa-fracking-study

4.6 2012-03-07 _ What the Frack is in That Water?

Environmentalists have repeatedly pressed regulators to compel oil and gas companies to report what chemicals they use in the drilling and fracking process. Drilling companies add these chemicals to perform particular functions (for example, to prevent corrosion or give the fluid the right consistency), or leave them in because they're too expensive to remove. According to a 2011 congressional report, many of the chemicals used can pose a serious health risk. No one knows the exact makeup of the frack mixture, drilling muds and other stuff used at well sites (which change from well to well), but this list breaks down the main ingredients revealed so far.

<u>Most Commonly Found</u>

Water

Water makes up 98% to 99.5% of fracking fluid.

Crystalline silica

Found in concrete, brick mortar and construction sands.

Dust is harmful if inhaled repeatedly over a long period of time and can lead to silicosis or cancer.

Methanol

Found in antifreeze, paint solvent and vehicle fuel.

Vapors can cause eye irritation, headache and fatigue, and in high enough doses can be fatal. Swallowing may cause eye damage or death.

Isopropanol

Found in glass cleaners, antiperspirant, cosmetics, perfumes and soaps.

Vapors can cause irritation of the eyes and the upper respiratory tract. Ingestion causes drunkenness and vomiting.

Hydrotreated light distillate

Found in the fuel for the US Air Force's U-2 Aircraft.

In acute cases can cause skin and eye irritation, headache and dizziness. Long term exposure can damage liver, kidneys or blood.

2-Butoxyethanol

Found in paints and varnish.

Vapors irritate the eyes and nose. Ingestion or skin contact can cause headache, nausea, vomiting and dizziness.

Ethylene glycol

Found in de-icing agents, automotive antifreeze, household cleaners.

Ingestion causes stupor or coma and can lead to fatal kidney injury.

Diesel

Found in fuel oil.

Contact with skin may cause redness, itching, burning, severe skin damage and cancer.

Sodium hydroxide (lye)

Found in drain cleaner, manufacturing products.

Dust may cause damage to lungs. Exposure to solid or liquid forms can severely burn the eyes, skin and mucous membranes, or lead to death.

Naphthalene

Found in mothballs.

Inhalation can cause respiratory tract irritation, nausea, vomiting, abdominal pain, fever or death.

Serious Health Hazards

Formaldehyde

Found in embalming agent for human or animal remains.

Ingestion of even one ounce of liquid can cause death. Exposure over a long period of time can cause lung damage and reproductive problems in women.

Sulfuric acid

Found in lead-acid batteries for cars.

Corrosive to all body tissues. Inhalation may cause serious lung damage and contact with eyes can lead to a total loss of vision. The lethal dose is between 1 teaspoonful and one-half ounce. It has been classified as a probable carcinogen.

Benzene

Found in gasoline.

Long time exposure can cause cancer, bone marrow failure, or leukemia. Short term effects include dizziness, weakness, headache, breathlessness, chest constriction, nausea, and vomiting.

Lead

Found in paint, building construction materials and roofing joints.

Can damage the nervous system and lead to brain and blood disorders. Lead poisoning typically results from ingestion of contaminated food or water.

Boric acid

Found in insecticides, antiseptics, flame retardants.

Poisonous if taken internally or inhaled in large quantities. Long term exposure can cause kidney damage and eventual kidney failure.

Fuel oil #2

Found in heating oil.

Harmful if swallowed. May cause dizziness, drowsiness, eye and skin irritation. Long-term exposure may cause skin cancer.

Kerosene

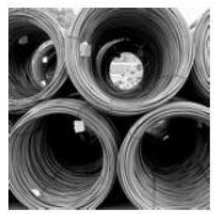
Found in jet and rocket fuel.

Vapor can cause irritation of the eyes and nose, and ingestion can be fatal. Chronic exposure may cause drowsiness, convulsions, coma or death

Hydrofluoric acid

Found in rust removers, aluminum brighteners and heavy duty cleaners.

Fumes are highly irritating, corrosive, and poisonous. Repeated ingestion over time can lead to hardening of the bones, and contact with liquid can produce severe burns. A lethal dose is 1.5 grams.



Hydrochloric acid

Used in the treatment of steel, found in household cleaners and stomach acid.

Corrosive to tissues and will irritate eyes. Inhaling fumes can be dangerous and lead to respiratory problems. Prolonged exposures will result in death.

Formic acid

Used for tanning leather, as a preservatives for livestock feed, and in toilet bowl cleaner.

Liquid causes skin and eye burns. Inhaling vapors can be irritating and painful, and may cause nausea and vomiting.

Clarification: Readers have pointed out that sulfuric acid is not a definite human carcinogen. We've listed it as a probable carcinogen because according to the International Agency for Research on Cancer, "occupational exposure to strong inorganic acid mists containing sulfuric acid is carcinogenic to humans."

Just Plain Weird


Instant coffee


Paraffin wax


Walnut hulls


Essential oils


Tallow soap


Starch


Resin


Coconut fatty acid


Pine oil


Guar gum

Sources: Department of Energy, TEDX, House Committee on Energy and Commerce, FracFocus

Images: Flickr: Allan Foster,Windell Oskay, EvelynGiggles, Je Kemp, Jack Snell, hojun song, Anthony Easton, Francis Mariani, Brittney Bush Bollay, C Jill Reed, Linden Tea, Andy Armstrong, Bruno Furnari, Tim Patterson, Massachusetts Dept. of Environmental Protection, Greg Bishop, David Hawkins-Weeks, Kristin Kokkersvold, Nic McPhee, chrisplymouth, Bc. Jan KalÃ¡b, Bill Rhodes, Henna by Heather, Marilyn Sherman, Artizone, Francesco Lodolo, Srinayan Puppala, anemoneprojectors, stu_spivack, and Wikimedia Commons: Thester11

4.7 2012-03-20 _ So, Is Dimock's Water Really Safe to Drink?

Ray Kemble delivers fresh water to a home that had their water contaminated due to hydraulic fracturing on Jan. 18, 2012 in Dimock, Pa. Photo by Spencer Platt/Getty Images.

by Abrahm Lustgarten *ProPublica, March 20, 2012, 12:42 p.m.*

March 21: This post has been corrected [1].

When the Environmental Protection Agency announced last week that tests showed the water is safe to drink in Dimock, Penn., a national hot spot for concerns about fracking, it seemed to vindicate the energy industry's insistence that drilling had not caused pollution in the area.

But what the agency didn't say – at least, not publicly – is that the water samples contained dangerous quantities of methane gas, a finding that confirmed some of the agency's initial concerns and the complaints raised by Dimock residents since 2009.

The test results also showed the group of wells contained dozens of other contaminants, including low levels of chemicals known to cause cancer and heavy metals that exceed the agency's "trigger level" and could lead to illness if consumed over an extended period of time. The EPA's assurances suggest that the substances detected do not violate specific drinking water standards, but no such standards exist for some of the contaminants and some experts said the agency should have acknowledged that they were detected at all.

"Any suggestion that water from these wells is safe for domestic use would be preliminary or inappropriate," said Ron Bishop, a chemist at the State University of New York's College at Oneonta, who has spoken out about environmental concerns from drilling.

Dimock residents are struggling to reconcile the EPA's public account with the results they have been given in private.

"I'm sitting here looking at the values I have on my sheet – I'm over the thresholds – and yet they are telling me my water is drinkable," said Scott Ely, a Dimock resident whose water contains methane at three times the state limit, as well as lithium, a substance that can cause kidney and thyroid disorders. "I'm confused about the whole thing… I'm flabbergasted."

The water in Dimock first became the focus of international attention after residents there alleged in 2009 that natural gas drilling, and fracking, had led to widespread contamination. That April, ProPublica reported [2] that a woman's drinking water well blew up.

Pennsylvania officials eventually determined [3] that underground methane gas leaks had been caused by Cabot Oil and Gas, which was drilling wells nearby. Pennsylvania sanctioned Cabot, and for a short time the company provided drinking water to households in the Dimock area.

This January, the EPA announced [4] it would take over the state's investigation, testing the water in more than 60 homes and agreeing to provide drinking water to several of families – including the Elys – in the meantime.

Then, last Thursday, the EPA released a brief statement saying that the first 11 samples to come back from the lab "did not show levels of contamination that could present a health concern." The agency noted that some metals, methane, salt and bacteria had been detected, but at low levels that did not exceed federal thresholds. It said that arsenic exceeding federal water standards was detected in two samples.

But Dimock residents say the agency's description didn't jibe with the material in test packets distributed to them, and they voiced concerns about why the EPA had passed judgment before seeing results from nearly 50 homes. Several shared raw data and materials they were given by the EPA with Josh Fox, the director of the Academy Award-nominated documentary "GasLand," who shared them with ProPublica.

EPA press secretary Betsaida Alcantara said the agency was trying to be forthcoming by giving the tests results to Dimock residents and is now considering whether to release more information to the public about the water samples. "We made a commitment to the residents that
we would give them the information as soon as we had it," she said. "For the sake of transparency we felt it was the right thing to do."

However preliminary, the data is significant because it is the first EPA research into drilling-related concerned on the east coast, and the agency's first new information since it concluded that there was likely a link [5] between fracking and water contamination in central Wyoming last December. The EPA is currently in the midst of a national investigation into the effects of fracking on groundwater, but that research is separate.

As the agency has elsewhere, the EPA began the testing in Dimock in search of methane and found it.

Methane is not considered poisonous to drink, and therefore is not a health threat in the same way as other pollutants. But the gas can collect in confined spaces and cause deadly explosions, or smother people if they breathe too much of it. Four of the five residential water results obtained by ProPublica show methane levels exceeding Pennsylvania standards; one as high as seven times the threshold and nearly twice the EPA's less stringent standard.

The methane detections were accompanied by ethane, another type of natural gas that experts say often signifies the methane came from deeply buried gas deposits similar to those being drilled for energy and not from natural sources near the surface.

Among the other substances detected at low levels in Dimock's water are a suite of chemicals known to come from some sort of hydrocarbon substance, such as diesel fuel or roofing tar. They include anthracene, fluoranthene, pyrene and benzo(a)pyrene– all substances described by a branch of the Centers for Disease Control and Prevention as cancer-causing even in very small amounts.

Chromium, aluminum, lead and other metals were also detected, as were chlorides, salts, bromide and strontium, minerals that can occur naturally but are often associated with natural gas drilling.

It is unclear whether these contaminants have any connection to drilling activities near Dimock. The agency says it plans further testing and research.

Many of the compounds detected have not been evaluated for exposure risk by federal scientists or do not have an exposure limit assigned to them, making it difficult to know whether they present a risk to human health.

Inconsistencies in the EPA's sampling results also are raising concerns. EPA documents, for example, list two different thresholds for the detection of bromide, a naturally occurring substance sometimes used in drilling fluids, opening up the possibility that bromide may have been detected, but not reported, in some tests.

"The threshold that it is safe, that shouldn't be changing," said Susan Riha, director of the New York State Water Resources Institute and a professor of earth sciences at Cornell University. "For some reason … one was twice as sensitive as the other one."

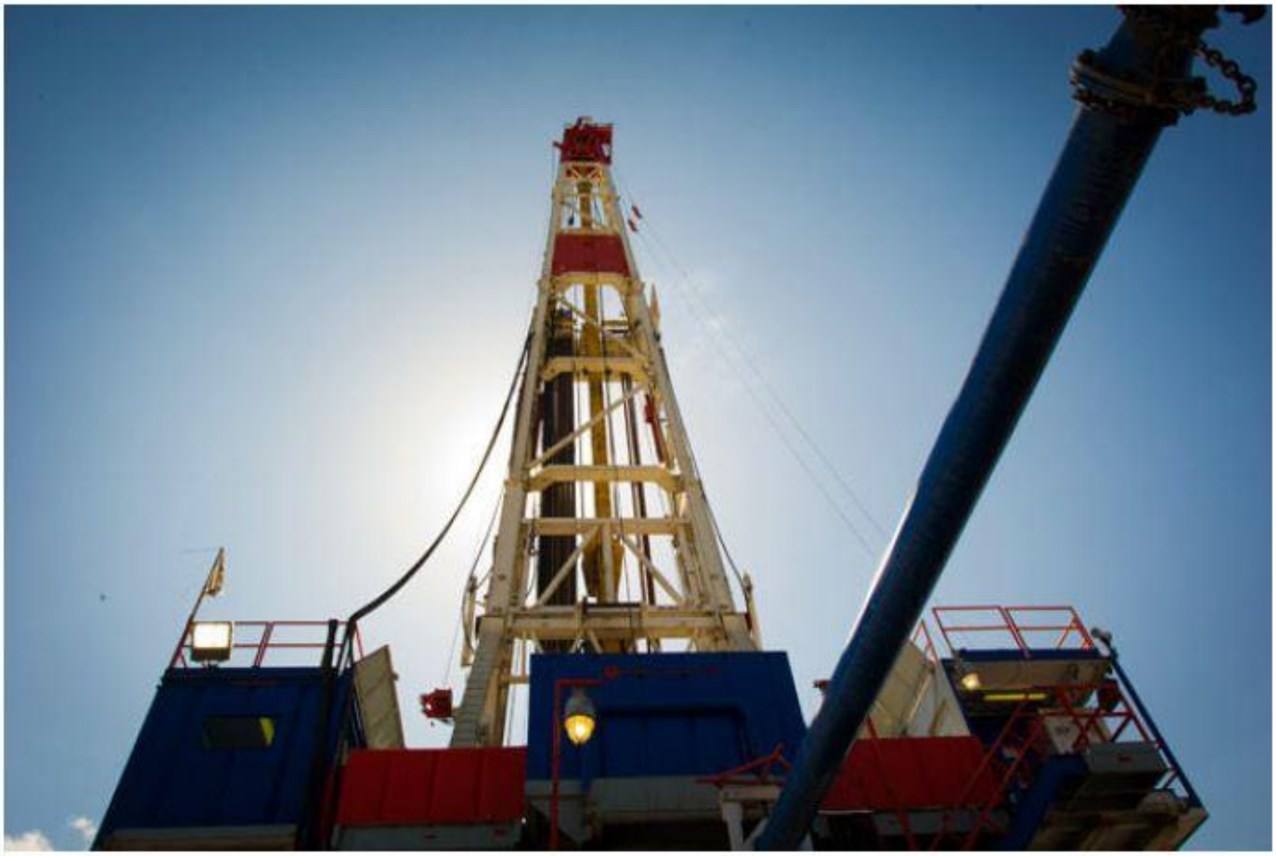
The EPA did not respond to questions about the detection limits, or any other technical inquiries about the test data [5].

A spokesman for Cabot declined to comment on the water test results or their significance, saying that he had not yet seen the data.

Correction: This post said EPA tests had detected bromium in some Dimock water wells. It should have said bromide. Also, the post identified Susan Riha as the director of the New York State Water Resources Group. She is the director of the Water Resources Institute at Cornell University.

1. #bromide_riha
2. http://www.propublica.org/article/officials-in-three-states-pin-water-woes-on-gas-drilling-426
3. http://s3.amazonaws.com/propublica/assets/natural_gas/final_cabot_co-a.pdf
4. http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%2001-19-12.PDF
5. https://www.documentcloud.org/documents/326876-hw12-epa-report-water-test-results-binder-dimock.html

4.8 2012-04-24 _ ALEC and ExxonMobil Push Loopholes in Fracking Chemical Disclosure Rules



A Consol Energy gas drilling rig outside Waynesburg, Pa.
(Mladen Antonov/AFP/Getty Images)

by Cora Currier *ProPublica, April 24, 2012, 12:06 p.m.*

One of the key controversies about fracking is the chemical makeup of the fluid [1] that is pumped deep into the ground [2] to break apart rock and release natural gas. Some companies have been reluctant to disclose what's in their fracking fluid. Scientists and environmental advocates argue that, without knowing its precise composition [3], they can't thoroughly investigate complaints of contamination.

Disclosure requirements vary considerably from state to state, as ProPublica recently charted [4]. In many cases, the rules have been limited by a "trade secrets" provision under which companies can claim that a proprietary chemical doesn't have to be disclosed to regulators or the public.

One apparent proponent of the trade secrets caveat? The American Legislative Exchange Council, better known as ALEC, a nonprofit group that brings together politicians and corporations [5] to draft and promote conservative, business-friendly legislation. ALEC has been in the spotlight recently [6] because of its support of controversial laws like Florida's "Stand Your Ground" provision.

This weekend, as part of a story on ALEC's political activity [7], The New York Times noted that the group recently adopted "model legislation" on fracking chemical disclosure, based on a bill passed in Texas last year. According to The Times, the model bill was "sponsored within ALEC" by ExxonMobil, which runs a major oil and gas operation through its subsidiary, XTO Energy. The advocacy group Common Cause, which provided the documents on ALEC's lobbying efforts to The Times, describes model legislation, in many cases identifying by name [8] the company that proposed it to ALEC's task forces.

ALEC has recently removed its list of model bills from its main website, and did not respond to requests for comment. A spokesman for XTO Energy confirmed that the company is a member of ALEC, but he did not provide details on the company's involvement with the disclosure bill.

The spokesman said ExxonMobil supports "full disclosure of the ingredients and additives in hydraulic fracturing fluids," but added that when vendors request it, ExxonMobil has "respected the trade secret status of their products." Last year, the company began voluntarily uploading chemical disclosures [9] to FracFocus [10], a clearinghouse website run by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission.

In a recent blog post [11], ALEC claimed that legislators in Pennsylvania, Illinois, Indiana, New York and Ohio have introduced versions of its model bill, but many of those states vary in the level of disclosure required [4] and how they handle the trade secrets provision. Laws in 11 states require at least partial disclosure [12], and the Bureau of Land Management recently drafted disclosure guidelines [13] for drilling on federal land.

These laws have been relatively well-received [14] by environmental advocates, though the trade secrets issue remains a concern for some. In Ohio, for example, proprietary chemicals don't have to be disclosed to regulators or the public. In Pennsylvania, they are disclosed to regulators, and the public can request information on them from the state Department of Environmental Protection on a case-by-case basis.

The Texas law, which ALEC cites in the post as its template, codifies the trade secrets exemption, and who can challenge it: The "trade secret" exemption (p. 3) [15]

Otherwise, Texas' law requires [4] that companies post disclosure forms for each completed well on the FracFocus site. They must disclose all chemicals but only report the concentrations of those that are hazardous. The law also requires that the companies give the total volume of water used in fracking.

The Environmental Protection Agency cannot regulate fracking in order to protect groundwater, because in 2005 Congress exempted fracking [16] from the Safe Drinking Water Act, which controls how industries inject substances underground.

According to ALEC's blog [11], the model disclosure legislation is designed to promote "responsible resource production" and "aims to preempt the promulgation of duplicative, burdensome federal regulations" from the EPA, in particular. ALEC has consistently opposed any federal control over fracking. In 2009, the group adopted a "Resolution to Retain State Authority Over Hydraulic Fracturing [17]."

1. http://www.propublica.org/special/what-the-frack-is-in-that-water
2. http://www.propublica.org/special/hydraulic-fracturing-national
3. http://www.propublica.org/article/critics-find-gaps-in-state-laws-to-disclose-hydrofracking-chemicals
4. http://www.propublica.org/special/fracking-chemical-disclosure-rules
5. http://www.propublica.org/blog/item/a-discreet-nonprofit-brings-together-politicians-and-corporations-to-write-
6. http://www.huffingtonpost.com/2012/04/17/alec-retreats-stand-your-ground-laws-voter-id_n_1431531.html
7. http://www.nytimes.com/2012/04/22/us/alec-a-tax-exempt-group-mixes-legislators-and-lobbyists.html?ref=politics
8. http://www.commoncause.org/site/pp.asp?c=dkLNK1MQIwG&b=8060297
9. http://groundwork.iogcc.org/topics-index/hydraulic-fracturing/iogcc-in-action/gwpc-and-iogcc-launch-wwwfracfocusorg
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11. http://www.americanlegislator.org/2012/03/alec-encourages-responsible-resource-production/
12. http://www.propublica.org/documents/item/346236-fracking-disclosure-crs#document/p7/a53828
13. http://www.propublica.org/documents/item/293076-blm-draft-rule

14. http://blogs.edf.org/energyexchange/author/mwatson/
15. http://www.propublica.org/documents/item/346237-texas-hb3328-on-fracking-chemical-disclosure#document/p3/a53771
16. http://www.propublica.org/article/natural-gas-politics-526
17. http://www.propublica.org/documents/item/346244-alec-resolution-to-retain-state-authority-over

4.9 2012-05-01 _ New Study Predicts Frack Fluids Can Migrate to Aquifers Within Years

A Cabot Oil and Gas hydraulic fracturing site on Jan. 17, 2012, in Springville, Pa.
(Spencer Platt/Getty Images)

by Abrahm Lustgarten *ProPublica, May 1, 2012, 2:29 p.m.*

A new study has raised fresh concerns about the safety of gas drilling in the Marcellus Shale, concluding that fracking chemicals injected into the ground could migrate toward drinking water supplies far more quickly than experts have previously predicted.

More than 5,000 wells were drilled in the Marcellus between mid-2009 and mid-2010, according to the study, which was published in the journal Ground Water [1] two weeks ago. Operators inject up to 4 million gallons of fluid, under more than 10,000 pounds of pressure, to drill and frack each well.

Scientists have theorized that impermeable layers of rock would keep the fluid, which contains benzene and other dangerous chemicals, safely locked nearly a mile below water supplies. This view of the earth's underground geology is a cornerstone of the industry's argument that fracking poses minimal threats to the environment.

But the study, using computer modeling, concluded that natural faults and fractures in the Marcellus, exacerbated by the effects of fracking itself, could allow chemicals to reach the surface in as little as "just a few years."

"Simply put, [the rock layers] are not impermeable," said the study's author, Tom Myers, an independent hydrogeologist whose clients include [2] the federal government and environmental groups.

"The Marcellus shale is being fracked into a very high permeability," he said. "Fluids could move from most any injection process."

The research for the study was paid for by Catskill Mountainkeeper and the Park Foundation, two upstate New York organizations that have opposed gas drilling and fracking in the Marcellus.

Much of the debate about the environmental risks [3] of gas drilling has centered on the risk that spills could pollute surface water or that structural failures would cause wells to leak.

Though some scientists believed it was possible for fracking to contaminate underground water supplies, those risks have been considered secondary. The study in Ground Water is the first peer-reviewed research evaluating this possibility.

The study did not use sampling or case histories to assess contamination risks. Rather, it used software and computer modeling to predict how fracking fluids would move over time. The simulations sought to account for the natural fractures and faults in the underground rock formations and the effects of fracking.
The models predict that fracking will dramatically speed up the movement of chemicals injected into the ground. Fluids traveled distances within 100 years that would take tens of thousands of years under natural conditions. And when the models factored in the Marcellus' natural faults and fractures, fluids could move 10 times as fast as that.

Where man-made fractures intersect with natural faults, or break out of the Marcellus layer into the stone layer above it, the study found, "contaminants could reach the surface areas in tens of years, or less."

The study also concluded that the force that fracking exerts does not immediately let up when the process ends. It can take nearly a year to ease.

As a result, chemicals left underground are still being pushed away from the drill site long after drilling is finished. It can take five or six years before the natural balance of pressure in the underground system is fully restored, the study found.

Myers' research focused exclusively on the Marcellus, but he said his findings may have broader relevance. Many regions where oil and gas
is being drilled have more permeable underground environments than the one he analyzed, he said.

"One would have to say that the possible travel times for a similar thing in Arkansas or Northeast Texas is probably faster than what I've come up with," Myers said.

Ground Water is the journal of the National Ground Water Association [4], a non-profit group that represents scientists, engineers and businesses in the groundwater industry.

Several scientists called Myers' approach unsophisticated and said that the assumptions he used for his models didn't reflect what they knew about the geology of the Marcellus Shale. If fluids could flow as quickly as Myers asserts, said Terry Engelder, a professor of geosciences at Penn State University who has been a proponent of shale development, fracking wouldn't be necessary to open up the gas deposits.

"This would be a huge fracture porosity," Engelder said. "So I read this and I say, 'Golly, does this guy really understand anything about what these shales look like?' The concern then arises from using a model rather than observations."

Myers likened the shale to a cracked window, saying that samples showing it didn't contain fractures were small in size and were akin to only examining an intact section of glass, while a broader, scaled out view would capture the faults and fractures that could leak.

Both scientists agreed that direct evidence of fluid migration is needed, but little sampling has been done to analyze where fracking fluids go after being injected underground.

Myers says monitoring systems could be installed around gas well sites to measure for changes in water quality, a measure required for some gold mines, for example. Until that happens, Myers said, theoretical modeling has to substitute for hard data.

"We were trying to use the basic concepts of groundwater and hydrology and geology and say can this happen?" he said. "And that had basically never been done."

1. http://onlinelibrary.wiley.com/journal/10.1111/(ISSN)1745-6584;jsessionid=BC23355888AE384813C75FF3AE8C10B9.d02t02
2. http://water.nv.gov/hearings/past/springetal/browseabledocs/exhibits%5CCTGR%20Exhibits/CTGR_EXH_006%20Statement%20of%20Qualifications%20of%20Tom%20Myers,%20Ph.D..PDF
3. http://www.propublica.org/series/fracking
4. http://www.ngwa.org/Pages/default.aspx

4.10 2012-06-07 _ North Dakota’s Oil Boom Brings Damage Along With Prosperity

An oil well near Ross, N.D., on Aug. 23, 2011. (Karen Bleier/AFP/Getty Images)

by Nicholas Kusnetz, *Special to ProPublica, June 7, 2012, 9:47 a.m.*

June 13: This post has been corrected [1] and updated [2].

Oil drilling has sparked a frenzied prosperity in Jeff Keller's formerly quiet corner of western North Dakota in recent years, bringing an infusion of jobs and reviving moribund local businesses.

But Keller, a natural resource manager for the Army Corps of Engineers, has seen a more ominous effect of the boom, too: Oil companies are spilling and dumping drilling waste onto the region's land and into its waterways with increasing regularity.

Hydraulic fracturing — the controversial process behind the spread of natural gas drilling — is enabling oil companies to reach previously inaccessible reserves in North Dakota, triggering a turnaround not only in the state's fortunes, but also in domestic energy production.

North Dakota now ranks second behind only Texas in oil output nationwide.

The downside is waste — lots of it. Companies produce millions of gallons of salty, chemical-infused wastewater, known as brine, as part of drilling and fracking each well. Drillers are supposed to inject this material thousands of feet underground into disposal wells, but some of it isn't making it that far.

According to data obtained by ProPublica, oil companies in North Dakota reported more than 1,000 accidental releases of oil, drilling wastewater or other fluids in 2011, about as many as in the previous two years combined. Many more illicit releases went unreported, state regulators acknowledge, when companies dumped truckloads of toxic fluid along the road or drained waste pits illegally.

State officials say most of the releases are small. But in several cases, spills turned out to be far larger than initially thought, totaling millions of gallons. Releases of brine, which is often laced with carcinogenic chemicals and heavy metals, have wiped out aquatic life in streams and wetlands and sterilized farmland. The effects on land can last for years, or even decades.

Compounding such problems, state regulators have often been unable — or unwilling — to compel energy companies to clean up their mess, our reporting showed.

Under North Dakota regulations, the agencies that oversee drilling and water safety can sanction companies that dump or spill waste, but they seldom do: They have issued fewer than 50 disciplinary actions for all types of drilling violations, including spills, over the past three years.

Keller has filed several complaints with the state during this time span after observing trucks dumping wastewater and spotting evidence of a spill in a field near his home. He was rebuffed or ignored every time, he said.

"There's no enforcement," said Keller, 50, an avid outdoorsman who has spent his career managing Lake Sakakawea, a reservoir created by damming the Missouri River. "None."

State officials say they rely on companies to clean up spills voluntarily, and that in most cases, they do. Mark Bohrer, who oversees spill reports for the Department of Mineral Resources, the agency that regulates drilling, said the number of spills is acceptable given the pace of drilling and that he sees little risk of long-term damage.

Kris Roberts, who responds to spills for the Health Department, which protects state waters, agreed, but acknowledged that the state does not have the manpower to prevent or respond to illegal dumping.

"It's happening often enough that we see it as a significant problem," he said. "What's the solution? Catching them. What's the problem? Catching them."

Ron Ness, president of the North Dakota Petroleum Council, a lobbying group, said the industry is doing what it can to minimize spills and their impacts.

"You're going to have spills when you have more activity," he said. "I would think North Dakotans would say the industry is doing a good job."

In response to rising environmental concerns related to drilling waste, North Dakota's legislature passed a handful of new regulations this year [3], including a rule that bars storing wastewater in open pits.

Still, advocates for landowners say they have seen little will, at either the state or federal level, to impose limits that could slow the pace of drilling.

The Obama administration is facilitating drilling projects on federal land in western North Dakota [4] by expediting environmental reviews. North Dakota's Gov. Jack Dalrymple has urged energy companies [5] to see his administration as a "faithful and long-term partner."

"North Dakota's political leadership is still in the mold where a lot of our oil and gas policy reflects a strong desire to have another oil boom," said Mark Trechock, who headed the Dakota Resource Council, a landowner group that has pushed for stronger oversight, until his retirement this year. "Well, we got it now."

Reaching 'the Crazy Point'

Keller's office in Williston is as good a spot as any to see the impacts of the oil boom.

The tiny prefab shack — cluttered with mounted fish, piles of antlers and a wolf pelt Keller bought in Alaska — is wedged between a levee that holds back Missouri River floodwaters and a new oil well, topped by a blazing gas flare. Just beyond the oil well sits an intersection where Keller estimates he saw an accident a week during one stretch last year due to increased traffic from drilling.

Keller describes the changes to his hometown in a voice just short of a yell, as if he's competing with nearby engine noise. Local grocery stores can barely keep shelves stocked and the town movie theater is so crowded it seats people in the aisle, he said. The cost of housing has skyrocketed, with some apartments fetching rents similar to those in New York City.

"With the way it is now," Keller said, "you're getting to the crazy point."

Oil companies are drilling upwards of 200 wells each month in northwestern North Dakota, an area roughly twice the size of New Jersey.

North Dakota is pumping more than 575,000 barrels of oil a day now, more than double what the state produced two years ago. Expanded drilling in the state has helped overall U.S. oil production grow for the first time in a quarter century, stoking hopes for greater energy independence.

It has also reinvigorated North Dakota's once-stagnant economy. Unemployment sits at 3 percent. The activity has reversed a population decline that began in the mid-1980s, when the last oil boom went bust.

The growth has come at a cost, however. At a conference on oil field infrastructure in October, one executive noted that McKenzie County, which sits in the heart of the oil patch and had a population of 6,360 people in 2010, required nearly $200 million in road repairs [6].

The number of spill reports, which generally come from the oil companies themselves, nearly doubled from 2010 to 2011. Energy companies report their spills to the Department of Mineral Resources, which shares them with the Health Department. The two agencies work together to investigate incidents.

In December, a stack of reports a quarter-inch thick piled up on Kris Roberts' desk. He received 34 new cases in the first week of that month alone.

"Is it a big issue?" he said. "Yes, it is."

The Health Department has added three staffers to handle the influx and the Department of Mineral Resources is increasing its workforce by 30 percent, but Roberts acknowledges they can't investigate every report.

Even with the new hires, the Department of Mineral Resources still has fewer field inspectors than agencies in other drilling states.

Oklahoma, for example, which has comparable drilling activity, has 58 inspectors to North Dakota's 19.

Of the 1,073 releases reported last year [7], about 60 percent involved oil and one-third spread brine. In about two-thirds of the cases, material was not contained to the accident site and leaked into the ground or waterways.

But the official data gives only a partial picture, Roberts said, missing an unknown number of unreported incidents.

"One, five, 10, 100? If it didn't get reported, how do you count them?" he said.

He said truckers often dump their wastewater rather than wait in line at injection wells. The Department of Mineral Resources asks companies how much brine their wells produce and how much they dispose of as waste, but its inspectors don't audit those numbers. Short of catching someone in the act, there's no way to stop illegal dumping.

The state also has no real estimate for how much fluid spills out accidentally from tanks, pipes, trucks and other equipment. Companies are supposed to report spill volumes, but officials acknowledge the numbers are often inexact or flat-out wrong. In 40 cases last year, the company responsible didn't know how much had spilled so it simply listed the volume of fluid as zero.

In one case last July, workers for Petro Harvester, a small, Texas-based oil company, noticed a swath of dead vegetation in a field near one of the company's saltwater disposal lines. The company reported the spill the next day [8], estimating that 12,600 gallons of brine had leaked.

When state and county officials came to assess the damage, however, they found evidence of a much larger accident. The leak, which had gone undetected for days or weeks, had sterilized about 24 acres of land.

Officials later estimated the spill to be at least 2 million gallons of brine, Roberts said, which would make it the largest ever in the state.

Yet state records still put the volume at 12,600 gallons and Roberts sees no reason to change it.

"It's almost like rubbing salt in a raw wound," Roberts said, criticizing efforts to tabulate a number as "bean counting." Changing a report would not change reality, nor would it help anyone, he added. "If we try to go back and revisit the past over and over and over again, what's it going to do? Nothing good."

In a written statement, Petro Harvester said tests showed the spill had not contaminated groundwater and that it would continue monitoring the site for signs of damage. State records show the company hired a contractor to cover the land with 40 truckloads of a chemical [8] that leaches salt from the soil.

Nearly a year later, however, even weeds won't grow in the area, said Darwin Peterson, who farms the land. While Petro Harvester has promised to compensate him for lost crops, Peterson said he hasn't heard from the company in months and he doesn't expect the land to be usable for years. "It's pretty devastating," he said.

Little Enforcement

The Department of Mineral Resources and the Health Department have the authority to sanction companies that spill or dump fluids, but they rarely do.

The Department of Mineral Resources has issued just 45 enforcement actions over the last three years. Spokeswoman Alison Ritter could not say how many of those were for spills or releases, as opposed to other drilling violations, or how many resulted in fines. Ritter said case files containing this information could be reviewed, but only in person in the agency's office in Bismarck, N.D.

The Health Department has taken just one action against an oil company in the past three years, citing Continental Resources for oil and brine spills that turned two streams into temporary toxic dumps [9]. The department initially fined Continental $328,500 [10], plus about $14,000 for agency costs. Ultimately, however, the state settled and Continental paid just $35,000 [10] in fines.

The agency has not yet penalized Petro Harvester for the July spill, thought it has issued a notice of violation and could impose a fine in the future, Roberts said, one of several spill-related enforcement actions the agency is considering.

Derrick Braaten, a Bismarck lawyer whose firm represents dozens of farmers and landowner groups, said his clients often get little support from regulators when oil companies damage their property.

State officials step in in the largest cases, he said, but let smaller ones slide. Landowners can sue, but most prefer to take whatever drillers offer rather than taking their chances in court.

"The oil company will say, that's worth $400 an acre, so here's $400 for ruining that acre," Braaten said.

Daryl Peterson, a client of Braaten's who is not related to Darwin Peterson, said a series of drilling waste releases stretching back 15 years have rendered several acres unusable of the 2,000 or so he farms. The state has not compelled the companies that caused the damage to repair it, he said. Peterson hasn't wanted to spend the hundreds of thousands of dollars it would take to haul out the dirt and replace it, so the land lies fallow.

"I pay taxes on that land," he said.

At least 15 North Dakota residents, frustrated with state officials' inaction, have taken drilling-related complaints to the U.S.

Environmental Protection Agency [11] in the last two years, records show.

Last September, for example, a rancher near Williston told the EPA that Brigham Oil and Gas had plowed through the side of a waste pit [12], sending fluid into the pond his cattle drink from and a nearby creek. When the rancher called Brigham to complain, he said, an employee told him this was "the way they do business."

A spokeswoman for Statoil, which acquired Brigham, said the company stores only fresh water in open pits, not wastewater, and that "we can't remember ever having responded in such a manner" to a report about a spill.

Federal officials can offer little relief.

Congress has largely delegated oversight of oil field spills to the states. EPA spokesman Richard Mylott said the agency investigates complaints about releases on federal lands, but refers complaints involving private property to state regulators.

The EPA handed the complaint about Brigham to an official with North Dakota's Health Department, who said he had already spoken to the company.

"They said this was an isolated occurrence, this is not how they handle frac water and it would not happen again," the official wrote to the EPA [12]. "As far as we are concerned, this complaint is closed."

Salting the Earth

Six years ago, a four-inch saltwater pipeline ruptured just outside Linda Monson's property line [13], leaking about a million gallons of salty wastewater.

As it cascaded down a hill and into Charbonneau Creek, which cuts through Monson's pasture, the spill deposited metals and carcinogenic hydrocarbons in the soil. The toxic brew wiped out the creek's fish, turtles and other life, reaching 15 miles downstream [14].

After suing Zenergy Inc., the oil company that owns the line, Monson reached a settlement that restricts what she can say about the incident.

"When this first happened, it pretty much consumed my life," Monson said. "Now I don't even want to think about it."

The company has paid a $70,000 fine [15] and committed to cleaning the site, but the case shows how difficult the cleanup can be. When brine leaks into the ground, the sodium binds to the soil, displacing other minerals and inhibiting plants' ability to absorb nutrients and water. Short of replacing the soil, the best option is to try to speed the natural flushing of the system, which can take decades.

Zenergy has tried both. According to a Department of Mineral Resources report, the company has spent more than $3 million hauling away dirt and pumping out contaminated groundwater [16] — nearly 31 million gallons as of December 2010, the most recent data available.

But more than a dozen acres of Monson's pasture remain fenced off and out of use. The cattle no longer drink from the creek, which was their main water source. Zenergy dug a well to replace it.

Shallow groundwater in the area remains thousands of times saltier than it should be [17] and continues to leak into the stream and through the ground, contaminating new areas.

There's little understanding of what long-term impacts hundreds of such releases could be having on western North Dakota's land and water, said Micah Reuber.

Until last year, Reuber was the environmental contaminant specialist in North Dakota for the federal Fish and Wildlife Service, which oversees wetlands and waterways.

Reuber quit after growing increasingly frustrated with the inadequate resources devoted to the position.

Responding to oil field spills was supposed to be a small part of his job, but it came to consume all of his time.

"It didn't seem like we were keeping pace with it at all," he said. "It got to be demoralizing."

Reuber said no agency, federal or state, has the money or staff to study the effects of drilling waste releases in North Dakota. The closest thing is a small ongoing federal study across the border in Montana, where scientists are investigating how decades of oil production have affected the underground water supply for the city of Poplar [18].

Joanna Thamke, a groundwater specialist with the U.S. Geological Survey in Montana, started mapping contamination from drilling 20 years ago. She estimated it had spread through about 12 square miles of the aquifer, which is the only source of drinking water in the area.

Over the years, brine had leaked through old well bores, buried waste pits and aging tanks and pipes.

In the Poplar study and others, Thamke has found that plumes of contaminated groundwater can take decades to dissipate and sometimes move to new areas.

"What we found is the plumes, after two decades, have not gone away," she said. "They've spread out."

Poplar's water supply is currently safe to drink, but the EPA has said it will become too salty as the contamination spreads. In March, the agency ordered three oil companies to treat the water or to find another source [19].

North Dakota officials are quick to point out that oversight and regulations are stronger today than they were when drilling began in the area in the 1950s. One significant difference is that waste pits, where oil companies store and dispose of the rock and debris produced during drilling, are now lined with plastic to prevent leaching into the ground.

New rules, effective April 1, require drillers in North Dakota to divert liquid waste to tanks instead of pits [3]. Until now, drillers could store the liquid in pits for up to a year before pumping it out in order to bury the solids on site. The rule would prevent a repeat of the spring of 2011, when record snowmelt and flooding caused dozens of pits to overflow their banks.

But Reuber worries that the industry and regulators are repeating past mistakes. Not long before he left the Fish and Wildlife Service, he found a set of old slides showing waste pits and spills from decades ago.

"They looked almost exactly like photos I had taken," he said. "There's a spill into a creek bottom in the Badlands and it was sitting there with no one cleaning it up and containing it. And yeah, I got a photo like that, too."

Keller has grown so dispirited by the changes brought by the boom that he is considering retiring after 30 years with the Army Corps and moving away from Williston. He runs a side business in scrap metal that would supplement his pension.

Still, determined to protect the area, he keeps alerting regulators whenever he spots evidence that oil companies have dumped or spilled waste.

Last July, when he saw signs of a spill near his home, Keller notified the Department of Mineral Resources and sent pictures showing a trail [20] of dead [21] grass [22] to an acquaintance at the EPA regional office in Denver. The brown swath led from a well site into a creek.

If the spills continued, he warned the EPA in an email [23], they could "kill off the entire watershed."

EPA officials said they spoke with Keller, but did not follow up on the incident beyond that. The state never responded, Keller said. The site remained untested and was never cleaned up.

"There was no restoration work whatsoever," Keller said.

Correction: This story stated that Department of Mineral Resources spokeswoman Alison Ritter could not say how many of the 45 enforcement actions taken by the agency over the last three years were for spills or releases, as opposed to other drilling violations, or how many resulted in fines. It should have added that Ritter said case files containing this information could be reviewed, but only in person in the agency's office in Bismarck, N.D. The story also said that, last July, when Jeff Keller saw signs of a spill near his home, he notified the Health Department. He notified the Department of Mineral Resources.

Update: North Dakota Department of Mineral Resources spokeswoman Alison Ritter submitted the following statement in response to this story yesterday (we have added editor's notes where appropriate for accuracy): The remarkable growth in western North Dakota's oil and gas industry has created great benefits and opportunities for our state, and significant challenges as well.

> The state is committed to protecting the environment and to meeting other impacts created by rapid energy development. As part of that commitment, the state Department of Mineral Resources has added staff for greater oversight and the North Dakota
>
> Industrial Commission has strengthened the state's oil and gas regulations to provide greater environmental protections than ever before. The rule changes, which took effect April 1, ban the use of open pits; increased bond requirements, strengthen hydraulic fracturing requirements and mandate the reporting of chemicals used in the hydraulic fracturing process. A two-part news report prepared by New York-based ProPublica and published by the Forum of Fargo-Moorhead on June 10 and 11 included several errors of fact about the state's role in regulating the oil industry.

1. In the report, Nicholas Kusnetz reported that Oklahoma has comparable drilling activity, but employs 58 inspectors to North Dakota's 19. What Kusnetz failed to tell readers is that Oklahoma has about 90,000 active wells while North Dakota has less than 7,000 wells, and that well sites – not drilling sites – pose the greatest risk of accidental spills. About 95 percent of spills occur at well sites as opposed to drilling sites.
2. Mr. Kusnetz reported that the Department of Mineral Resources could not provide details regarding rule violations that led to 45 enforcement actions against oil companies. The fact is that Mr. Kusnetz was invited to visit the Department of Mineral Resources where he could review each case file for the information he sought, but he chose not to. Editor's note: We have updated the article to reflect this information.
3. Mr. Kusnetz reported that the state has issued only 45 disciplinary actions in the last three years for drilling violations, but what he failed to tell readers is that approximately

99% of all violations have been remedied by the state requiring companies to clean up their spills in an effective and timely manner.

4. Mr. Kusnetz reported that state officials rely on companies to clean up spills voluntarily. North Dakota law mandates that companies clean up spills and no officials from the Department of Mineral Resources suggested otherwise. All spill sites are inspected and enforcement actions are taken when companies fail to clean spills in an effective and timely manner.
5. Mr. Kusnetz reported that Jeff Keller, a natural resource manager for the U.S. Army Corps of Engineers, has observed trucks illegally dumping wastewater and that Keller also has spotted a spill. Mr. Keller and the U.S. Army Corps of Engineers have never filed a spill report with the Department of Mineral Resources. Editor's note: Keller said he reported a spill to the Department of Mineral Resources as well as reporting other incidents to the Health Department.
6. Mr. Kusnetz reported that "Congress has largely delegated oversight of oil field spills to the states." The EPA operates the Spill Prevention, Control, and Countermeasure program, and under federal law cannot delegate any part of this program to state enforcement agencies. State enforcement of the oil industry goes above and beyond federal enforcement.
7. Mr. Kusnetz reported two-thirds of spills were not contained. Data compiled by the Department of Mineral Resources shows that about 30 percent - less than one-third - of all spills were not immediately contained. Editor's note: This is not an accurate paraphrasing of the story, which said that in about two-thirds of the cases, spills were not contained "to the accident site."
8. Official records do not support Mr. Kusnetz's statement that state regulators "have been unable - or unwilling - to compel companies to clean up their mess." The state Department of Health utilizes its authority to impose a variety of sanctions to protect the environment, including but not limited to monetary penalties. Most reported spills have been addressed through the completion of onsite inspections and state-mandated remediation. Editor's note: This is not an accurate quote from the story,
    1. which says "state regulators have often been unable — or unwilling — to compel energy companies to clean up their mess."
9. While most oilfield waste water is properly disposed of in Class II wells, the state Department of Health acknowledges that some illegal disposal does take place. Catching

companies or individuals engaged in illegal dumping is difficult. However, the department is increasing its enforcement presence with additional inspectors and modifying its regulations to increase civil penalties.

10. Mr. Kusnetz reported that “the state has no real estimate of the quantity of fluids spilled from tanks, pipe, trucks and other equipment.” The state Department of Health evaluates each spill on a case-by-case basis to determine the specific issues associated with each spill. State records show that more than 70 percent of the spills have involved fluid amounts of 10 barrels or less.

It's important that the people of North Dakota receive factual information as we work together to protect our land, water and air and to support the responsible development of our energy resources.

Lynn Helms, Director, North Dakota Department of Mineral Resources Dave Glatt, Environmental Health Section Chief, North Dakota Department of Health

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2. #nd-update
3. http://m.washingtonexaminer.com/rules-approved-to-cut-north-dakota-oil-waste-pits/
4. http://bismarcktribune.com/news/state-and-regional/north-dakota-grasslands-oil-and-gas-projects-expedited/article_c86cb2d0-f420-11e0-8d53-001cc4c03286.html
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7. http://www.propublica.org/special/north-dakota-spills
8. http://www.propublica.org/documents/item/329880-cramer-spill-report.html
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15. http://www.propublica.org/documents/item/329883-health-department-administrative-complaints.html#document/p40
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23. http://www.propublica.org/documents/item/329875-second-email-from-jeff-keller-to-epa.html

4.11 2012-07-09 _ New Study: Fluids from Marcellus Shale Likely Seeping Into PA Drinking Water

A drilling site in South Montrose, Pa. (Spencer Platt/Getty Images)

by Abrahm Lustgarten *ProPublica, July 9, 2012, 1 p.m.*

New research has concluded that salty, mineral-rich fluids deep beneath Pennsylvania's natural gas fields are likely seeping upward thousands of feet into drinking water supplies.

Though the fluids were natural and not the byproduct of drilling or hydraulic fracturing, the finding further stokes the red-hot controversy over fracking in the Marcellus Shale, suggesting that drilling waste and chemicals could migrate in ways previously thought to be impossible.

The study, conducted by scientists at Duke University and California State Polytechnic University at Pomona and released today in the Proceedings of the National Academy of Sciences [1], tested drinking water wells and aquifers across Northeastern Pennsylvania.

Researchers found that, in some cases, the water had mixed with brine that closely matched brine thought to be from the Marcellus Shale or areas close to it.

No drilling chemicals were detected in the water, and there was no correlation between where the natural brine was detected and where drilling takes place.

Still, the brine's presence – and the finding that it moved over thousands of vertical feet -- contradicts the oft-repeated notion that deeply buried rock layers will always seal in material injected underground through drilling, mining, or underground disposal.

"The biggest implication is the apparent presence of connections from deep underground to the surface," said Robert Jackson, a biology professor at the Nicholas School of the Environment at Duke University and one of the study's authors. "It's a suggestion based on good evidence that there are places that may be more at risk."

The study is the second in recent months to find that the geology surrounding the Marcellus Shale could allow contaminants to move more freely than expected. A paper published [2] by the journal Ground Water [3] in April used modeling to predict that contaminants could reach the surface within 100 years – or fewer if the ground is fracked.

Last year, some of the same Duke researchers [4] found that methane gas was far more [5] likely to leak into water supplies in places adjacent to drilling.

Today's research swiftly drew criticism from both the oil and gas industry and a scientist on the National Academy of Science's peer review panel. They called the science flawed, in part because the researchers do not know how long it may have taken for the brine to leak. The National Academy of Sciences should not have published the article without an accompanying rebuttal, they said.

"What you have here is another case of a paper whose actual findings are pretty benign, but one that, in the current environment, may be vulnerable to distortion among those who oppose this industry," said Chris Tucker, a spokesman for the gas industry trade group Energy In Depth. "What's controversial is attempting to argue that these migrations occur as a result of industry activities, and on a time scale that actually matters to humanity."

Another critic, Penn State University geologist Terry Engelder, took the unusual step of disclosing details of his review of the paper for the National Academy of Sciences, normally a private process.

In a letter written to the researchers [6] and provided to ProPublica, Engelder said the study had the appearance of "science-based advocacy" and said it was "unwittingly written to enflame the anti-drilling crowd."

In emails, Engelder told ProPublica that he did not dispute the basic premise of the article – that fluids seemed to have migrated thousands of feet upward. But he said that they had likely come from even deeper than the Marcellus – a layer 15,000 feet below the surface – and that there was no research to determine what pathways the fluids travelled or how long they took to migrate. He also said the Marcellus was an unlikely source of the brine because it does not contain much water.

"There is a question of time scale and what length of time matters," Engelder wrote in his review. In a subsequent letter to the Academy's editors [7] protesting the study, he wrote that "the implication is that the Marcellus is leaking now, naturally without any human assistance, and that if water-based fluid is injected into these cross-formational pathways, that leakage, which is already 'contaminating' the aquifers with salt, could be made much worse."

Indeed, while the study did not explicitly focus on fracking, the article acknowledged the implications. "The coincidence of elevated salinity in shallow groundwater... suggests that these areas could be at greater risk of contamination from shale gas development because of a preexisting network of cross-formational pathways that has enhanced hydraulic connectivity to deeper geological formations," the paper states.

For their research, the scientists collected 426 recent and historical water samples -- combining their own testing with government records from the 1980s -- from shallow water wells and analyzed them for brine, comparing their chemical makeup to that of 83 brine samples unearthed as waste water from drilling sites in the Marcellus Shale.

Nearly one out of six recent water samples contained brine near-identical to Marcellus-layer brine water.

Nevertheless, Jackson, one of the study's authors, said he still considers it unlikely that frack fluids and injected man-made waste are migrating into drinking water supplies. If that were happening, those contaminants would be more likely to appear in his groundwater samples, he said. His group is continuing its research into how the natural brine might have travelled, and how long it took to rise to the surface.

"There is a real time uncertainty," he said. "We don't know if this happens over a couple of years, or over millennia."

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2. http://www.propublica.org/article/new-study-predicts-frack-fluids-can-migrate-to-aquifers-within-years
3. http://onlinelibrary.wiley.com/doi/10.1111/j.1745-6584.2012.00933.x/abstract
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4.12 2013-02-04 _ Update: State Oil and Gas Regulators Still Spread Thin

(Abrahm Lustgarten/ProPublica)

by Abrahm Lustgarten *ProPublica, Feb. 4, 2013, 3:57 p.m.*

The U.S. relies on state and federal regulators to make sure that oil and gas drilling is done safely, and that trillions of gallons of toxic waste injected [1] into underground disposal wells do not contaminate [2] water supplies.

Today, ProPublica is updating its database [3] on oversight of production and waste wells, adding records for 2010 and 2011 — the most recent year available for many states — to data from 2003 to 2009. We've added information about agencies' budgets, as well as the total number of injection wells they are responsible for overseeing.

The data shows some states have hired more inspectors or otherwise increased their enforcement capacity.

Still, the ratio of wells to inspectors remains extremely high, and the volume of waste being pumped underground has ballooned, driven in large part to the boom in drilling made possible by fracking.

Over a five-year span, ProPublica has investigated the risks from fracking [4] and the expanding system of underground injection wells [5], often finding that regulatory agencies have fallen short in enforcing critical environmental protections.

In 2009, we found that the state oil and gas agencies charged with overseeing fracking and the drilling of natural gas were often woefully understaffed [6], just as the largest drilling boom in the recent history was ramping up.

In 2012, we investigated how the same agencies and the federal government were monitoring roughly 700,000 underground disposal wells [1] in the U.S., of which more than 150,000 are used for waste from oil and gas drilling.

Our examination of records summarizing more than 220,000 well inspections conducted between late 2007 and late 2010 showed that fundamental safeguards are sometimes ignored or circumvented. We found records showing that more than 7,000 wells had leaked, and that more than 17,000 wells had failed structural tests [1].

Because of a lack of regulatory resources, our reporting showed, disposal wells often don't get the oversight that they need.

According to our September report [2]:

> State and federal regulators often do little to confirm what pollutants go into wells for drilling waste. They rely heavily on an honor system in which companies are supposed to report what they are pumping into the earth, whether their wells are structurally sound, and whether they have violated any rules.
>
> More than 1,000 times in the three-year period examined, operators pumped waste into Class 2 wells at pressure levels they knew could fracture rock and lead to leaks. In at least 140 cases, companies injected waste illegally or without a permit.

In several instances, records show, operators did not meet requirements to identify old or abandoned wells near injection sites until waste flooded back up to the surface, or found ways to cheat on tests meant to make sure wells aren't leaking.

1. http://www.propublica.org/article/injection-wells-the-poison-beneath-us
2. http://www.propublica.org/article/trillion-gallon-loophole-lax-rules-for-drillers-that-inject-pollutants
3. http://projects.propublica.org/gas-drilling/
4. http://www.propublica.org/series/fracking
5. http://www.propublica.org/series/injection-wells
6. http://www.propublica.org/article/state-oil-and-gas-regulators-are-spread-too-thin-to-do-their-jobs-1230

4.13 2013-02-23 _ Land Grab Cheats North Dakota Tribes Out of $1 Billion, Suits Allege

Fort Berthold in North Dakota (Abrahm Lustgarten/ProPublica)

by Abrahm Lustgarten *ProPublica, Feb. 23, 2013, 8:59 p.m.*

Native Americans on an oil-rich North Dakota reservation have been cheated out of more than $1 billion by schemes to buy drilling rights for lowball prices, a flurry of recent lawsuits assert. And, the suits claim, the federal government facilitated the alleged swindle by failing in its legal obligation to ensure the tribes got a fair deal.

This is a story as old as America itself, given a new twist by fracking and the boom that technology has sparked in North Dakota oil country. Since the late 1800s, the U.S. government has appropriated much of the original tribal lands associated with the Fort Berthold reservation in North Dakota for railroads and white homesteaders. A devastating blow was delivered when the Army Corps of Engineers dammed the Missouri River in 1953, flooding more than 150,000 acres at the heart of the remaining reservation.

Members of the Three Affiliated Tribes — the Mandan, Hidatsa and Arikara — were forced out of the fertile valley and up into the arid and barren surrounding hills, where they live now.

But that last-resort land turns out to hold a wealth of oil, because it sits on the Bakken Shale, widely believed to be one of the world's largest deposits of crude. Until recently, that oil was difficult to extract, but hydraulic fracturing, combined with the ability to drill a well sideways underground, can tap it. The result, according to several senior tribal members and lawsuits filed last November and early this year in federal and state courts, has been a land grab involving everyone from tribal leaders accused of enriching themselves at the expense of their people, to oil speculators, to a New York hedge fund, to the federal government's Bureau of Indian Affairs.

The rush to get access to oil on tribal lands is part of the oil industry's larger push to secure drilling rights across the United States. Recent estimates show that the U.S. contains vast quantities of oil and gas. As fracking has opened new fields to drilling, and the U.S. has striven to get more of its energy from within its borders, leases from Louisiana to Pennsylvania have been gobbled up. Now the pressure is increasing on one of the last sizeable holdouts — lands owned by Native Americans.

A review of tribal and federal records as well as lawsuit documents reveals a dizzying array of lowball, non-competitive deals brokered by numerous companies, often entwined with the tribal council and with individual landholders on the reservation. But at heart the alleged practices are simple: Tribal leaders and outsiders set up companies to buy drilling rights cheap and flip them later for spectacular profits — in one case earning as much as a 200-fold return in just four years.

"Hundreds of millions of dollars were lost," said Tex Hall, the current chairman of the Three Affiliated Tribes, in an interview. "It's just a huge loss and we'll never get it back."

At the center of that particular alleged scheme, according to one of the suits, was Spencer Wilkinson, Jr., longtime manager of 4 Bears Casino, a time-worn warehouse of slot machines, swirling cigarette smoke and stained carpets that serves as the reservation's entertainment nexus and its financial hub. Wilkinson also sat on the board of the tribe's development corporation, where he was charged with finding new opportunities to enhance the economy of the reservation.

According to interviews with tribal members, former employees of the Three Affiliated Tribes, and a class action lawsuit filed in federal district court in Bismarck, ND against Wilkinson and others, Wilkinson used his access to casino funds — and to the development corporation — to gain influence and craft an oil deal that would leave him one of the richest men on the reservation.

In 2006 he became an owner of a company, Dakota-3, with Richard Woodward, a white consultant who, records show, was receiving more than $20,000 a month from tribal funds for his work at the development corporation. Together, the suit and other legal filings allege, Wilkinson and Woodward planned to raise money and buy up rights to much of the remaining land not yet slated for drilling, all the while maintaining their work with the tribes and employing Wilkinson's relationship with the council to help get the oil leases approved.

Leases for oil rights generally work like this: A company purchases the right to drill for oil underneath an acre of land by paying a one-time upfront payment, called a bonus, and a percentage of the profits earned on the well, known as a royalty. On Indian lands additional laws also apply, dictating who can negotiate for whom and how the government has to oversee the agreements.

Wilkinson declined to comment and Woodward could not be reached. Wilkinson has filed a motion to dismiss the case. The suit alleges that Wilkinson and others aided and abetted the U.S. government in failing to fulfill its fiduciary responsibility to the tribes; Wilkinson's motion argues, among other things, that the government had no such responsibility. Woodward has not yet filed a response to the suit in court.

Many details of Dakota-3's deals remain murky. There is limited transparency into tribal government affairs, no public access to documents, no annual reporting on accounts, and limited communication about what tribal council members discuss in their meetings.

But, according to separate lawsuits and records filed with the North Dakota Secretary of State, Dakota-3 partnered with an Oklahomabased oil speculator named Robert Zinke and his company Zenergy to buy leases and form additional joint venture companies. Documents from two law suits mention the involvement of the New York based hedge fund Och-Ziff Capital Management Group but do not specify the firm's role. The hedge fund is publicly traded and, according to its web site, has more than $33 billion under management.

A spokesman for Och-Ziff declined to comment, and Zinke did not return a telephone message.

The interlinked companies, the documents show, purchased drilling rights to some 42,500 acres of lands owned by individuals and families through dozens of separate small deals. Those rights were ultimately controlled by Dakota-3, which also purchased from the tribal council drilling rights to another 44,000 acres of lands managed by the council. Altogether, Dakota-3 accumulated rights to about a fifth of the 420,000-odd acres of leasable land on the reservation, having bought much of those rights for as little as $50 per acre and royalties of around 18 percent. At about the same time, records and interviews show, other companies were purchasing drilling rights to land on and near the reservation for $300 to $1,000 per acre plus royalties as high as 22.5 percent.

One of the lawsuits alleges that the difference in the one-time bonus payments, plus the difference in royalty payments, "could mean billions of dollars" over the life of the oil field.

In late 2010, an Oklahoma-based oil production company, Williams, bought Dakota-3 for $925 million. At the time of the purchase, Dakota-3 was pumping a small amount of oil, but the bulk of its assets were the drilling rights. Two lawsuits allege that by buying Dakota- 3, Williams effectively paid more than $10,000 per acre for those rights — as much as 200 times what Dakota-3 had paid for the leases.

At issue is not just the question of how Dakota-3 managed to win the tribal council's approval for the deal, but whether the federal government should have stepped in to ensure that the tribes were paid higher rates.

Reservation lands are still held in trust by the U.S. government. As a trustee, the Department of the Interior has responsibility for overseeing the development of oil and gas on tribal lands, and for ensuring that any leases or sales of that land are made in "the best interest" of the Native Americans. When it comes to leases to drill for oil — even those negotiated directly between the tribal council and the oil industry — the Bureau of Indian Affairs is required to make sure the leases meet this standard.

The bureau did not respond to a list of written questions, but according to interviews and documents obtained by ProPublica, the bureau approved the leases even though some Interior Department staffers expressed misgivings. Other documents show that tribal members appealed to high-level Interior Department officials and others to reject the leases and step in on their behalf.

"Mr. Secretary, this company, Dakota-3, like the other companies in the oil business will turn around and sell the lease," wrote Russell Mason Sr., a tribal elder, to the Assistant Secretary for Indian Affairs in a December, 2007 letter. "We are making a plea to you that you exercise your trust responsibilities."

"The United States has uniformly failed in its duties to the Indian landowners," states one lawsuit in the U.S. Court of Federal Claims in Washington, D.C. that was brought by tribal landowners seeking restitution for the Dakota-3 leases sold to Williams.

The Dakota-3 deals are not the only controversial ones. For example, a company called Black Rock Resources purchased drilling rights to about 12,800 acres of land for $35 per acre and a 16.7 percent royalty. It later sold those rights to Marathon Oil for about $42 million, according to financial documents that describe the deal.

Messages left for multiple Black Rock Resources officials were not returned, and Marathon Oil did not immediately respond to a message seeking comment.

The Bureau of Indian Affairs approved the Black Rock deal, and documents obtained by ProPublica reveal the sometimes-contradictory advice the Bureau of Indian Affairs received from its own staff and other federal officials.

When Black Rock first offered to buy up reservation leases for $35 per acre beginning in 2005, some bureau staff justified the rates saying the cumbersome regulations and past problems with leasing on the reservation had driven down demand. "Unfortunately," wrote one staffer in a department letter, $35 per acre "is what the market will bear."

But in a review dated November, 2005, an expert at the Bureau of Land Management wrote that the offered price "appears to look low compared to those offered recently at both BLM and North Dakota State competitive oil and gas lease sales in the area." He cited other sales that same month for as much as $370 an acre. An Interior Department lawyer in Washington sent a letter to North Dakota BIA officials expressing similar concerns.

Even at the time, the tribe received higher offers. Jerry Nagel is a tribe member, businessman and former program analyst for the tribe who has been outspoken against leases he thought were being sold for too little. In an interview, he said that he financed a venture in 2006 that offered the tribe $140 per acre plus a royalty rate more than twice as high as the tribal council was offered for the big leases it ultimately signed. It's unclear why the tribal council didn't take that offer, but Nagel claims it's evidence that the council gave preferential treatment to certain suitors.

The tribal council's office did not immediately respond to questions about why the council passed over Nagel's offer.

Kyle Baker is a tribe member, geologist and former environment official for minerals and energy for the tribe. He said that his family struck deals to lease its acreage on and near the reservation for as much as $700 per acre around the same time as the Black Rock deal.

"Companies will come and find your weaknesses and then drive themselves in," Baker said on a recent wintery morning in his living room overlooking Lake Sakakawea. "Our laws, our setup wasn't ready for it." Companies and the U.S. government have long known that the Ft. Berthold reservation lay in the heart of the oil-rich Williston Basin, a reserve thought by some to contain as much as 20 billion barrels of oil. But previous efforts to lease and drill on the Indian lands stalled in the 1970s, and again in the late 1990s, thwarted by a dense bureaucracy and a tangle of laws governing leasing on reservations.

Only after the advent of modern fracking — and after Congress passed a handful of laws to ease corporate access to the Ft Berthold reservation — did companies begin to invest seriously in drilling there.

Today it's estimated that the three tribes and individual Native American landholders are receiving some $50 to $80 million a year from the drilling leases and royalties, compared with revenues of about $5 million a year before the boom began in about 2006.

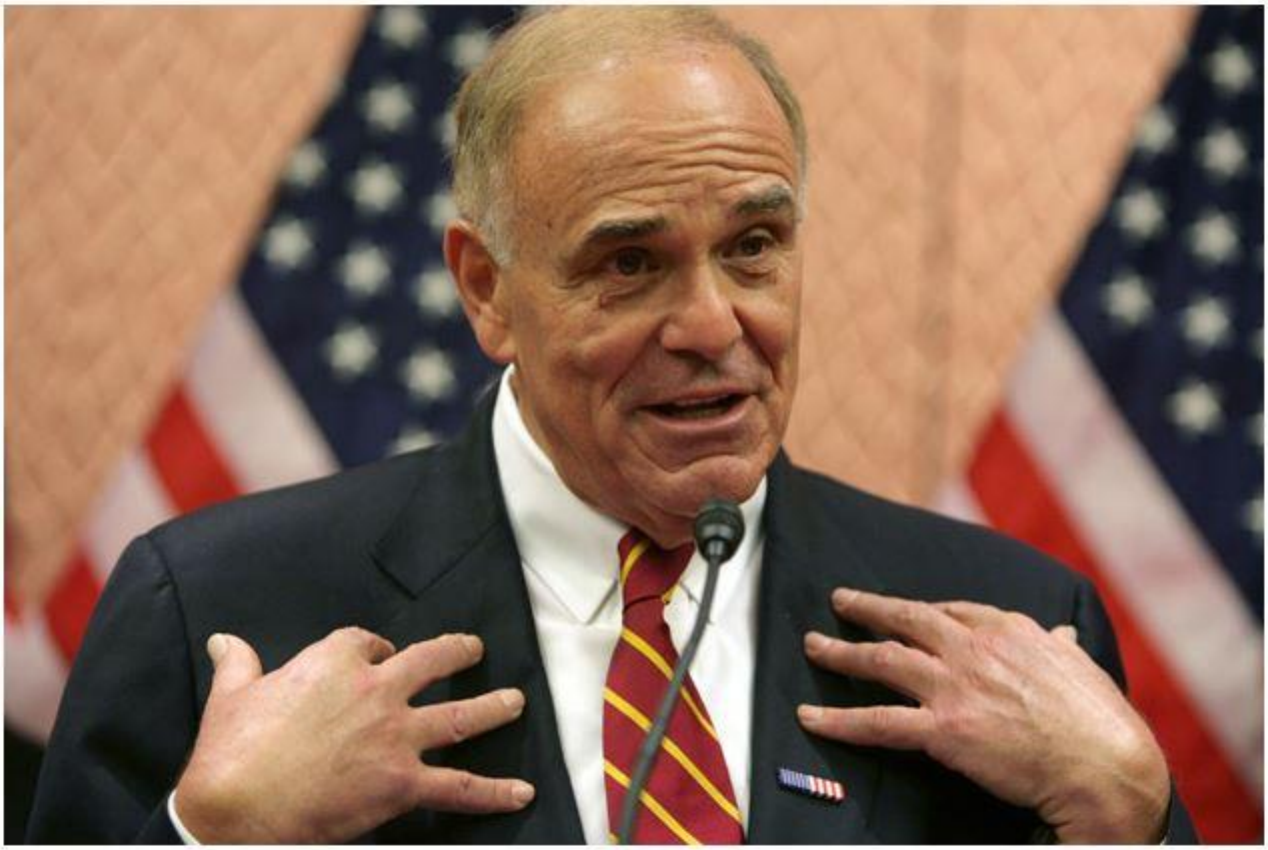
But that money has brought allegations of sweetheart arrangements that have left a few tribal members with disproportionate profits from oil development.

In 2011 a team of elders audited the tribal council's activities. They found widespread financial inconsistencies that they said indicated systemic misconduct. "We saw millions of dollars going out and hardly anything coming back" to the Three Affiliated Tribes, said Tony Foote a forensic auditor who chaired the team. "We're not just talking about cash. It's rooms, food, travel, donations, and there's only a handful of people that can get all this stuff."

Hall, the tribes' current chairman, had previously held that post from 1998 until 2006. He didn't deny that there had been corruption, but he said that since he came back into office in 2010 he has focused on reform and on making sure that the oil revenues benefit the broader tribal community. He said he has formed tribal entities to directly control a pipeline and refinery project, set up a $100 million trust fund for the tribes, and begun to sign lease agreements that are more favorable to the Native Americans on the reservation. He also demoted Wilkinson, who is now an administrative officer at the casino, not its CEO.

"I was called back because people were concerned about sweetheart deals, so we have totally changed the dynamic," he said.

4.14 2013-03-28 _ More Than a Matter of Opinion: Ed Rendell's Plea for Fracking Fails to Disclose Industry Ties



Former Pennsylvania Gov. Ed Rendell (Chris Kleponis/Getty Images)

by Justin Elliott *ProPublica, March 28, 2013, 11:28 a.m.*

Former Pennsylvania Gov. Ed Rendell took to the New York Daily News op-ed page [1] Wednesday with a message to local officials: stop worrying and learn to love fracking.

As New York Gov. Andrew Cuomo agonizes [2] over whether to allow the controversial natural gas drilling technique, Rendell invoked his own experience as a Democratic governor who presided over a fracking boom. New York state, Rendell argued, has a major part to play in the nation's fracking "revolution" — and it can do so safely. He rejected what he called the "false choice" of "natural gas versus the environment."

What Rendell's passionate plea failed to note was this: since stepping down as governor in 2011, he has worked as a paid consultant to a private equity firm with investments in the natural gas industry.
The op-ed piece was widely [3] noted [4] in [5] other media outlets, and Cuomo wound up being asked [5] about it during a radio appearance on Wednesday. The New York State Petroleum Council promptly issued a press release [6] hailing Rendell's "strong and confident argument."

Reached Wednesday, Rendell told ProPublica that he should have disclosed to the Daily News his work at [7] the private equity firm, Element Partners, and that the newspaper "should have included it."
Rendell said the Pennsylvania-based firm pays him about $30,000 per year. Still, he insisted he is not conflicted on the issue of fracking, in which water and chemicals are injected [8] deep into the ground to extract previously unreachable natural gas from rock. He said he does not own equity in Element Partners or any fracking companies.

"The only conflict would be if I had a pecuniary interest in the natural gas industry doing well, and I certainly don't," he said. Element Partners' website lists [9] several investments by the firm in natural gas companies, including a company called 212 Resources [9] that specializes in "fluid management systems" for fracking.
Rendell is also a senior adviser [10] at the investment bank Greenhill, which has worked on several large transactions [11] involving natural gas companies. A Greenhill spokesman said Rendell has not been involved in the firm's work in the energy sector.

"I have no brief for industry," Rendell told ProPublica. He said he supports fracking because of the potential for American energy independence and jobs.

"If we choose to embrace natural gas, it will help us get past a number of significant economic and environmental challenges," Rendell argued in the Daily News op-ed. "On the other hand, if we let fear carry the day, we will squander another key moment to move forward together."

Daily News opinion editor Josh Greenman said in an email to ProPublica that he was unaware of Rendell's relationship with Element, and indeed had been assured by Rendell's representative that there was no conflict.

“Had I known, I certainly would have disclosed that and conceivably would have made a different judgment on the piece," Greenman said.

The Daily News has now added [1] a disclosure line to the online version of the op-ed.

This isn’t the first time Rendell has popped up in New York advocating for fracking. The New York Post ran an interview [12] with Rendell in November in which he said Cuomo would be “crazy” not to lift the fracking ban. That piece didn’t mention Rendell’s ties to the industry either.

Update 4:15 pm: It’s worth noting that since leaving office, Rendell has been a vocal supporter of fracking around the country. He’s weighed in in support of a regulated fracking industry in venues including Huffington Post [13]; the Nightly Business Report [14]; a Manhattan Institute [15] forum; the Austin, Texas, PBS affiliate [16]; and a Wall Street Journal conference [17] with businessman T. Boone Pickens.

Update 4/8/13: There's another layer to Rendell's fracking connections [18] -- his law firm.

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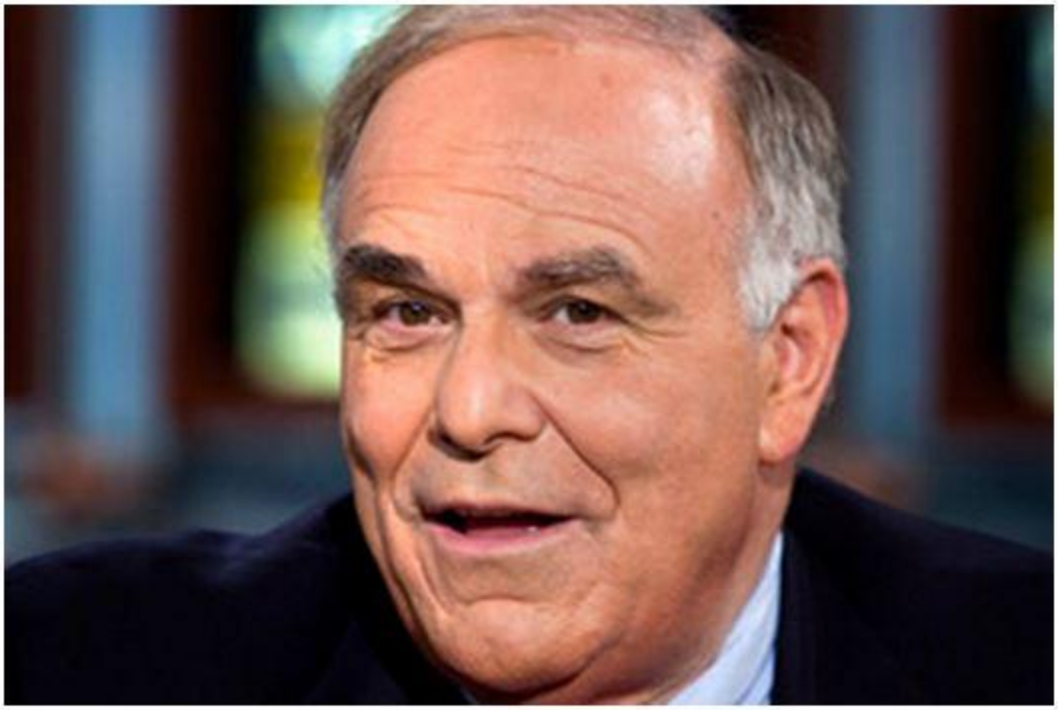
4.15 2013-04-08 _ Another Layer to Rendell's Fracking Connections



by Justin Elliott *ProPublica, April 8, 2013, 2:29 p.m.*

Recently, we wrote about former Pennsylvania Gov. Ed Rendell's connections to the natural gas industry [1] after he published a pro-fracking op-ed in The New York Daily News.

Following our story, Rendell's column [2] — which called on New York officials to lift a ban on the drilling technique — was updated to disclose that he is a paid consultant to a private equity firm with natural gas investments.

Rendell assured us in an interview before the first story that despite his role with the private equity firm, he had no "pecuniary interest in the natural gas industry doing well."

But the story doesn't end there. One entity that indisputably has an interest in the industry is Rendell's longtime home outside of politics: the law firm Ballard Spahr of Philadelphia.

Rendell is currently special counsel at the firm, and is a member of its energy and project finance [3] and environment and natural resources [4] practice areas, his spokeswoman said.

The firm touts its work "on the forefront" of the development of the Marcellus Shale, the formation under Pennsylvania and other states from which a vast quantity of natural gas is now being extracted.

In 2011, the publication AOL Energy named [5] Ballard Spahr one of the top five energy law firms in the country. AOL cited Ballard Spahr's "deep presence in Pennsylvania" that "put it on the doorstep of the Marcellus Shale natural gas field," a "major source of controversy and legal work as developers work in heavily populated and closely monitored areas."

A week after leaving the governor's office in 2011, Rendell rejoined [6] the firm, where he had given up his job as partner when he was elected in 2003. As governor, he presided over the fracking boom in Pennsylvania.

Has he worked for natural gas interests in his role [7] at Ballard Spahr?

"Governor Rendell cannot comment on what areas he may or may not work on for clients of the firm," Kirstin Snow, his spokeswoman, said in an email.

Another attorney in Ballard Spahr's Philadelphia office, Harry Weiss [8], has "advocated for an oil and gas company at both the state and federal levels during regulatory and policy debates on impact of shale gas exploration on ground water supplies," according to the firm. He also represents landowners in lease negotiations with gas companies.

The firm did not respond to a request for comment about Rendell's work.

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4.16 2013-07-03 _ EPA's Abandoned Wyoming Fracking Study One Retreat of Many

by Abrahm Lustgarten *ProPublica, July 3, 2013, 11:58 a.m.*

When the Environmental Protection Agency abruptly retreated on its multimillion-dollar investigation into water contamination in a central Wyoming natural gas field last month, it shocked environmentalists and energy industry supporters alike.

In 2011, the agency had issued a blockbuster draft report [1] saying that the controversial practice of fracking was to blame for the pollution of an aquifer deep below the town of Pavillion, Wy. – the first time such a claim had been based on a scientific analysis.

The study drew heated criticism over its methodology and awaited a peer review that promised to settle the dispute. Now the EPA will instead hand the study [2] over to the state of Wyoming, whose research will be funded by EnCana, the very drilling company whose wells may have caused the contamination.

Industry advocates say the EPA's turnabout reflects an overdue recognition that it had overreached on fracking and that its science was critically flawed.

But environmentalists see an agency that is systematically disengaging from any research that could be perceived as questioning the safety of fracking or oil drilling, even as President Obama lays out a plan to combat climate change that rests heavily on the use of natural gas.

Over the past 15 months, they point out, the EPA has:

- Closed an investigation into groundwater pollution in Dimock, Pa., saying the level of contamination was below federal safety triggers.
- Abandoned its claim that a driller in Parker County, Texas, was responsible for methane gas bubbling up in residents' faucets, even though a geologist hired by the agency confirmed this finding.
- Sharply revised downward a 2010 estimate showing that leaking gas from wells and pipelines was contributing to climate change,
- crediting better pollution controls by the drilling industry even as other reports indicate the leaks may be larger than previously thought.
- Failed to enforce a statutory ban on using diesel fuel in fracking.

“We’re seeing a pattern that is of great concern,” said Amy Mall, a senior policy analyst for the Natural Resources Defense Council in Washington. “They need to make sure that scientific investigations are thorough enough to ensure that the public is getting a full scientific explanation.”

The EPA says that the string of decisions is not related, and the Pavillion matter will be resolved more quickly by state officials. The agency has maintained publicly that it remains committed to an ongoing national study of hydraulic fracturing, which it says will draw the definitive line on fracking’s risks to water.

In private conversations, however, high-ranking agency officials acknowledge that fierce pressure from the drilling industry and its powerful allies on Capitol Hill – as well as financial constraints and a delicate policy balance sought by the White House -- is squelching their ability to scrutinize not only the effects of oil and gas drilling, but other environmental protections as well.

Last year, the agency’s budget was sliced 17 percent, to below 1998 levels. Sequestration forced further cuts, making research initiatives like the one in Pavillion harder to fund.

One reflection of the intense political spotlight on the agency: In May, Senate Republicans boycotted a vote on President Obama’s nominee to head the EPA, Gina McCarthy, after asking her to answer more than 1,000 questions on regulatory and policy concerns, including energy.

The Pavillion study touched a particular nerve for Sen. James Inhofe, R-Okla., the former ranking member of the Senate Environment and Public Works committee.

According to correspondence obtained under the Freedom of Information Act, Inhofe demanded repeated briefings from EPA officials on fracking initiatives and barraged the agency with questions on its expenditures in Pavillion, down to how many dollars it paid a lab to check water samples for a particular contaminant.

He also wrote a letter to the EPA’s top administrator calling a draft report that concluded fracking likely helped pollute Pavillion’s drinking water “unsubstantiated” and pillorying it as part of an “Administration-wide effort to hinder and unnecessarily regulate hydraulic fracturing on the federal level.” He called for the EPA’s inspector general to open an investigation into the agency’s actions related to fracking.

When the EPA announced it would end its research in Pavillion, Inhofe – whose office did not respond to questions from ProPublica – was quick to applaud.

“EPA thought it had a rock solid case linking groundwater contamination to hydraulic fracturing in Pavillion, WY, but we knew all along that the science was not there,” Inhofe said in a press release issued the day of the announcement.

Others, however, wonder whether a gun-shy EPA is capable of answering the pressing question of whether the nation’s natural gas boom will also bring a wave of environmental harm.

“The EPA has just put a ‘kick me’ sign on it,” John Hanger, a Democratic candidate for governor in Pennsylvania and the former secretary of the state’s Department of Environmental Protection, wrote on his blog [3] in response to the EPA news about Pavillion. “Its critics from all quarters will now oblige.” **

Before fracking became the subject of a high-stakes national debate, federal agencies appeared to be moving aggressively to study whether the drilling technique was connected to mounting complaints of water pollution and health problems near well sites nationwide.

As some states began to strengthen regulations for fracking, the federal government prepared to issue rules for how wells would be fracked on lands it directly controlled.

The EPA also launched prominent scientific studies in Texas, Wyoming and Pennsylvania, stepping into each case after residents voiced concerns that state environmental agencies had not properly examined problems.

The EPA probe in Pavillion began in 2008 with the aim of determining whether the town’s water was safe to drink. The area was first drilled in 1960 and had been the site of extensive natural gas development since the 1990’s. Starting at about the same time, residents had complained of physical ailments and said their drinking water was black and tasted of chemicals.

The EPA conducted four rounds of sampling [4], first testing the water from more than 40 homes and later drilling two deep wells to test water from layers of earth that chemicals from farming and old oil and gas waste pits were unlikely to reach.

The sampling revealed oil [5], methane, arsenic, and metals including copper and vanadium – as well as other compounds --in shallow water wells. It also detected a trace of an obscure compound linked to materials used in fracking, called 2-butoxyethanol phosphate (2- BEp).

The deep-well tests showed benzene [6], at 50 times the level that is considered safe for people, as well as phenols -- another dangerous human carcinogen -- acetone, toluene, naphthalene and traces of diesel fuel, which seemed to show that man-made pollutants had found their way deep into the cracks of the earth. In all, EPA detected 13 different compounds in the deep aquifer [1] that it said were often used with hydraulic fracturing processes, including 2-Butoxyethanol, a close relation to the 2-BEp found near the surface.[1] [7]

The agency issued a draft report in 2011 [6] stating that while some of the pollution in the shallow water wells was likely the result of seepage from old waste pits nearby, the array of chemicals found in the deep test wells was "the result of direct mixing of hydraulic fracturing fluids with ground water in the Pavillion gas field."

The report triggered a hailstorm of criticism [8] not only from the drilling industry, but from state oil and gas regulators, who disagreed with the EPA's interpretation of its data. They raised serious questions about the EPA's methodology [9] and the materials they used, postulating that contaminants found in deep-well samples could have been put there by the agency itself in the testing process.

In response, the EPA agreed to more testing [10] and repeatedly extended the comment period on its study, delaying the peer review process.

Agency officials insist their data was correct, but the EPA's decision to withdraw from Pavillion means the peer-review process won't go forward and the findings in the draft report will never become final.

"We stand by what our data said," an EPA spokesperson told ProPublica after the June 20 announcement, "but I do think there is a difference between data and conclusions."

Wyoming officials say they will launch another year-long investigation to reach their own conclusions about Pavillion's water.

Meanwhile, local residents remain suspended in a strange limbo

While controversy has swirled around the deep well test results -- and critics have hailed the agency's retreat as an admission that it could not defend its science -- the shallow well contamination and waste pits have been all but forgotten.

The Agency for Toxic Substances and Disease Registry, the federal government's main agency for evaluating health risk from pollution, has advised Pavillion [11] residents not to bathe, cook with, or drink the water flowing from their taps. Some have reported worsening health conditions they suspect are related to the pollution. They are being provided temporary drinking water from the state in large cisterns. **

The EPA opened its inquiry in Dimock, Pa., after residents provided it with private water tests detecting contaminants and complained that state regulators weren't doing enough to investigate the cause.

When an elderly woman's water well exploded on New Year's morning [12] in 2009, Pennsylvania officials discovered pervasive methane contamination in the well water of 18 homes and linked it to bad casing and cementing in gas company wells. In 2010, they took a series of steps [13] against the drilling company involved, citing it for regulatory violations, barring it from new drilling until it proved its wells would not leak and requiring it to temporarily supply water to affected homes.

But residents said state officials hadn't investigated whether the drilling was responsible for the chemicals in their water. The EPA stepped in [14] to find out if residents could trust the water to be safe after the drilling company stopped bringing replacement supplies.

Starting in early 2012, federal officials tested water in more than five dozen homes for pollutants, finding hazardous levels of barium, arsenic and magnesium, all compounds that can occur naturally, and minute amounts of other contaminants, including several known to cause cancer.

Still, the concentration of pollutants [15] was not high enough to exceed safe drinking water standards in most of the homes, the EPA found (in five homes, filtering systems were installed to address concerns). Moreover, none of the contaminants – except methane – pointed clearly to drilling. The EPA ended its investigation [16] that July.

Critics pointed to the Dimock investigation as a classic example of the EPA being overly aggressive on fracking and then being proven wrong.

Yet, as in Pavillion, the agency concluded its inquiry without following through on the essential question of whether Dimock residents face an ongoing risk from too much methane, which is not considered unsafe to drink, but can produce fumes that lead to explosions.

The EPA also never addressed whether drilling – and perhaps the pressure of fracking – had contributed to moving methane up through cracks in the earth into their water wells.

As drilling has resumed in Dimock, so have reports of ongoing methane leaks [17]. On June 24, the National Academy of Sciences published a report [18] by Duke University researchers that underscored a link between the methane contamination in water in Dimock and across the Marcellus shale, and the gas wells being drilled deep below.

The gas industry maintains that methane is naturally occurring [19] and, according to a response issued by the industry group Energy In Depth after the release of the Duke research, “there’s still no evidence of hydraulic fracturing fluids migrating from depth to contaminate aquifers.” **

In opening an inquiry in Parker County, Texas, in late 2010, the EPA examined a question similar to the one it faced in Dimock: Was a driller responsible for methane gas bubbling up in residents’ water wells?

This time, though, tests conducted by a geologist hired by the agency appeared to confirm that the methane in the wells had resulted from drilling, rather than occurring naturally.

"The methane that was coming out of that well … was about as close a match as you are going to find," said the consultant, Geoffrey Thyne, a geochemist and expert in unconventional oil and gas who has been a member of both the EPA’s Science Advisory Board for hydraulic fracturing, and a National Research Council committee to examine coalbed methane development.

The EPA issued an “imminent and substantial endangerment order” [20] forcing Range Resources, the company it suspected of being responsible, to take immediate action to address the contamination.

But once again, the EPA’s actions ignited an explosive response from the oil and gas industry, and a sharp rebuke from Texas state officials, who insisted that their own data and analysis proved Range had done no harm.

According to the environmental news site Energy Wire [21], Ed Rendell, the former Governor of Pennsylvania, whose law firm lobbies on behalf of energy companies, also took up Range's case with then-EPA Administrator Lisa Jackson.

Internal EPA emails used in the EnergyWire report and also obtained by ProPublica discuss Rendell's meeting with then-EPA Administrator Lisa Jackson, though Range has denied it employed Rendell to argue on its behalf. Neither the EPA nor Rendell responded to a request for comment on the Parker County case.
In March 2012, the EPA dropped its case against Range without explanation. Its administrator in Texas at the time had been assailed for making comments that seemed to show an anti-industry bias. He subsequently lost his job. An Associated Press investigation found that the EPA abandoned its inquiry after Range threatened not to cooperate with the EPA on its other drilling-related research.

Agency critics see a lack of will, rather than a lack of evidence, in the EPA's approach in Parker County and elsewhere.

"It would be one thing if these were isolated incidents," said Alan Septoff, communications director for Earthworks, an environmental group opposed to fracking. "But every time the EPA has come up with something damning, somehow, something magically has occurred to have them walk it back." **

So where does this leave the EPA's remaining research into the effects of fracking?

The agency has joined with the Department of Energy, U.S. Geological Survey and the Department of Interior to study the environmental risks of developing unconventional fuels such as shale gas, but those involved in the collaboration say that little has happened.

That leaves the EPA's highly anticipated national study on hydraulic fracturing [22].

When the EPA announced it was ending its research in Pavillion, it pointed to this study as a "major research program."

"The agency will look to the results of this program as the basis for its scientific conclusions and recommendations on hydraulic fracturing," it said in a statement issued in partnership with Wyoming Gov. Matt Mead.

That national study will concentrate on five case studies [23] in Pennsylvania, Texas, North Dakota and Colorado.

It will not, however, focus on Pavillion or Parker County or Dimock.

Nor will it devote much attention to places like Sublette County, Wy., where state and federal agencies have found both aquifer contamination and that drilling has caused dangerous levels of emissions and ozone pollution.

It will be a long time before the EPA's national study can inform the debate over fracking. While the agency has promised a draft by late 2014, it warned last month that no one should expect to read the final version before sometime in 2016, the last full year of President Obama's term.

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4.17 2013-08-08 - New Study Finds High Levels of Arsenic in Groundwater Near Fracking Sites

Brian Fontenot and Kevin Schug, two of the authors of a new study that ties fracking to arsenic contamination. (University of Texas Arlington)

by Theodoric Meyer *ProPublica, Aug. 8, 2013, 10:45 a.m.*

A recently published study by researchers at the University of Texas at Arlington found elevated levels of arsenic and other heavy metals in groundwater near natural gas fracking sites in Texas' Barnett Shale.

While the findings are far from conclusive, the study provides further evidence tying fracking to arsenic contamination. An internal Environmental Protection Agency PowerPoint presentation recently obtained by the Los Angeles Times warned that wells near Dimock, Pa., showed elevated levels of arsenic in the groundwater. The EPA also found arsenic in groundwater near fracking sites in Pavillion, Wyo., in 2009 — a study the agency later abandoned.

ProPublica talked with Brian Fontenot, the paper's lead author, about how his team carried out the study and why it matters. (Fontenot and another author, Laura Hunt, work for the EPA in Dallas, but they conducted the study on their own time in collaboration with several UT Arlington researchers.) Here's an edited version of our interview:

What led you guys to do the study?

We were sort of talking around lunch one day, and came up with the idea of actually going out and testing water in the Barnett Shale. We'd heard all the things that you see in the media, all the sort of really left-wing stuff and right-wing stuff, but there weren't a whole lot of answers out there in terms of an actual scientific study of water in the Barnett Shale. Our main intent was to bring an unbiased viewpoint here — to just look at the water, see if we could find anything, and report what we found.

What kind of previous studies had been done in this vein?

The closest analog that I could find to our type of study are the things that have been done in the Marcellus Shale, with Rob Jackson's group out at Duke University. Ours is set up very similarly to theirs in that we went out to private landowners' wells and sampled their water wells and assayed them for various things. We decided to go with a list of chemicals thought to be included in hydraulic fracturing that was actually released in a congressional report. Our plan was to sample everyone's water that we could, and then go through that list of these potential chemical compounds within the congressional list.

How did you do it?

We were able to get a press release put out from UT Arlington that went into the local newspapers that essentially called for volunteers to be participants in the study. For being a participant, you would get free water testing, and we would tell them our results. We were upfront with everyone about, you know, we don't have a bias, we're not anti-industry, we're not pro-industry. We're just here to finally get some scientific data on this subject. And we had a pretty overwhelming response.

From there we chose folks that we would be able to get to. We had to work on nights and weekends, because we had an agreement with EPA to work on this study outside of work hours. So we spent quite a few weekend days going out to folks who had responded to our call and sampling their water. But that wasn't quite enough. We also had to get samples from within the Barnett Shale in areas where fracking was not going on, and samples from outside the Barnett Shale where there's no fracking going on, because we wanted to have those for reference samples. For those samples we went door to door and explained to folks what our study was about.

We have people that were pro-industry that wanted to participate in this study to help out — saying, you know, 'You're not going to find anything and I'm going to help you prove it.' And we also had folks that were determined to find problems. We have the whole gamut of folks represented in our study.

We would take a water well, and we would go directly to the head, the closest we could get to the actual water source coming out of the ground, and we would purge that well for about 20 minutes. That ensures that you're getting fresh water from within the aquifer. So we didn't take anything from the tap, and nothing that had been through any kind of filtration system. This was as close to the actual groundwater as we could get. We took some measurements, and then we took several samples back to UT Arlington for a battery of chemistry analyses. That's where we went through and looked for the various volatile organic compounds and heavy metals and methanols and alcohols and things like that.

What did you find?

We found that there were actually quite a few examples of elevated constituents, such as heavy metals, the main players being arsenic, selenium and strontium. And we found each of those metals at levels that are above EPA's maximum contaminate limit for drinking water.

These heavy metals do naturally occur in the groundwater in this region. But we have a historical dataset that points to the fact that the levels we found are sort of unusual and not natural. These really high levels differ from what the groundwater used to be like before fracking came in. And when you look at the location of the natural gas wells, you find that any time you have water wells that exceed the maximum contaminate limit for any of these heavy metals, they are within about three kilometers of a natural gas well. Once you get a private water well that's not very close to a natural gas well, all of these heavy metals come down. But just because you're close to a natural gas well does not mean you're guaranteed to have elevated contaminate levels. We had quite a few samples that were very close to natural gas wells that had no problems with their water at all.

We also found a few samples that had measureable levels of methanol and ethanol, and these are two substances that don't naturally occur in groundwater. They can actually be created by bacterial interactions underwater, but whenever methanol or ethanol occur in the environment, they're very fleeting and transient. So for us to be able to actually randomly take a grab sample and detect detectable methanol and ethanol — that implies that there may be a continuous source of this.

You found levels of arsenic in areas with fracking that were almost 18 times higher than in areas without fracking or in the historical data. What would happen to someone who drank that water?

Arsenic is a pretty well-known poison. If you experience a lot of long-term exposure to arsenic, you get a lot of different risks, like skin damage, problems with the circulatory system or even an increased risk of cancer. The levels that we found would not be a lethal dose, but they're certainly levels that you would not want to be exposed to for any extended period of time.

What about the other stuff you found?

The heavy metals are a little bit different because they are known to be included in some fracking recipes. But they're also naturally occurring compounds. We think the problem is that they're becoming concentrated at levels that aren't normal as a result of some aspect of natural gas extraction.

It's not necessarily that we're saying fracking fluid getting out. We don't have any evidence of that. But there are many other steps involved, from drilling the hole to getting the water back out. A lot of these can actually cause different scenarios whereby the naturally occurring heavy metals will become concentrated in ways they normally wouldn't. For example, if you have a private water well that's not kept up well, you'll have a scale of rust on the inside. And if someone were to do a lot of drilling nearby, you may find some pressure waves or vibrations that would cause those rust particles to flake out into the water. Arsenic is bound up inside that rust, and that can actually mobilize arsenic that would never be in the water otherwise.

Methanol and ethanol are substances that should not be very easy to find in the groundwater naturally. We definitely know that those are on the list of things that are known to be in hydraulic fracturing fluid. But we were unable to actually sample any hydraulic fracturing fluid, so we can't make any claims that we have evidence fluids got into the water.

Have you talked with the homeowners whose wells you sampled?

We have shown those homeowners the results. I think most of the folks that had high levels of heavy metals were not necessarily surprised. You hear so much I think maybe they were expecting it to come back with something even more extreme than that. I don't want to say they were relieved, but I think they all sort of took the news in stride and realized, OK, well, as a private well owner there's no state or federal agency that provides any kind of oversight or regulation, so it's incumbent on that well owner to get testing done and get any kind of remediation.

Do you think fracking is responsible for what you found?

Well, I can't say we have a smoking gun. We don't want the public to take away from this that we have pegged fracking as the cause of these issues. But we have shown that these issues do occur in close relation, geographically, to natural gas extraction. And we have this historical database from pretty much the same exact areas that we sampled that never had these issues until the onset of all the fracking. We have about 16,000 active wells here in the Barnett Shale, and that's all popped up in about the last decade, so it's been a pretty dramatic increase.

We noticed that when you're closer to a well, you're more likely to have a problem, and that today's samples have problems, while yesterday's samples before the fracking showed up did not. So we think that the strongest argument we can say is that this needs more research.

4.18 2013-08-13 _ Unfair Share - How Oil and Gas Drillers Avoid Paying Royalties

A drilling rig in Springville, Pa. Income from oil and gas production doesn't always trickle down to landowners, as companies find ways to minimize the share they pay in royalties. (Alex Brandon/AP Photo)

by Abrahm Lustgarten *ProPublica, Aug. 13, 2013, 10:20 a.m.*

Don Feusner ran dairy cattle on his 370-acre slice of northern Pennsylvania until he could no longer turn a profit by farming. Then, at age 60, he sold all but a few Angus and aimed for a comfortable retirement on money from drilling his land for natural gas instead.

It seemed promising. Two wells drilled on his lease hit as sweet a spot as the Marcellus shale could offer – tens of millions of cubic feet of natural gas gushed forth. Last December, he received a check for $8,506 for a month's share of the gas.

Then one day in April, Feusner ripped open his royalty envelope to find that while his wells were still producing the same amount of gas, the gusher of cash had slowed. His eyes cascaded down the page to his monthly balance at the bottom: $1,690.

Chesapeake Energy, the company that drilled his wells, was withholding almost 90 percent of Feusner's share of the income to cover unspecified "gathering" expenses and it wasn't explaining why.
"They said you're going to be a millionaire in a couple of years, but none of that has happened," Feusner said. "I guess we're expected to just take whatever they want to give us."

Like every landowner who signs a lease agreement to allow a drilling company to take resources off his land, Feusner is owed a cut of what is produced, called a royalty.

In 1982, in a landmark effort to keep people from being fleeced by the oil industry, the federal government passed a law establishing that royalty payments to landowners would be no less than 12.5 percent of the oil and gas sales from their leases.

From Pennsylvania to North Dakota, a powerful argument for allowing extensive new drilling has been that royalty payments would enrich local landowners, lifting the economies of heartland and rural America. The boom was also supposed to fill the government's coffers, since roughly 30 percent of the nation's drilling takes place on federal land.

Over the last decade, an untold number of leases were signed, and hundreds of thousands of wells have been sunk into new energy deposits across the country.

But manipulation of costs and other data by oil companies is keeping billions of dollars in royalties out of the hands of private and government landholders, an investigation by ProPublica has found.

An analysis of lease agreements, government documents and thousands of pages of court records shows that such underpayments are widespread. Thousands of landowners like Feusner are receiving far less than they expected based on the sales value of gas or oil produced on their property. In some cases, they are being paid virtually nothing at all.

In many cases, lawyers and auditors who specialize in production accounting tell ProPublica energy companies are using complex accounting and business arrangements to skim profits off the sale of resources and increase the expenses charged to landowners.

Deducting expenses is itself controversial and debated as unfair among landowners, but it is allowable under many leases, some of which were signed without landowners fully understanding their implications. But some companies deduct expenses for transporting and processing natural gas, even when leases contain clauses explicitly prohibiting such deductions. In other cases, according to court files and documents obtained by ProPublica, they withhold money without explanation for other, unauthorized expenses, and without telling landowners that the money is being withheld.

Significant amounts of fuel are never sold at all – companies use it themselves to power equipment that processes gas, sometimes at facilities far away from the land on which it was drilled. In Oklahoma, Chesapeake deducted marketing fees from payments to a landowner – a joint owner in the well – even though the fees went to its own subsidiary, a pipeline company called Chesapeake Energy Marketing. The landowner alleged the fees had been disguised in the form of lower sales prices. A court ruled that the company was entitled to charge the fees.

Costs such as these are normally only documented in private transactions between energy companies, and are almost never detailed to landowners.

"To find out how the calculation is done, you may well have to file a lawsuit and get it through discovery," said Owen Anderson, the Eugene Kuntz Chair in Oil, Gas & Natural Resources at the University of Oklahoma College of Law, and an expert on royalty disputes. "I'm not aware of any state that requires that level of disclosure."

To keep royalties low, companies sometimes set up subsidiaries or limited partnerships to which they sell oil and gas at reduced prices, only to recoup the full value of the resources when their subsidiaries resell it. Royalty payments are usually based on the initial transaction.

In other cases, companies have bartered for services off the books, hiding the full value of resources from landowners. In a 2003 case in Louisiana, for example, Kerr McGee, now owned by Anadarko Petroleum, sold its oil for a fraction of its value – and paid royalties to the government on the discounted amount – in a trade arrangement for marketing services that were never accounted for on its cash flow statements. The federal government sued, and won.

The government has an arsenal of tools to combat royalty underpayment. The Department of Interior has rules governing what deductions are allowable. It also employs an auditing agency that, while far from perfect, has uncovered more than a dozen instances in which drillers were “willful” in deceiving the government on royalty payments just since 2011. A spokesman for the Department of Interior’s Office of Natural Resources Revenue says that over the last three decades, the government has recouped more than $4 billion in unpaid fees from such cases.

There are few such protective mechanisms for private landowners, though, who enter into agreements without regulatory oversight and must pay to audit or challenge energy companies out of their own pockets.

ProPublica made several attempts to contact Chesapeake Energy for this article. The company declined, via email, to answer any questions regarding royalties, and then did not respond to detailed sets of questions submitted afterward. The leading industry trade group, the American Petroleum Institute, also declined to comment on landowners’ allegations of underpayments, saying that individual companies would need to respond to specific claims.

Anderson acknowledged that many landowners enter into contracts without understanding their implications and said it was up to them to do due diligence before signing agreements with oil and gas companies.

“The duty of the corporation is to make money for shareholders,” Anderson said. “Every penny that a corporation can save on royalties is a penny of profit for shareholders, so why shouldn’t they try to save every penny that they can on payments to royalty owners?”

Gas flows up through a well head on Feusner’s property, makes a couple of turns and passes a meter that measures its volume. Then it flows into larger pipes fed by multiple pipelines in a process the industry calls “gathering.” Together, the mixed gases might get compressed or processed to improve the gas quality for final sale, before feeding into a larger network of pipelines that extends for hundreds of miles to an end point, where the gas is sold and ultimately distributed to consumers.

Each section of pipeline is owned and managed by a different company. These companies buy the gas from Chesapeake, but have no accountability to Feusner. They operate under minimal regulatory oversight, and have sales contracts with the well operator, in this case Chesapeake, with terms that are private. Until Chesapeake sold its pipeline company last winter, the pipelines were owned by its own subsidiaries.

As in many royalty disputes, it is not clear exactly which point of sale is the one on which Feusner's payments should be based – the last sale onto the open market or earlier changes in custody. It's equally unclear whether the expenses being charged to Feusner are incurred before or after that point of sale, or what processes, exactly, fall under the term "gathering." Definitions of that term vary, depending on who is asked. In an email, a spokesperson for Chesapeake declined to say how the company defines gathering.

Making matters more complicated, the rights to the gas itself are often split into shares, sometimes among as many as a half-dozen companies, and are frequently traded. Feusner originally signed a lease with a small drilling company, which sold the rights to the lease to Chesapeake. Chesapeake sold a share of its rights in the lease to a Norwegian company, Statoil, which now owns about a one-third interest in the gas produced from Feusner's property.

Chesapeake and Statoil pay him royalties and account for expenses separately. Statoil does not deduct any expenses in calculating Feusner's royalty payments, possibly because it has a different interpretation of what's allowed.

"Statoil's policy is to carefully look at each individual lease, and to take post-production deductions only where the lease and the law allow for it," a company spokesman wrote in an email. "We take our production in kind from Chesapeake and we have no input into how they interpret the leases."

Once the gas is produced, a host of opaque transactions influence how sales are accounted for and proceeds are allocated to everyone entitled to a slice. The chain of custody and division of shares is so complex that even the country's best forensic accountants struggle to make sense of energy companies' books.

Feusner's lease does not give him the right to review Chesapeake's contracts with its partners, or to verify the sales figures that the company reports to him. Pennsylvania – though it recently passed a law requiring that the total amount of deductions be listed on royalty statements – has no laws dictating at what point a sale price needs to be set, and what expenses are legitimate.

Concerns about royalties have begun to attract the attention of state legislators, who held a hearing on the issue in June. Some have acknowledged a need to clarify minimum royalty guarantees in the state, but so far, that hasn't happened.

"If you have a system that is not transparent from wellhead to burner tip and you hide behind confidentiality, then you have something to hide," Jerry Simmons, executive director of the National Association of Royalty Owners (NARO), the premier organization representing private landowners in the U.S., told ProPublica in a 2009 interview. Simmons said recently that his views had not changed, but declined to be interviewed again. "The idea that regulatory agencies don't know the volume of gas being produced in this country is absurd."

Because so many disputes come down to interpretations of contract language, companies often look to courts for clarification. Not many royalty cases have been argued in Pennsylvania so far, but in 2010, a landmark decision, Kilmer v. Elexco Land Services, set out that the state's minimum royalty guarantee applied to revenues before expenses were calculated, and that, when allowed by leases, energy companies were free to charge back deductions against those royalties.

Since then, Pennsylvania landowners say, Chesapeake has been making larger deductions from their checks. (The company did not respond to questions about this.) In April, Feusner's effective royalty rate on the gas sold by Chesapeake was less than 1 percent.

Paul Sidorek is an accountant representing some 60 northeastern Pennsylvania landowners who receive royalty income from drilling. He's also a landowner himself – in 2009, he leased 145 acres, and that lease was eventually sold to Chesapeake. Well aware of the troubles encountered by others, Sidorek negotiated a 20 percent royalty and made sure his lease said explicitly that no expenses could be deducted from the sale of the gas produced on his property.

Yet now, Sidorek says, Chesapeake is deducting as much as 30 percent from his royalties, attributing it to "gathering" and "third party" expenses, an amount that adds up to some $40,000 a year.

“Now that the royalties are flowing, some people just count it as a blessing and say we don’t care what Chesapeake does, it’s money we wouldn’t have had before,” Sidorek said. But he’s filed a lawsuit. “I figure I could give my grandson a first-class education for what Chesapeake is deducting that they are not entitled to, so I’m taking it on.”

Landowners, lawyers, legislators and even some energy industry groups say Chesapeake stands out for its confusing accounting and tendency to deduct the most expenses from landowners’ royalty checks in Pennsylvania.

“They’ve had a culture of doing cutthroat business,” said Jackie Root, president of Pennsylvania’s chapter of the National Association of Royalty Owners.

Chesapeake did not respond to questions on whether its approach differs from that of other companies.
Root and others report good working relationships with other companies operating wells in Pennsylvania, and say that deductions – if they occur at all – are modest. Statoil, which has an interest in a number of Chesapeake wells, does not deduct any expenses on its share of many of the same leases. In an email from a spokesperson, the company said “We always seek to deal with our lease holders in a fair manner.”
Several landowners said that not only do deductions vary between companies using the same gas “gathering” network – sales prices do as well.

On Sidorek’s royalty statements, for example, Chesapeake and Statoil disclose substantially different sales prices for the same gas moved through the same system.

“If Statoil can consistently sell the gas for $.25 more, and Chesapeake claims it’s the premier producer in the country, then why the hell can’t they get the same price Statoil does for the same gas on the same day?” Sidorek wondered.

He thinks Chesapeake was giving a discount to a pipeline company it used to own. Chesapeake did not respond to questions about the price discrepancy.

Chesapeake may be the focus of landowner ire in Pennsylvania, but across the country thousands of landowners have filed similar complaints against many oil and gas producers.

In dozens of class actions reviewed by ProPublica, landowners have alleged they cannot make sense of the expenses deducted from their payments or that companies are hiding charges

Publicly traded oil and gas companies also have disclosed settlements and judgments related to royalty disputes that, collectively, add up to billions of dollars.

In 2003, a jury found that Exxon had defrauded the state of Alabama out of royalty payments and ordered the company to pay nearly $103 million in back royalties and interest, plus $11.8 billion in punitive damages. (The punitive damages were reduced to $3.5 billion on appeal, and then eliminated by the state supreme court in 2007.)

In 2007, a jury ordered a Chesapeake subsidiary to pay $404 million, including $270 million in punitive damages, for cheating a class of leaseholders in West Virginia. In 2010, Shell was hit with a $66 million judgment, including $52 million in punitive fines, after a jury decided the company had hidden a prolific well and then intentionally misled landowners when they sought royalties. The judgment was upheld on appeal.

Since the language of individual lease agreements vary widely, and some date back nearly 100 years, many of the disagreements about deductions boil down to differing interpretations of the language in the contract.

In Pennsylvania, however, courts have set few precedents for how leases should be read and substantial hurdles stand in the way of landowners interested in bringing cases.

Pennsylvania attorneys say many of their clients' leases do not allow landowners to audit gas companies to verify their accounting. Even landowners allowed to conduct such audits could have to shell out tens of thousands of dollars to do so.

When audits turn up discrepancies, attorneys say, many Pennsylvania leases require landowners to submit to arbitration – another exhaustive process that can cost tens of thousands of dollars. Arbitration clauses can also make it more difficult for landowners to join class action suits in which individuals can pool their resources and gain enough leverage to take on the industry.

"They basically are daring you to sue them," said Aaron Hovan, an attorney in Tunkhannock, Pa., representing landowners who have royalty concerns. "And you need to have a really good case to go through all of that, and then you could definitely lose."

All of these hurdles have to be cleared within Pennsylvania's four-year statute of limitations. Landowners who realize too late that they have been underpaid for years – or who inherit a lease from an ailing parent who never bothered to check their statements – are simply out of luck.

Even if a gas company were found liable for underpaying royalties in Pennsylvania, it would have little to fear. It would owe only the amount it should have paid in the first place; unlike Oklahoma and other states, Pennsylvania law does not allow for any additional interest on unpaid royalties and sets a very high bar for winning punitive penalties.

"They just wait to see who challenges them, they keep what they keep, they give up what they lose," said Root, the NARO chapter president. "It may just be part of their business decision to do it this way."

4.19 2014-03-05 _ Drilling for Certainty - The Latest in Fracking Health Studies

(Bartek Sadowski/Bloomberg via Getty Images)

by Naveena Sadasivam *ProPublica, March 5, 2014, 12:02 p.m.*

For years, environmentalists and the gas drilling industry have been in a pitched battle over the possible health implications of hydro fracking. But to a great extent, the debate — as well as the emerging lawsuits and the various proposed regulations in numerous states — has been hampered by a shortage of science.
In 2011, when ProPublica first reported on the different health problems afflicting people living near gas drilling operations, only a handful of health studies had been published. Three years later, the science is far from settled, but there is a growing body of research to consider.

Below, ProPublica offers a survey of some of that work. The studies included are by no means a comprehensive review of the scientific literature. There are several others that characterize the chemicals in fracking fluids, air emissions and waste discharges. Some present results of community level surveys.

Yet, a long-term systematic study of the adverse effects of gas drilling on communities has yet to be undertaken. Researchers have pointed to the scarcity of funding available for large-scale studies as a major obstacle in tackling the issue.

A review of health-related studies published last month in *Environmental Science & Technology* concluded that the current scientific literature puts forward “both substantial concerns and major uncertainties to address.”

Still, for some, waiting for additional science to clarify those uncertainties before adopting more serious safeguards is misguided and dangerous. As a result, a number of researchers and local activists have been pushing for more aggressive oversight immediately.

The industry, by and large, has regarded the studies done to date — a number of which claim to have found higher rates of illness among residents living close to drilling wells — as largely anecdotal and less than convincing.

“The public health sector has been absent from this debate,” said Nadia Steinzor, a researcher on the Oil and Gas Accountability Project at the environmental nonprofit, Earthworks.

Departments of health have only become involved in states such as New York and Maryland where regulators responded to the public’s insistence on public health and environmental reviews before signing off on fracking operations. The states currently have a moratorium on fracking.

New York State Health Commissioner Nirav Shah is in fact conducting a review of health studies to present to Governor Andrew Cuomo before he makes a decision on whether to allow fracking in the state. It is unclear when the results of the review will be publicly available.

Other states such as Pennsylvania and Texas, however, have been much more supportive of the gas industry. For instance, Texas has been granting permits for fracking in ever increasing numbers while at the same time the Texas Commission on Environmental Quality, the agency that monitors air quality, has had its budget cut substantially.

1. **An Exploratory Study of Air Quality near Natural Gas Operations.** ***Human and Ecological Risk Assessment, 2012.***

The study, performed in Garfield County, Colo., between July 2010 and October 2011, was done by researchers at The Endocrine Disruption Exchange, a non-profit organization that examines the impact of low-level exposure to chemicals on the environment and human health.

In the study, researchers set up a sampling station close to a well and collected air samples every week for 11 months, from when the gas wells were drilled to after it began production. The samples produced evidence of 57 different chemicals, 45 of which they believe have some potential for affecting human health.

In almost 75 percent of all samples collected, researchers discovered methylene chloride, a toxic solvent that the industry had not previously disclosed as present in drilling operations. The researchers noted that the greatest number of chemicals were detected during the initial drilling phase.
While this study did catalogue the different chemicals found in air emissions from gas drilling operations, it did not address exposure levels and their potential effects. The levels found did not exceed current safety standards, but there has been much debate about whether the current standards adequately address potential health threats to women, children and the elderly.

The researchers admitted their work was compromised by their lack of full access to the drilling site. The air samples were collected from a station close to what is known as the well pad, but not the pad itself.

The gas drilling industry has sought to limit the disclosure of information about its operations to researchers. They have refused to publicly disclose the chemicals that are used in fracking, won gag orders in legal cases and restricted the ability of scientists to get close to their work sites. In a highly publicized case last year, a lifelong gag order was imposed on two children who were parties to a legal case that accused one gas company of unsafe fracking operations that caused them to fall sick.

In 2009, the Independent Petroleum Association of America started Energy In Depth, a blog that confronts activists who are fighting to ban fracking and challenges research that in any way depicts fracking as unsafe.

Energy In Depth responded to this Garfield County study and criticized its lack of proper methodology. The blog post also questioned the objectivity of the researchers, asserting that their “minds were already made up.”

The industry has also been performing its own array of studies.

Last year, for instance, an industry-funded study on the methane emissions from fracking wells was published in the prestigious journal, *Proceedings of the National Academy of Sciences.* It concluded that only very modest amounts of methane — a known contributor to climate change — was being emitted into the air during fracking operations.

The study came under heavy criticism from Cornell researcher Robert Howarth, who two years prior had published work that claimed methane emissions from shale gas operations were far more significant.
“This study is based only on evaluation of sites and times chosen by industry,” he said.

2. **Birth Outcomes and Natural Gas Development.** ***Environmental Health Perspectives, 2014.***

The study examined babies born from 1996 to 2009 in rural Colorado locations — the state has been a center of fracking for more than a decade. It was done by the Colorado School of Public Health and Brown University.

The study asserted that women who lived close to gas wells were more likely to have children born with a variety of defects, from oral clefts to heart issues. For instance, it claimed that babies born to mothers who lived in areas dense with gas wells were 30 percent more likely to have congenital heart defects.

The researchers, however, were unable to include data on maternal health, prenatal care, genetics and a host of other factors that have been shown to increase the risk of birth defects because that information was not publicly available. A common criticism of many scientific studies is that they do not fully analyze the possibility of other contributing factors.

The study has thus come under attack from both the industry and state public health officials. In a statement, Dr. Larry Wolk, the state’s Chief Medical Officer, said “people should not rush to judgment” as “many factors known to contribute to birth defects were ignored” in the study.

But Lisa McKenzie, one of the lead authors of the study, said there was value to the work.

"What I think this is telling us is that we need to do more research to tease out what is happening and to see if these early studies hold up when we do more rigorous research," she said.

In Pennsylvania, Elaine Hill, a graduate student at Cornell University, obtained data on gas wells and births between 2003 and 2010. She then compared birth weights of babies born in areas of Pennsylvania where a well had been permitted but never drilled and areas where wells had been drilled. Hill found that the babies born to mothers within 2.5 kilometers (a little over 1.5 miles) of drilled gas sites were 25 percent more likely to have low birth weight compared to those in non-drilled areas. Babies are considered as having low birth weight if they are under 2500 grams (5.5 pounds).

Hill's work is currently under review by a formal scientific journal, a process that could take three or four years.

3. Health Risks and Unconventional Natural Gas Resources. *Science of the Total Environment, 2012.*

Between January 2008 and November 2010, researchers at the Colorado School of Public Health collected air samples in Garfield County, Colo., which has been experiencing intensive drilling operations. Researchers found the presence of a number of hydrocarbons including benzene, trimethylbenzene and xylene, all of which have been shown to pose health dangers at certain levels.

Researchers maintained that those who lived less than half a mile from a gas well had a higher risk of health issues. The study also found a small increase in cancer risk and alleged that exposure to benzene was a major contributor to the risk.

"From the data we had, it looked like the well completion phase was the strongest contributor to these emissions," said Lisa McKenzie, the lead author of the study.

During the completion phase of drilling, a mixture of water, sand and chemicals is forced down the well at high pressure, and is then brought back up. The returning mixture, which contains radioactive materials and some of the natural gas from the geological formation, is supposed to be captured. But at times the mixture comes back up at pressures higher than the system can handle and the excess gas is directly vented into the air.

“I think we ought to be focused on the whole thing from soup to nuts because a lot of the potential hazards aren’t around the hydraulic fracturing step itself,” said John Adgate, chair of the Department of Environmental and Occupational Health at the Colorado School of Public Health and co-author on the study.

Energy In Depth, the industry blog, responded at length to this study and cited several “bad inputs” which had affected the results of the study. The researchers’ assumptions and data were criticized. For instance, the researchers had assumed that Garfield residents would remain in the county until the age of 70 in order to estimate the time period over which they would be exposed to the emissions.

“Unless the ‘town’ is actually a prison, this is a fundamentally flawed assumption about the length and extent of exposure,” Energy In Depth said.

4.20 2014-03-13 _ Chesapeake Energy's $5 Billion Shuffle

Joe Drake (Abrahm Lustgarten for Propublica)

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At the end of 2011, Chesapeake Energy, one of the nation's biggest oil and gas companies, was teetering on the brink of failure.

Its legendary chief executive officer, Aubrey McClendon, was being pilloried for questionable deals, its stock price was getting hammered and the company needed to raise billions of dollars quickly.

The money could be borrowed, but only on onerous terms. Chesapeake, which had burned money on a lavish steel-and-glass office complex in Oklahoma City even while the selling price for its gas plummeted, already had too much debt.

In the months that followed, Chesapeake executed an adroit escape, raising nearly $5 billion with a previously undisclosed twist: By gouging many rural landowners out of royalty payments they were supposed to receive in exchange for allowing the company to drill for natural gas on their property.

In lawsuits in state after state, private landowners have won cases accusing companies like Chesapeake of stiffing them on royalties they were due. Federal investigators have repeatedly identified underpayments of royalties for drilling on federal lands, including a case in which Chesapeake was fined $765,000 for “knowing or willful submission of inaccurate information” last year.

Last month, Pennsylvania governor Tom Corbett, who is seeking reelection, sent a letter to Chesapeake’s CEO saying the company’s expense billing “defies logic” and called for the state Attorney General to open an investigation.

McClendon, a swashbuckling executive and fracking pioneer, was ultimately pushed out of his job. But the impact of the financial maneuvers that he made to save the company will reverberate for years. The winners, aside from Chesapeake, were a competing oil company and a New York private equity firm that fronted much of the money in exchange for promises of double-digit returns for the next two decades.

The losers were landowners in Pennsylvania and elsewhere who leased their land to Chesapeake and saw their hopes of cashing in on the gas-drilling boom vanish without explanation.
People like Joe Drake.

“I got the check out of the mail… I saw what the gross was,” said Drake, a third-generation Pennsylvania farmer whose monthly royalty payments for the same amount of gas plummeted from $5,300 in July 2012 to $541 last February. This sort of precipitous drop can reflect gyrations in the price of gas. But in this case, Drake’s shrinking check resulted from a corporate decision by Chesapeake to radically reinterpret the terms of the deal it had struck to drill on his land. “If you or I did that we’d be in jail,” Drake said.

Chesapeake’s conduct is part of a larger national pattern in which many giant energy companies have maneuvered to pay as little as possible to the owners of the land they drill. Last year, a ProPublica investigation found that Pennsylvania landowners were paying ever-higher fees to companies for transporting their gas to market, and that Chesapeake was charging more than other companies in the region. The question was “why”?

ProPublica pieced together the story of how Chesapeake shifted borrowing costs to landowners from documents filed with the U.S. Securities and Exchange Commission, interviews with landowners, people who worked for the company and employees at other oil and gas concerns.

The deals took advantage of a simple economic principle: Monopoly power.

Boiled down to basics, they worked like this: When energy companies lease land above the shale rock that contains natural gas, they typically agree to pay the owner the market price for any gas they find, minus certain expenses.

Federal rules limit the tolls that can be charged on inter-state pipelines to prevent gouging. But drilling companies like Chesapeake can levy any fees they want for moving gas through local pipelines, known in the industry as gathering lines, that link backwoods wells to the nation's interstate pipelines. Property owners have no alternative but to pay up. There's no other practical way to transport natural gas to market.

Chesapeake took full advantage of this. In a series of deals, it sold off the network of local pipelines it had built in Pennsylvania, Ohio, Louisiana, Texas and the Midwest to a newly formed company that had evolved out of Chesapeake itself, raising $4.76 billion in cash.

In exchange, Chesapeake promised the new company, Access Midstream, that it would send much of the gas it discovered for at least the next decade through those pipes. Chesapeake pledged to pay Access enough in fees to repay the $5 billion plus a 15 percent return on its pipelines.

That much profit was possible only if Access charged Chesapeake significantly more for its services. And that's exactly what appears to have happened: While the precise details of Access' pricing remains private, immediately after the transactions Access reported to the SEC that it collected more money to move each unit of gas, while Chesapeake reported that it also paid more to have that gas moved. Access said that gathering fees are its predominant source of income, and that Chesapeake accounts for 84 percent of the company's business.

What's more, SEC documents show, Chesapeake retained a stake in the gathering process. While Chesapeake collected fees from landowners like Drake to cover the costs of what it paid Access to move the gas, Access in turn paid Chesapeake for equipment it used to complete that process, circulating at least a portion of the money back to Chesapeake.

ProPublica repeatedly sought comment and explanations from both Chesapeake and Access Midstream over the course of several months. Both companies declined to make executives available to discuss the deals or to respond to written questions submitted by ProPublica.

Days after the last of the deals closed, Drake and other landowners learned the expense of sending their gas through Access's pipelines would eat up nearly all of the money they had been previously earning from their wells. Some saw their monthly checks fall by as much as 94 percent.

An executive at a rival company who reviewed the deal at ProPublica's request said it looked like Chesapeake had found a way to make the landowners pay the principal and interest on what amounts to a multi-billion loan to the company from Access Midstream.

"They were trying to figure out any way to raise money and keep their company alive,'' said the executive, who declined to be named because it would jeopardize his dealings with Chesapeake. "I think they looked at it as an opportunity to effectively get disguised financing…that is going to be repaid at a premium.''

At 54, Joe Drake guns his six-wheeler up a steep rock-rutted trail on the backwoods of his 494-acre tract and

points to his property line, marked by a large maple in a sea of indistinguishable trees. He knows where it lies, because as a kid his father made him walk that line to string barbed wire. The wire is long gone, but a rusted snag remains entombed in the bark. Back then, the Drakes ran a dairy farm in these pastures.
“It’s just something you’ve got in your blood that you do,” Drake said. “But dairy farmers are a dying breed… It was a good way of life.”

Today, the milking stalls have been ripped out of a long barn that still carries the stench of their manure, but stores 20-foot stacks of bailed hay instead. Drake sold all 187 head of cattle two years ago, pinched by regulated milk prices and the rising costs of independent farming. He took out a second mortgage to keep the farm afloat.

Across the road, past his house and just beyond a stand of oak and ash, the hillside’s natural shape transitions to a steep slope of pushed dirt, capped by a 7-acre flat the size of a large gravel parking lot. In the middle stands a 6-foot stack of steel pipes and valves – a gas well.

When Chesapeake arrived at Drake’s door, he was optimistic. Drake plastered a “Drill, baby, drill” bumper sticker in the window of his Ford F-250 pickup. He welcomed the chance to draw an easy income from his land, and was unswayed when his neighbors raised questions about the environmental risks of drilling. Chesapeake promised Drake one-eighth the value of whatever it made from his well. It seemed like a fair deal.

If any driller was going to make money for Drake, he thought, it would be Chesapeake. The company had built an empire off finding and drilling natural gas discoveries as the fracking boom rolled across the country. With uncanny foresight, its founder, McClendon, locked up exclusive access to immense tracts of land across the country by promising property owners that their lives would be transformed by the wealth the gas under it would bring.

Then the company drilled furiously -- in Oklahoma, then Texas, Louisiana and later in Pennsylvania’s Marcellus Shale – catapulting itself to the rank of second-largest producer of natural gas in the United States. It made McClendon – who snatched up a stake in the Oklahoma City Thunder basketball team and moved into a stone mansion in the posh Oklahoma City suburb of Nichols Hills -- one of the richest men in the world.

McClendon – named by Forbes in 2011 as "America's Most Reckless Billionaire" -- would find his way into plenty of personal trouble. He took a personal stake in Chesapeake's wells, and then liquidated his stock in the company in order to cover his own losses, rattling investors and ringing corporate governance alarm bells. He drew scrutiny for selling his $12 million antique map collection to the company and ire for taking a $75 million bonus as Chesapeake struggled.

In 2012, he borrowed as much as a billion dollars from the company's private equity partners to fund his private interests. Separately, an investigation by Reuters alleged Chesapeake had rigged land leasing prices in Michigan, under McClendon's direction, sparking a federal criminal probe.

But McClendon's overarching design for the business nonetheless made it a formidable player. Chesapeake aggressively pursued business opportunities beyond its drilling. It created interlocking businesses and took advantage of tax breaks that deliver out-sized benefits to energy companies.

By structuring itself this way, Chesapeake earned a slice of profit from each step. Chesapeake's subsidiaries trucked the drilling materials, drilled the wells, fracked the gas, gathered and piped it away to a hub, and then marketed the end product – what economists call vertical integration. In fact, he built Chesapeake into a powerhouse, an echo of the old Standard Oil empire, positioned to control almost every variable and armed with the leverage to get its way.

Neither McClendon nor his staff responded to requests for comment for this article.

From early on, the company viewed the local pipelines as a profit source. Chesapeake formed subsidiaries to build and run the lines, then spun them off into a separate, publicly traded company. That company would eventually evolve into Access Midstream, when Chesapeake sold its shares – one of the three deals – for $2 billion in 2012.

The strategy paid dividends. At Chesapeake's headquarters, a group of new, distinctively-designed office buildings went up, with views south over the state capital and the city's small skyline. The company lavished its employees with perks, too. "They've got a 72,000-square-foot gym, free trainers… free Thunder tickets," said Andrea Watiker, who scheduled pipeline capacity for gas traders in one of the company's new towers.

Confident he was in good hands, Drake endured the trucks, dirt and noise that accompanied gas drilling and signed agreements that allowed Chesapeake to run pipelines across his fields. To transport the gas from Drake's well, Chesapeake built a pipeline that stretched south from within spitting distance of the New York border, cutting a wide swath through the forest. Then it went down beyond the white-spired church in Litchfield, and ran some 35 miles further to its handoff at the Tennessee interstate pipeline near the Susquehanna River.

What Drake didn't know at the time was that the pipeline was more than a way to move his gas to market. It would become part of a strategy to make more money off of Drake himself.

When the first gas flowed from the well on Drake's land in July 2012, it was abundant, and the royalty checks were fat. "We was hoping to get these loans paid off…with the big money," said Drake, who earned more than $59,400 from the first few months of production, referring to the mortgages on his farm.

That year, many Pennsylvania landowners began receiving similarly sized payments as thousands of new wells – many of them drilled by Chesapeake -- finally began producing gas. Pennsylvania fast approached Texas as the largest source of natural gas in the country, and with it, the prosperity long promised to this rural part of the United States seemed about to arrive.

But then, in January 2013, without warning or explanation, the expenses withheld from Chesapeake's royalty checks for use of the gathering pipelines tripled. Drake's income dwindled. His contract with Chesapeake – and Pennsylvania law that sets a minimum royalty share in the state – promised him at least 12.5 percent of the value of the gas. Drake says the company led him to believe any expenses would be negligible. "Well, they lied."

A few miles away, the same month, his brother-in-law had 94 percent of his gas income withheld to pay for what Chesapeake called "gathering fees." Others across the northern part of the state also saw their income slashed. "I've got a stack," said Taunya Rosenbloom, a lawyer representing Pennsylvania landowners with natural gas leases. She pulled the statements of all of her Chesapeake clients into an eight-inch pile on her desk. "Everyone is having this issue."

Drake found the statements Chesapeake mailed him each month mystifying. He pored over the papers, hired a lawyer, compared notes with his neighbors, but couldn't make sense of the charges.

Other Pennsylvanians were similarly baffled. Sometimes, Chesapeake charged different fees to neighbors whose wells fed into the same gathering line. Other times, companies that had partnered with Chesapeake on the same well charged vastly less for expenses. No one at the Chesapeake could seem to explain how the charges were set.

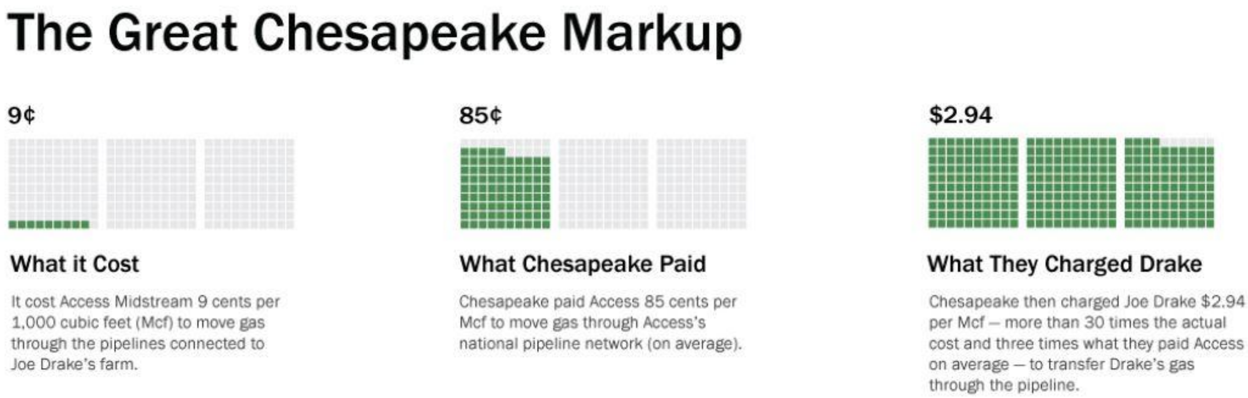
"There is no rhyme or reason why one client would have such an exorbitant amount taken out when another no more than 3 miles away has only 20 percent of their royalty taken," said Harold Moyer, an accountant in Bradford County, Pa., who represents more than 150 landowners with royalty rights. Moyer said he saw a dramatic difference between what Chesapeake usually charged compared to other energy companies in the area.

Different contracts may entitle Chesapeake to charge varying amounts. Some of the leases examined by ProPublica limit a landowner's share of expenses to 12.5 percent – or the same as their share of the proceeds. Other contracts prohibit Chesapeake from withholding any expenses at all. Drake's contract appears to allow Chesapeake to recoup as much money as it wants; it stipulates that he can be charged for the expense of gathering and transporting his gas without specifying his share of such expenses.

Gas drillers differ significantly in how much they charge landowners for expenses. The Norwegian energy company Statoil owns a portion of the gas extracted from Drake's well, as well as a portion of the gathering line that moves the gas to an interstate pipeline. Yet Statoil rakes off virtually nothing for its expenses, according to its statements. Statoil told ProPublica that it sells its gas independently and makes decisions about billing separately from Chesapeake.

"When it comes to deciding which, if any, deductions are appropriate, we make that assessment according to the terms of each lease and the applicable laws," wrote Ola Morten Aanestad, in an e-mailed response to questions.

Drake peers out the window, over the hills that descend from his porch into a valley brightening with the changing colors of fall, and scowls. He can't stand being indoors. He's worried that he'll spend most of next hunting season here at this table, trying to decipher Chesapeake's statements. His monthly gas statements pile up, unorganized, on the kitchen table, below a rack of deer antlers and beside two empty cans of Coors Light and a camouflage baseball cap.



Drake's gathering pipeline only extends a few dozen miles, far less distance than the interstate pipeline it feeds into that carries his gas through New Jersey towards White Plains, NY. Yet public documents filed with the Federal Energy Regulatory Commission show it only cost about $.38 – on average -- to move a unit of gas on the interstate system – a fraction of the $2.94 Chesapeake charged Drake to move a unit of gas a vastly shorter distance that February.

"Nobody can tell you why or how come," Drake said. "They pass the buck, they tell you to call this person, and you are lucky if you can even get an answering machine."

Chesapeake declined to explain its charges to Drake or to ProPublica. When a ProPublica reporter visited Chesapeake's headquarters in Oklahoma City, the company's director of external communications sent a message that he was "booked solid" and couldn't talk.

There has long been dispute over how drilling companies calculate royalty payments due landowners.
A 2007 report commissioned from a forensic oil and gas accountant by the National Association of Royalty Owners (NARO) – an organization representing landowners in their dealings with the oil and gas industry – found that almost every company it examined had "used affiliates and subsidiaries to reduce income to royalty owners and taxing authorities."

Nine out of 10 of the top producers in Colorado, Texas, Arkansas and Oklahoma – including ConocoPhillips, Chevron, BP and Chesapeake -- had used subsidiaries to sell their gas for significantly more than the amount they reported to landowners, according to the report. They inflated their expenses, too – at least according to the six companies that provided that level of detail for the report -- charging landowners, on

average, 43 percent more than what they actually paid to handle the gas. (Neither Chevron nor Chesapeake provided information about their expense deductions.)
ConocoPhillips and BP declined to comment for this article. Chevron did not respond to a request for comment.

Other companies have been ensnared in similar controversies. The giant pipeline company, Kinder Morgan, which also declined to speak to ProPublica, has been accused by Montezuma County, Colo., of overstating its transportation and other expenses, and underpaying $2 million in taxes as a result. (Kinder Morgan has paid that bill, but is appealing the decision.) Chevron has faced multiple lawsuits for underpaying royalties and overstating expense deductions because of alleged self-dealing through its affiliate relationships, including a 2009 case the company settled with the U.S. Department of Justice for $45 million.

"Every company has been involved," said Jeffrey Matthews, a vice president and forensic accounting expert at Charles River Associates, a consulting firm, in a lecture to landowners and oil and gas industry accountants in Houston. "If you're dealing with related parties,'' the technical term for the sort of inter-locking subsidiaries created by Chesapeake, "the costs can be double, or triple. You don't know if you are paying for something two to three times over."

Even so, Chesapeake stands out among its peers and is widely known to interpret contracts to match its strategies, executives in the oil and gas industry say.

The company has faced numerous lawsuits – filed by the billionaire Ed Bass, and the city of Fort Worth, among others -- claiming it misrepresented its expenses. Chesapeake has paid hundreds of millions of dollars in settlements and judgments in such cases, including a $7.5 million settlement with Pennsylvania landowners last fall.

One Oklahoma lawsuit, brought by other oil companies that had partnered with Chesapeake, alleged that Chesapeake cheated them out of the final sales price of their gas and artificially inflated its operating expenses, in part by folding in the salaries of high-level management, the cost of seminars they attended, and rent and office expenses for field offices. The suit was settled in late 2004 for $6.5 million. Chesapeake denied any wrongdoing, and the settlement explicitly states that Chesapeake did not agree to "change the practices complained of" in the lawsuit.

“They were making excessive, unwarranted, and unauthorized charges,” said Charles Watson, an Oklahoma attorney involved in the case. “I don’t think it’s mistaken interpretation, I think it’s an intentional accounting maneuver to reduce the amount of money going to the royalty owners and increase the amount of money going to the operator.”

Chesapeake declined to comment about the case.

Joe Drake surveys the well pad Chesapeake Energy built on his property. (Abrahm Lustgarten for Propublica)

For Drake to know how Chesapeake calculated his gathering costs, he has to pay lawyers and accountants to audit the company, or take his grievance to arbitration, a process that would cost him tens of thousands of dollars. In either case, he would need to see the purchase agreements that describe the company’s gas sales in detail. They list far more precisely than Drake’s own statements exactly what costs were incurred, how much gas might have been lost along the way or used by the company for its own purposes, what marketing fees Chesapeake’s subsidiary charged, and the final, real price of the gas.
But Chesapeake isn’t required to share these agreements. They are proprietary.

“When it comes to production expense,” said Charles River’s Matthews, “you’re at their mercy.”

The deals that led to much higher expense charges for Drake and his neighbors involve some sophisticated financial engineering.

Over 12 months, Chesapeake sold off a significant portion of its nationwide system of gathering pipelines in three separate transactions. By December 2012, almost all of the pipes were controlled by a single company – Chesapeake's former affiliate, Access Midstream. Taken together, the sales brought $4.76 billion in cash into Chesapeake's coffers.

The reason behind the moves was simple: All that profligate spending – the Oklahoma City offices, corporate jets and huge executive salaries -- had come at roughly the same time that the price of gas tumbled to historic lows, analysts at several Wall Street investment firms told ProPublica. Chesapeake "desperately needed cash," observed Tony Say, who once headed Chesapeake's Marketing division – the same part of the company that now handles transportation for the gas.

In its securities filings, Chesapeake said that the deals brought the company $1.76 billion more than it had invested to build and maintain its pipelines and the companies that ran them, leaving the impression that the sales were an unqualified boon for Chesapeake.

But a look at an SEC filing by Access Midstream tells a different story: Chesapeake was going to have to give much of that money back.

On the same day as the last of the major sales, Chesapeake signed long-term contracts pledging to pay Access a minimum fee for transporting its gas. In some cases, the fee held no matter what happened to the price of gas, or even how little of it flowed out of Chesapeake's wells.

Chesapeake also promised to connect every new well it drilled to Access's lines for the next 15 years in Ohio's Utica Shale, a potentially lucrative emerging drilling field, and made similar agreements elsewhere.
According to ProPublica projections based on figures disclosed by the companies in late 2013, Chesapeake's commitments would have it paying Access a whopping $800 million each year. Over ten years, the contracts would generate nearly twice as much money as Access had paid Chesapeake for its businesses in the first place.

Pic

In plain words, Chesapeake and a company made up of its old subsidiaries were passing money back-and-forth between each other, in a deal that added little productive capacity but allowed both sides of the transaction to rake in billions of dollars.

Access' chief executive, J. Mike Stice, told a group of investment banking analysts last September that the deals amounted to a "low-risk business model" that "most people haven't understood."

"Nobody really has the access to contractual growth that [Access Midstream] has," Stice said."It doesn't get any better than this."

The SEC filings provide other detail about the ways that the two companies devised to remain inextricably linked, even though Chesapeake has sold the stake it once had in Access.

At the same time it signed its contracts, Access pledged to subcontract a slice of its business back – again -- to companies still owned by Chesapeake. It also agreed to buy industrial equipment used to compress the gas for the pipelines from a company owned by Chesapeake. In essence, Chesapeake would get a rebate on the fees it had guaranteed to Access. Chesapeake never answered questions about whether that rebate was figured in to the price it charged Joe Drake and his neighbors.

In its royalty statements to Joe Drake, Chesapeake says the expenses it had deducted reflect what it costs the company to move his gas. The company has said in public statements about the royalty disagreements in Pennsylvania that it is merely recouping its costs.

But ProPublica's projections drawn from figures previously reported by both companies show that Chesapeake could earn back billions of dollars of the transportation fees it is paying Access over the next 10 years.

There are other ties between the two companies. Access's Chief Executive, Stice, once worked for McClendon as the chief operating officer of one of the companies that used to run the pipelines. Chesapeake's chief financial officer, Dominic del Osso, sits on the board of Access Midstream Partners, and as of 2011, according to SEC records, owned thousands of shares of Access stock.
The relationships raise questions about Chesapeake's assertions that its contracts are arm's-length agreements, and that its expenses reflect its true cost of operating.

“They had a lot of disguised debt,” said Philip Weiss, a chief investment analyst with Baltimore Washington Financial Advisors, who has covered Chesapeake over the years, and was often concerned that the company has understated its financial obligations. In this case, he said, Chesapeake’s expensive contracts with Access might not just be the cost of operating, but another unusual long-term financial obligation that would weigh down the company, but which wouldn’t be reflected in the normal measures of debt. “The use of off-balance-sheet debt is often a way to try to avoid getting as much investor scrutiny.”

For six months Chesapeake declined to answer questions about these discrepancies posed by ProPublica. But in its latest annual financial filings made public just two weeks ago, Chesapeake noted for the first time that it had $36 billion worth of what it called “off-balance-sheet arrangements,” including $17 billion of long-term commitments to buy gathering services. This appears to be the first time the company has acknowledged that it owes more money than what has been identified as debts in previous SEC filings.

In the filings, Chesapeake said that the $17 billion figure didn’t include reimbursement from royalty owners, and that landowners and corporate partners alike “where appropriate, will be responsible for their proportionate share of these costs.”

In an earlier, September 2013 quarterly filing, there were hints of the same activity, but with no disclosure of the salient details to shareholders that might help them understand what was really going on. Chesapeake reported that its expenses related to its pipeline and marketing business roughly doubled in the months after it sold its pipelines, compared to the same period a year earlier, and that its revenues for that part of its business also increased accordingly, covering the new costs. Chesapeake told investors it had cost the company more than $8 to transport a cubic foot of gas or its oil equivalent – an astronomical amount unheard of in the energy industry.

“Something is wrong with this calculation,” said Fadel Gheit, a seasoned industry analyst for the investment firm Oppenheimer, who estimated the figure was off by a decimal point before later confirming that it matched the numbers Chesapeake had reported to the SEC. “It can’t be.”

In fact, none of the financial analysts who cover Chesapeake that ProPublica spoke with could explain the explosion in Chesapeake’s marketing and transportation revenues and expenses using oil sales alone.

“The change in marketing, gathering, compression revenue and expense is staggering,” wrote Kevin Kaiser, a financial analyst with Hedgeye, a private equity group in New York, in an email to ProPublica.

Neither Chesapeake's investor relations group, nor its media staff would comment on whether the deals amounted to disguised debt that landowners would repay. In interviews, one former Chesapeake employee with knowledge of the company's operations dismissed the notion that Chesapeake was essentially paying back an off-balance-sheet loan by paying unusually high fees for use of the pipelines.

"The timing supports that --- that Chesapeake got paid a lot of money and the gathering fees get paid back over time, and it looks like a loan arrangement," said the former employee. "But to jump to the conclusion that the whole thing is a sham and a means by which they are going to defraud royalty owners is not true."
Only in its latest filing at the end of February, after months of queries from ProPublica, did Chesapeake add a note – two sentences in 299 pages – stating that its contracts with Access and other companies played into the rising figures. But the company did not specify how much.

And to the extent that the real costs of gathering and transporting gas can be gleaned from securities reports and Joe Drake's own statements, there's still a big gap between what Chesapeake reports it paid out, and what Access reports it received for gathering services.

In the mean time, one thing is for sure: all the escalating costs, side deals, and unexplained debt aside, Access is making more money than ever, while Chesapeake – so recently fighting to stay alive -- has emerged from its troubles and is turning a profit.

Joe Drake, on the other hand, is almost back to where he began.

He recently cancelled a fishing trip to Canada and doubled back on the question of how to make a living from the farm. With his livestock gone he will now focus on growing and bundling hay, which he will sell to other farms so they can feed their animals. The natural gas boom has become little more than a sideshow.

"We are surviving," he said. "But we learned that a good old handshake don't cut it anymore."

4.21 2014-04-01 _ In Fracking Fight, a Worry About How Best to Measure Health Threats

(Mladen Antonov/AFP/Getty Images)

There are more than 6,000 active gas wells in Pennsylvania. And every week, those drilling sites generate scores of complaints from the state's residents, including many about terrible odors and contaminated water.

How the Pennsylvania Department of Environmental Protection handles those complaints has worsened the already raw and angry divide between fearful residents and the state regulators charged with overseeing the burgeoning gas drilling industry.

For instance, the agency's own manual for dealing with complaints is explicit about what to do if someone reports concerns about a noxious odor, but is not at that very moment experiencing the smell: "DO NOT REGISTER THE COMPLAINT."

When a resident does report a real-time alarm about the air quality in or around their home, the agency typically has two weeks to conduct an investigation. If no odor is detected when investigators arrive on the scene, the case is closed.

“The time that it takes them to respond is something people are concerned about,” said Matt Walker, a community outreach director for the Clean Air Council in Pennsylvania, an environmental advocacy organization. Waiting a few days to two weeks to respond to odor complaints, he said, is “way too long.” George Jugovic, who served as a regional director for the DEP until 2012, agrees. Jugovic said the department is only set up to respond quickly to potential emergencies.

“It’s a problem,” said Jugovic, who since leaving the department has served as counsel to a local environmental group.

Rebecca Roter said she experienced the problem first hand last year. On a cool April evening in 2013, Roter said she was cooking dinner in her Susquehanna County home when a “nauseating” smell overwhelmed her. Roter said she walked out to her front porch, pulled her gray hoodie over her nose and mouth and quickly drove her car to the site of a nearby gas well being fracked.

Roter said she saw plumes of dust rising into the air. That evening, Roter said she wrote to the DEP, recounting the events of the day and requesting that they send out a field agent to follow up. Four days later, the agency sent out an investigator.

The DEP later notified Roter in writing that the investigator had found “nothing out of line” and that it had concluded that “the operation appeared to be conducted as per standard procedure.”

Roter said she is convinced the investigator simply didn’t detect any smell when he responded 96 hours after her report. The odor has recurred repeatedly in the months since, she said, and she has no idea how alarmed to be.

The concerns of residents like Roter are not likely to be eased by a study published today in Reviews on Environmental Health, a peer reviewed journal. The study, researchers say, confirms what they have long suspected about natural gas operations — that emission levels from these sites spike drastically over short periods of time, making it hard to assess the true threat to people’s health.

Researchers at the Southwest Pennsylvania Environmental Health Project collected real-time readings of particulate matter — soot, dust and chemicals — in 14 homes in Washington County, a heavily drilled part of the state. They found repeated episodes during which measures of contaminated dust rose sharply, to dangerous levels in the course of a day.

David Brown, the lead researcher on the study, said that a person in such circumstances could get what amounted to a full day's exposure in half an hour.

The American Petroleum Institute did not respond to repeated requests for comment. The Pennsylvania Independent Oil and Gas Association declined to comment on the Environmental Health Project's study but said that the oil and gas industry is "heavily regulated" and that the association's member companies "strive to comply with numerous federal and state air quality related rules, regulations, and reporting requirements."

Still, residents like Roter, who has over 20 gas wells within a mile of her house, fear that the exposure to contaminants could quickly add up. It's one of the reasons, she says, she is frustrated by the DEP's response to her complaints.

DEP spokeswoman Lisa Kasianowitz defended the department's performance on complaint investigations.
"DEP has been prompt and responsive in regards to air quality concerns surrounding the natural gas industry," she said in response to questions from ProPublica. She added that the department had recently toughened oversight of the industry, and that oil and gas companies were no longer exempt from complying with basic permitting requirements.

Kasianowitz provided ProPublica with some recent statistics on complaints and inspections, and she promised to make department's officials available to be interviewed. Later, after ProPublica filed a freedom of information request seeking more detailed information on dozens of the department's investigations, Kasianowitz said the officials could not be interviewed.

The information provided by the DEP shows that between 2011 and 2014, the department received over 2,000 complaints about oil and natural gas operations. Water quality issues featured prominently in the list of complaints. The DEP also registered 110 of the complaints as odor issues.

In Southwestern Pennsylvania, a corner of the state that has seen extensive fracking operations, there were 617 registered complaints over those years, including 47 involving troubling odors.

In one-third of the cases that were investigated, inspectors reported that no odors were detected at the time of inspection and closed the case. Inspectors typically visited residents within a week of filing the complaint.

In only a handful of cases did the inspectors detect odors during their visit and follow up by citing the company involved. The citations, known as a Notice of Violation, required the operators to correct the problem, but did not carry fines.

ProPublica's request for more details on the investigations and violations is still pending.

John Quigley, a former director of the Pennsylvania Department of Conservation and Natural Resources, said the need for greater transparency in the oversight of the fracking industry was real and urgent.

In 2007, Pennsylvania produced close to 10 billion cubic feet of gas from the Marcellus formation. By 2012, that number had grown to over two trillion cubic feet. With this dramatic increase in gas production, concerns about environmental pollution and public health have risen sharply and the DEP has become a target for anger among worried residents.

Activists and environmental groups have accused the agency of being overly deferential to the gas industry, and defensive and slow moving in its dealings with the public.

"It was very top down, very secretive and paranoid about who the enemies were," said Jugovic, the former agency official, who left the department when Corbett succeeded Rendell as governor. "The control on information was significant."

Earlier this month, Chris Abruzzo, the current head of the DEP, publicly acknowledged criticism about the agency's transparency issues and said he wanted to change public perception of the agency.

Critics of the state's dealings with the gas industry have long highlighted the history of financial ties between the industry and state officials, including former Democratic Gov. Ed Rendell and current Republican Gov. Tom Corbett.

Last year the Public Accountability Initiative, a nonprofit watchdog organization focused on the intersection of government and business, released a report on what it called Pennsylvania's revolving door between the government and the gas industry. It concluded that at least 20 DEP employees have also held energy industry jobs either before or after their agency jobs.

Gov. Corbett's office did not respond to a request for comment.

ProPublica obtained an internal complaints manual used by the DEP to maintain a consistent approach in dealing with environmental complaints. The manual directs staff to assign routine air quality issues a priority level of 2. The category comprises complaints that are "serious but not likely to escalate within 7-10 days but pose an existing or potential adverse impact on the environment or public health."

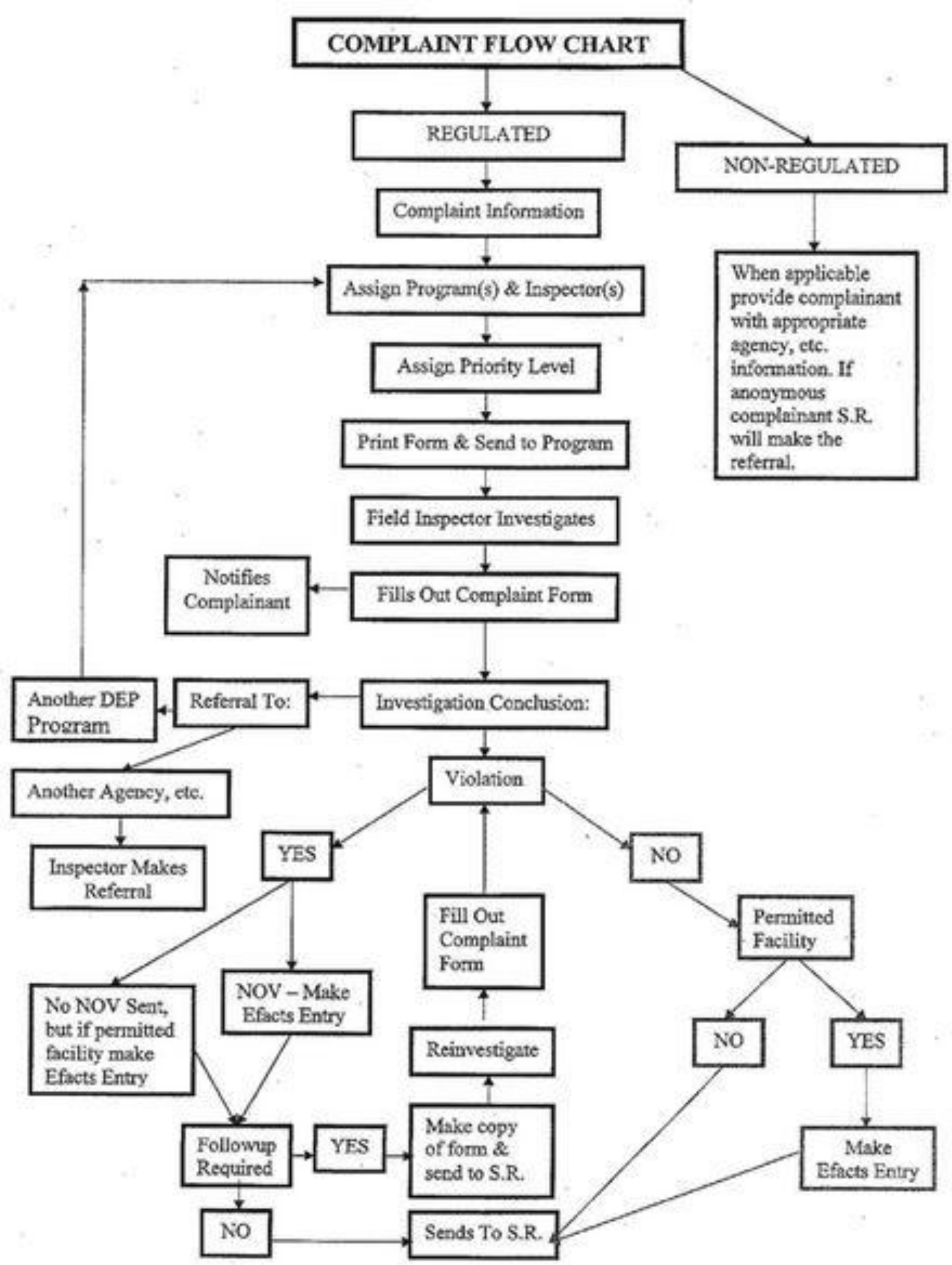
According to the internal complaint manual, DEP complaint coordinators, who answer calls on regional complaint hotlines, are responsible for assigning response priority levels.

In 2012, the Clean Air Council, which has been tracking the DEP's enforcement of regulations related to air quality, sent a letter to the U.S. Environmental Protection Agency, complaining about the alleged shortcomings of Pennsylvania's oversight.

The council said it had been contacted by many residents who asserted that complaints they had filed with the DEP had never been fully investigated. In some cases, the council claimed, residents had said the DEP's complaint hotline had not been working when they called.

"People have been told things like 'stop calling' and 'if you're air is bad, then maybe you shouldn't go outside,'" said Walker, the council's community outreach director.

Kasianowitz did not respond to ProPublica's questions about allegations of inadequate or unprofessional behavior by agency staff.



Gas drilling operations include several processes that release toxic chemicals into the air. The type and level of chemicals released varies from hour to hour depending on the type of activity taking place on the well pad.

Despite this, researchers and regulators seeking to assess the health threat of fracking operations have typically used measurement devices that capture air emissions over longer periods of time, often 24 hours.

These levels are then, in many cases, compared to the EPA's National Ambient Air Quality Standards, which were created over 40 years ago at a time when large, 24-hour-a-day sources of pollution such as coal fire plants and steel mills were dominant.

"You can't use 24-hour standards if the health effect occurs within a few minutes," said Brown, the lead author of the study released Friday.

The question of whether episodic bursts of contaminated air from fracking could pose an unappreciated but real health menace was first explored in West Virginia in 2010.

West Virginia's Department of Environmental Protection asked Michael McCawley, then a professor at West Virginia University's Health Sciences Center, to study air emissions from fracking operations in the state. McCawley found the contaminants he detected at fracking sites fluctuated over a wide range.

Those findings mirror those in the Pennsylvania study published on Tuesday.

Research has shown that fracking operations can release an array of toxic chemicals — some carcinogenic, others capable, at significant enough levels, of causing serious neurological and respiratory damage. The worry, Brown says, is that these chemicals are attached to the microscopic dust particles that he detected and can reach the bloodstream after being inhaled.

McCawley and Brown say that the wide fluctuations that they're picking up on are also attributable to operators not using the best available technology to limit possibly harmful emissions.

State and federal regulations, for instance, do not require operators to use equipment that would capture all emissions during drilling. Often, gases are vented or flared into the air. The regulations also don't consider activities, like diesel truck traffic, that degrade air quality at the fracking site.

"The law requires best technology," said McCawley, and the data, he says, is telling us that the gas drilling industry is "not working according to the strict definition of the law."

Correction: *An earlier version of this story mistakenly said that the Marcellus shale formation had produced two million cubic feet of gas by 2012. In fact, it had produced two trillion cubic feet of gas.*

4.22 2014-05-13 _ In Fracking Hotbed, a Muted Approach to Regulation

A brine injection well seen in Youngstown, Ohio. (Amy Sancetta/AP Photo)

by Naveena Sadasivam *ProPublica, May 13, 2014, 2:48 p.m.*

In Ohio, where gas drilling is booming and toxic waste abundant, legislators acted modestly to address concerns about public safety.

Ohio annually processes thousands of tons of radioactive waste from hydraulic-fracturing, sending it through treatment facilities, injecting it into its old and unused gas wells and dumping it in landfills. Historically, the handling and disposal of that waste was barely regulated, with few requirements for how its potential contamination would be gauged, or how and where it could be transported and stored.

With the business of fracking waste only growing, legislators in 2013 had the chance to decide how best to monitor the state's vast amounts of toxic material, much of it being trucked into Ohio from neighboring states.

But despite calls to require that the waste be rigorously tested for contamination, Gov. John Kasich and the state legislature signed off on measures that require just a fraction of the waste to be subjected to such oversight. The great majority of the byproducts creating during the drilling process – the water and rock unearthed – still do not have to be tested at all.

As well, the legislature, lobbied by the fracking industry, undid the governor's bid to have the testing of the waste done by the state's Department of Health — the agency acknowledged by many to possess the most expertise with radioactive material. The testing is now the responsibility of the Department of Natural Resources, the agency that oversees the permitting and inspection of oil and gas drilling sites, but that has no track record for dealing with radioactive waste.

The legislators acted with little in the way of public debate, and the new regulations they adopted appeared deep inside a 4,000-page state budget bill. As a result, both the measures first proposed by Kasich and those ultimately signed into law have infuriated environmentalists and residents with concerns about the risks of fracking in their state.

A ProPublica review of the legislature's actions shows that just a handful of parties testified before the oversight committees charged with examining the pros and cons of the proposed regulations. And interviews with legislative staffers make clear that the final language of the regulations, including changes that scaled back two measures proposed by the governor, was inserted into the budget bill at the last minute.

And so today, to the surprise of much of the public as well as some elected officials, Ohio's oversight of fracking waste remains much as it had been – limited and controversial.

"It has the potential to leave a toxic legacy that could turn much of Ohio into potential superfund sites," said Alison Auciello of the Food and Water Watch, an environmental advocacy organization.

Tom Stewart, vice president of the Ohio Oil and Gas Association, said existing regulations made mandatory testing of fracking waste unnecessary and said his group had pushed to limit the Department of Health's role because it would have created bureaucratic problems rather than effective monitoring.

The state's oil and gas interests supports "regulation that directly enhances protection of the public interest while allowing industry to efficiently do its job," he said. "We do not support regulation that is designed more to placate people or somehow make them feel better."

Regulations for the disposal of fracking waste vary from state to state. In some, like Texas, regulation is virtually non-existent. But others have taken more aggressive measures to safeguard the public. For instance, North Dakota and Pennsylvania have agreed to identify and quantify, through formal testing, the radioactive threat and plan to adopt protections accordingly. Already, they have installed alarms in landfills to check if the contaminated waste being received violates the state limits already in place. And in West Virginia, legislators enacted a law requiring the construction of separate, lined pits for the storage of radioactive fracking waste.

Oil and gas drilling is big business in Ohio, responsible for tens of thousands of jobs and billions of dollars in investments by companies eager to mine the state's natural resources. An economic study conducted by industry groups in 2011 forecasted that the business would add over 200,000 jobs in coming years. Kasich has declared Ohio an eager partner with the industry.

The environmental challenges produced by the industry in Ohio fall into two categories: the liquid waste created by hydraulic-fracturing, much of which is now stored by re-injecting it into the earth; and the solid waste that is now piling up in the state's landfills.

The public in Ohio has become most knowledgeable and concerned about the handling of liquid waste. There has been growing concern that the fracking process has provoked earthquakes, creating cracks through which the radioactive water put back in the earth could contaminate the local groundwater.
State officials have said they are studying the threat of liquid waste, but the measures adopted in last year's budget bill did next to nothing to address the potential threat.

There is little doubt among environmentalists and others concerned with safety that the debate over what to do with the fracking waste has been colored by the state's interest in promoting the industry's growth. Analysts and others say being able to easily dump waste within Ohio spares drilling operators one of their greatest expenses – trucking the waste elsewhere.

Kasich's office did not respond to repeated requests for comment about the new regulations and how they came to be. Officials with the Ohio Senate majority caucus, which revised and ultimately pushed through the 2013 regulations, also would not comment.

Environmentalists in Ohio assert that no meaningful regulation of the industry can be achieved without real public debate, including input from researchers and scientists who have been studying the health risks of radioactive waste for years.

"When you let politics rule in the face of scientific determination, it's an unconscionable position to take," Julie Weatherington-Rice, an adjunct professor in the Department of Food, Agricultural and Biological Engineering at Ohio State University, said of the limited changes in regulatory oversight. "In the process of doing that they've put the population of Ohio at risk."

Radioactive waste is produced at almost every step of the natural gas extraction process that has come to be known as fracking. This is true in part because the very shale formations that drillers are trying to access contain radioactive metals. As operators drill down to the gas reserves, they bring some of those metals back to the surface.

In some cases, the metals dissolve into the water used to frack the well, contaminating it. In other cases, the metals are present in the bits of rock and soil – called drill cuttings – that operators break up while drilling. In order to bring these cuttings back up to the surface and to keep the drilling machinery cool, operators use drilling mud, a viscous fluid with high levels of radium and a host of other radioactive elements.

None of this is new. Oil and gas fields have always produced radioactive waste. But the fracking boom has increased the intensity of drilling and, as a result, radioactive materials are being unearthed faster and in larger quantities. Also, operators are accessing newer shale reserves that the U.S. Geological Survey has found to produce higher levels of radium than conventional oil and gas reserves.

In recent years, with Ohio elected officials promoting the fracking industry and neighboring states more vigorously regulating the disposal of fracking waste, Ohio has come to be a dumping ground. In 2013, for instance, three municipal landfills in Ohio received over 100,000 tons of solid fracking waste, according to FracTracker, an organization that collects data on the fracking industry. Those very facilities handled no more than 15,000 tons in 2011.

Increasing amounts of the fracking waste disposed of in Ohio comes from Pennsylvania. In 2011, Pennsylvania adopted several measures to curtail and control the disposal of fracking waste inside its borders. In 2013, the Pennsylvania Department of Environmental Protection estimated that 100,000 tons of drill cuttings from fracking sites in Pennsylvania ended up in Ohio's landfills.

Ohio is not the only state struggling to deal with the tons of radioactive waste coming out of drilling sites. In North Dakota, a state that has seen a tremendous growth in oil production in recent years, officials have been finding heaps of filter socks – nets used to strain radioactive wastewater – dumped illegally in abandoned gas stations and alongside roads.

But Ohio's growing popularity as something of a go-to destination for fracking waste has ignited widespread concern in the state about better protecting the public and toughening regulations.

In 2012, the Ohio Department of Health, facing increasing pressure from concerned citizens and environmental groups, conducted tests to investigate the risk of radioactive waste. The department measured levels of radioactivity in the sand used while fracking, the water that is brought back up after the process, the pieces of rock and minerals from the well, and the fluid used to drill the well.

The chemical mixture used to drill the well — the drilling mud — tested positive for radium at levels over 100 times the safety limits for disposal at a local landfill. If federal law had applied to it, the waste would have to be trucked to one of the nation's handful of low-level radioactive waste sites.

Every two years, Ohio passes a sprawling budget bill that, all too easily, can be a vehicle for adopting controversial policy changes without much public discussion or transparency. That's what happened last year when Kasich and the Republican-controlled State Senate decided to cram revamped fracking regulations into the giant spending bill.

The governor first sought to include a half dozen measures to address concerns over how to deal with the growing amounts of waste being generated or deposited in Ohio.

The measures, among other things, required that the "drilling mud" used in the fracking process be tested for contamination. They also required that the testing be done by the Department of Health, which had long overseen the handling of radioactive waste and other materials in the nuclear energy and hospital industries. But the measures also exempted the lion's share of the waste generated by the drilling process. The exempted waste included the solidified rock and mud that, once in landfills, was often exposed to rain and snow over long periods of time. Researchers say that if there are leaks or tears in a landfill's liner, the groundwater used by the local community can become contaminated.

The implications of the governor's proposed provisions struck some as warranting much greater debate and scrutiny.

"There was some discussion [in the House] that because it was such a substantial piece of policy, it might be dealt with better in a stand-alone bill," said one staffer with the Ohio House of Representatives, who spoke anonymously for fear of straining relations with his Republican colleagues.

Environmentalists in the state agreed, arguing that the governor's proposed provisions did next to nothing to improve the rigor of oversight, and that testimony from experts in public health and the science of fracking was badly needed. Ohio's obligation, they asserted, was all the greater because, at the federal level, radioactive waste from fracking has been exempted from several regulatory requirements that are intended to protect the environment. As a result, oversight of radioactive waste has been mostly left to state governments.

Fracking-related state legislation usually generates a lot of media attention and public participation, but that did not happen on the radioactive waste provisions tucked into the Ohio budget bill. Only four parties testified on the proposals: the Ohio Environmental Council, the Ohio Sierra Club, Food and Water Watch and the Ohio Oil and Gas Association.

Veterans of Ohio's fracking fights said that had the proposals been aired as part of a separate bill, and not as one aspect of a massive, highly technical budget bill, the debate likely would have been far more robust. It could have included everybody from scientists to landowners to citizens who already feel they have had their health harmed.

In the relative quiet, then, the Oil and Gas Association won on one critical issue. The industry objected to the governor's notion that the Health Department conduct any testing of fracking waste.

Records show that industry officials lobbied aggressively to keep all responsibility for fracking waste with the Department of Natural Resources. The natural resources agency, officials argued, already regulated much of the state oil and gas. Splitting oversight responsibility, the industry argued, would be wasteful and ineffective.

James Aslanides, president of MFC Drilling, testified on behalf of the oil and gas industryduring a brief, initial hearing before a House committee considering the governor's proposals. He contended that giving the Health Department a role in oversight would "blur the line between regulatory agencies."

"There is no problem," he testified. "This is the classic regulatory solution looking for a problem to solve."
Environmentalists were livid. The Ohio Department of Health has a long history of regulating the use and disposal of radioactive material in the state. The department has an agreement with the U.S Nuclear Regulatory Commission to license and inspect nuclear facilities, and any potentially radioactive material thatnuclear power plants produce has to be permitted for disposal by the Health Department.

To many, it made sense to have the department be charged with deciding what fracking material would have to be tested, and how it would be done.

"The last time I checked, there was no one at the Department of Natural Resources who knows squat about radiation," said Teresa Mills, an Ohio organizer at the Center for Health, Environment and Justice, an advocacy organization based in Virginia.

Officials with the Department of Natural Resources did not respond to a request to identify any employee with experience in dealing with radiation.

At first, it seemed the industry's efforts had failed. The House committee, clearly convinced the measures required their own bill and a fuller public debate, removed all of the governor's proposed regulatory measures.

But the measures resurfaced in the State Senate, and, on the eve of a full legislative vote on the budget bill, were reinserted in the law. The Senate's provisions included granting the industry one of its wishes: any testing of fracking waste would be the responsibility of the Natural Resources Department.

On June 30, 2013, with the House having opted not to protest the Senate's reintroduction of the measures, the bill was signed into law by Kasich.

Stewart, the industry association official, said the provisions were responsibly calibrated.

Many citizen activists, researchers and an array of environmental groups are not persuaded.

"It would be one thing if this was a hundred years ago and we didn't know better," said Weatherington-Rice, the Ohio State professor. "But we know better. That's what is aggravating about this.

"They're putting people at risk and they know better."

4.23 2014-07-02 _ Aggressive Tactic on the Fracking Front

Left: Residents living close to this gas well pad in Washington County, Pennsylvania have complained of poor air quality and noise.
(Courtesy of Robert M. Donnan)

Right: Muriel Spencer, who lives about 500 feet from EQT Corp.'s gas well, says she has no complaints about the company's operations.
(Courtesy of Robert M. Donnan)

A Pennsylvania gas company offers residents cash to buy protection from any claims of harm.

by Naveena Sadasivam *ProPublica, July 2, 2014, 10:01 a.m.*

For the last eight years, Pennsylvania has been riding the natural gas boom, with companies drilling and fracking thousands of wells across the state. And in a little corner of Washington County, some 20 miles outside of Pittsburgh, EQT Corporation has been busy – drilling close to a dozen new wells on one site.

It didn't take long for the residents of Finleyville who lived near the fracking operations to complain – about the noise and air quality, and what they regarded as threats to their health and quality of life. Initially, EQT, one of the largest producers of natural gas in Pennsylvania, tried to allay concerns with promises of noise studies and offers of vouchers so residents could stay in hotels to avoid the noise and fumes.

But then, in what experts say was a rare tactic, the company got more aggressive: it offered all of the households along Cardox Road $50,000 in cash if they would agree to release the company from any legal liability, for current operations as well as those to be carried out in the future. It covered potential health problems and property damage, and gave the company blanket protection from any kind of claim over noise, dust, light, smoke, odors, fumes, soot, air pollution or vibrations.

The agreement also defined the company's operations as not only including drilling activity but the construction of pipelines, power lines, roads, tanks, ponds, pits, compressor stations, houses and buildings.
"The release is so incredibly broad and such a laundry list," said Doug Clark, a gas lease attorney in Pennsylvania who mainly represents landowners. "You're releasing for everything including activity that hasn't even occurred yet. It's crazy."

Linda Robertson, a spokeswoman for EQT, said in a statement that the company had worked hard and conscientiously to address the concerns of the residents. She said consultants had been hired, data collected on noise and health matters, and that independent analysis had shown the company was in compliance with noise and air quality requirements. She would not comment in detail on the financial offers.

"When landowner and leaseholder concerns arise, it is a standard practice for EQT personnel to work diligently to listen to and understand their concerns, particularly those related to the temporary inconveniences of living near a production site," Robertson said. "Regarding the neighbors on Cardox Road, the majority of whom are leaseholders, we have been in regular and ongoing communications with residents and local officials to address and resolve questions as they arise."

Hydraulic fracturing – or fracking – has provoked a litany of health and environmental concerns since it gained popularity within the last decade. Many environmentalists and public health experts contend that the practice can pollute groundwater aquifers, drastically reduce air quality and endanger the health of residents living near wells.

Over the years, the industry has vehemently denied that its work is a threat, and has often pointed to a lack of conclusive proof that gas drilling operations are to blame for any harmful health or safety issues. The industry has undertaken an array of efforts to quell these worries and preserve its business — lobbying state legislators, conducting its own scientific studies and occasionally settling quietly out of court with landowners who have threatened to sue.

The liability agreements EQT has used in Finleyville — they are often known as nuisance easements — have been used in other circumstances. Residents living close to airports, for instance, are often offered such easements as compensation for having to bear with the noise, vibrations and fumes from air traffic. Property owners close to landfills and wind farms may also sign similar agreements.
But experts say such easements are rare in the oil and gas industry.

"This is only the second time I've seen one," said Clark, the Pennsylvania attorney. "They're absolutely not common at all."

Clark says it is unlikely that companies will start handing out such agreements en masse, saying doing so could decrease landowners' confidence about the safety of the company's operations and their personal health.

"People are going to say the gas companies must be concerned about air pollution because they're offering these easements," said Clark. "Everybody's going to get suspicious."

Earlier this year, a couple in Texas was awarded $3 million in a lawsuit against a gas drilling company. The couple alleged that the company's operations had affected their health, decreased their property value and forced them to move away. The case was one of the first successful lawsuits alleging that air pollution from gas drilling activity caused health issues.

Experts say that verdict and others like it have emboldened landowners to take their claims to court. Nuisance easements may be one way to ensure that the company can easily block landowners from claiming damages.

Apart from drilling and fracking wells, EQT also builds and operates the infrastructure — pipelines and compressor stations — necessary to move natural gas to market. Its operations are headquartered in Pennsylvania but it also owns wells in Kentucky and West Virginia.

In 2008, landowners in Finleyville signed a gas lease for drilling with Chesapeake Energy. The company only drilled one well, but last year it sold its leases to EQT, which has since drilled 11 additional wells.
So far the company's strategy to reduce its liabilities has worked with some landowners.

Muriel Spencer, whose house is about 500 feet from the drilling, took the money. She said she did not consult with a lawyer, but had asked the company to put a five-year time frame around the release. The initial contract released the company from liabilities indefinitely.

"I cannot complain about the drilling to this point," Spencer said, adding that EQT "has been nothing but fair with me."

The company's spokeswoman would not comment on how many landowners EQT approached with the proposed agreements, but said that "approximately 85% of the residents" had signed them.

An initial version of the proposed standard agreement listed 30 Finleyville residents and required that they all sign the agreements in order to receive the $50,000. When the residents refused, EQT modified the agreement such that the compensation was not contingent on all landowners signing it.

ProPublica found that at least four of the 30 residents have agreed to some version of the initial agreement that EQT proposed and have received $50,000 in exchange. It is unclear what changes were made to the agreement during negotiations.

Robertson, the company spokeswoman, said in her statement that "any changes made to the agreements during negotiations were based on requests directly from the resident, and/or their attorney."
But some of the residents have refused to negotiate with the company.

"I was insulted," said Gary Baumgardner, who was approached by EQT with the offer in January. "We're being pushed out of our home and they want to insult us with this offer."

Baumgardner says his house is like an amphitheater, constantly vibrating from the drilling. At times the noise gets up to 75 decibels, equivalent to a running vacuum cleaner, he said. Earlier this year, EQT Corp. put up a sound barrier to limit the noise, but Baumgardner says it has made little difference to his quality of life.

"We took the pictures down in the bedroom because they still vibrate at night," he said.

Baumgardner says he has had to leave his house at least three times so far because the gas fumes from the well site were too much to bear. A local health group has installed air quality monitors in his home and several of his neighbors. Last year when the one of the monitors began flashing red, his daughter, pregnant at the time, fled the house. She has since moved away after her doctor advised her not to live close to a drilling site.

"Our house is most often not livable," said Baumgardner. EQT's response to his complaints, he said, has been "constant dismissals, excuses, delays and broken promises."

Robertson would not respond to Baumgardner's specific assertions. She did point to several mitigation efforts she said the company had taken, including the sound wall, but also involving switching to quieter machinery and applying for permits to transport water via pipes instead of trucks.

Baumgardner believes the nuisance easement he was offered is a part of the industry's tactic to silence landowners.

"Throughout the last several months, an EQT regional land manager, one of our community advisers, and our community relations manager have all been engaged in phone calls and personal meetings with residents, attended township meetings, and visited the production site on multiple occasions to identify and confirm the reported issues, if any," Robertson's statement said.

"The easements are part of our overall consistent and ongoing effort to address leaseholder concerns."

4.24 2014-07-18 _ California Halts Injection of Fracking Waste, Warning it May Be Contaminating Aquifers

The potential impact of waste from oil and gas drilling — including hydraulic fracturing on drinking water has been an issue in Texas, Wyoming and, with great urgency, in California this month. Here, a jar of fracking water waste is displayed at a recycling site in Midland, Texas. (Pat Sullivan/AP Photo)

State's drought has forced farmers to rely on groundwater, even as California aquifers have been intentionally polluted due to exemptions for oil industry.

by Abrahm Lustgarten *ProPublica, July 18, 2014, 11:50 a.m.*

California officials have ordered an emergency shut-down of 11 oil and gas waste injection sites and a review more than 100 others in the state's drought-wracked Central Valley out of fear that companies may have been pumping fracking fluids and other toxic waste into drinking water aquifers there.

The state's Division of Oil and Gas and Geothermal Resources on July 7 issued cease and desist orders to seven energy companies warning that they may be injecting their waste into aquifers that could be a source of drinking water, and stating that their waste disposal "poses danger to life, health, property, and natural resources." The orders were first reported by the Bakersfield Californian, and the state has confirmed with ProPublica that its investigation is expanding to look at additional wells.

The action comes as California's agriculture industry copes with a drought crisis that has emptied reservoirs and cost the state $2.2 billion this year alone. The lack of water has forced farmers across the state to supplement their water supply from underground aquifers, according to a study released this week by the University of California Davis.

The problem is that at least 100 of the state's aquifers were presumed to be useless for drinking and farming because the water was either of poor quality, or too deep underground to easily access. Years ago, the state exempted them from environmental protection and allowed the oil and gas industry to intentionally pollute them. But not all aquifers are exempted, and the system amounts to a patchwork of protected and unprotected water resources deep underground. Now, according to the cease and desist orders issued by the state, it appears that at least seven injection wells are likely pumping waste into fresh water aquifers protected by the law, and not other aquifers sacrificed by the state long ago.

"The aquifers in question with respect to the orders that have been issued are not exempt," said Ed Wilson, a spokesperson for the California Department of Conservation in an email.

A 2012 ProPublica investigation of more than 700,000 injection wells across the country found that wells were often poorly regulated and experienced high rates of failure, outcomes that were likely polluting underground water supplies that are supposed to be protected by federal law. That investigation also disclosed a little-known program overseen by the U.S. Environmental Protection Agency that exempted more than 1,000 other drinking water aquifers from any sort of pollution protection at all, many of them in California.

Those are the aquifers at issue today. The exempted aquifers, according to documents the state filed with the U.S. EPA in 1981 and obtained by ProPublica, were poorly defined and ambiguously outlined. They were often identified by hand-drawn lines on a map, making it difficult to know today exactly which bodies of water were supposed to be protected, and by which aspects of the governing laws. Those exemptions and documents were signed by California Gov. Jerry Brown, who also was governor in 1981.

State officials emphasized to ProPublica that they will now order water testing and monitoring at the injection well sites in question. To date, they said, they have not yet found any of the more regulated aquifers to have been contaminated.

"We do not have any direct evidence any drinking water has been affected," wrote Steve Bohlen, the state oil and gas supervisor, in a statement to ProPublica.

Bohlen said his office was acting "out of an abundance of caution," and a spokesperson said that the state became aware of the problems through a review of facilities it was conducting according to California's fracking law passed late last year, which required the state to study fracking impacts and adopt regulations to address its risks, presumably including underground disposal.

California officials have long been under fire for their injection well practices, a waste disposal program that the state runs according to federal law and under a sort of license — called "primacy" — given to it by the EPA.

For one, experts say that aquifers the states and the EPA once thought would never be needed may soon become important sources of water as the climate changes and technology reduces the cost of pumping it from deep underground and treating it for consumption. Indeed, towns in Wyoming and Texas — two states also suffering long-term droughts — are pumping, treating, then delivering drinking water to taps from aquifers which would be considered unusable under California state regulations governing the oil and gas industry.

In June 2011, the EPA conducted a review of other aspects of California's injection well program and found enforcement, testing and oversight problems so significant that the agency demanded California improve its regulations and warned that the state's authority could be revoked.

Among the issues, California and the federal government disagree about what type of water is worth protecting in the first place, with California law only protecting a fraction of the waters that the federal Safe Drinking Water Act requires.

The EPA's report, commissioned from outside consultants, also said that California regulators routinely failed to adequately examine the geology around an injection well to ensure that fluids pumped into it would not leak underground and contaminate drinking water aquifers. The report found that state inspectors often allowed injection at pressures that exceeded the capabilities of the wells and thus risked cracking the surrounding rock and spreading contaminants. Several accidents in recent years in California involved injected waste or injected steam leaking back out of abandoned wells, or blowing out of the ground and creating sinkholes, including one 2011 incident that killed an oil worker.

The exemptions and other failings, said Damon Nagami, a senior attorney with the Natural Resources Defense Council in an email, are "especially disturbing" in a state that has been keenly aware of severe water constraints for more than a century and is now suffering from a crippling drought. "Our drinking water sources must be protected and preserved for the precious resources they are, not sacrificed as a garbage dump for the oil and gas industry."

Still, three years after the EPA's report, California has not yet completed its review of its underground injection program, according to state officials. The scrutiny of the wells surrounding Bakersfield may be the start.

4.25 2014-07-22 _ New York State of Fracking - A ProPublica Explainer

New York currently has a moratorium on fracking, but communities in the state have banded together and are using local ordinances to permanently ban the practice within their town boundaries. (Spencer Platt/Getty Images)

Court cases. A governor's moratorium. Pending health study.
A quick guide to the state of fracking in New York.

by Naveena Sadasivam *ProPublica, July 22, 2014, 10:45 a.m.*

New York is one of a handful of states around the country that currently has at least temporarily halted fracking. Since 2008, when the state was first confronted with interest in gas drilling and hydraulic fracturing by energy companies, towns have banned the practice, the state has undertaken environmental and health studies, courts have issued rulings on fracking and concerns have been raised about the state's pristine water supply.

Here's a rundown of what you need to know about the current status of fracking in New York, the protections available to the state's major watershed and the implications of the most recent court ruling for local municipalities.

So, does NY have a moratorium on fracking?

Yes, New York currently has a moratorium in place. But the current moratorium, as opposed to a legislative moratorium, is not codified into law and does not have an expiration date. In 2010, former Gov. David Paterson vetoed a bill intended to rein in natural gas drilling and instead issued an executive order instituting a six-month moratorium on high volume hydraulic fracturing, or fracking as it is more commonly known. That moratorium, contingent on the completion of a review of the environmental impacts of fracking by the state environmental agency, is still in place.

In the last six years, two drafts of environmental impact reviews and two sets of draft regulations have been prepared. After the Department of Environmental Conservation released its 2012 report, it asked the Department of Health to review information related to the public health effects from natural gas drilling. That review is currently underway.

Environmental groups have been pushing for a moratorium with a time frame locked in or a moratorium enacted through the legislature, which they say would legally guarantee the moratorium will stay in place and provide time for the additional health studies currently being conducted by researchers around the country to be completed. In the last four years, at least three bills have been proposed to codify the moratorium into law but they have all failed to pass the Senate and reach the Governor's desk.

When will Gov. Cuomo decide to permit or ban fracking?

Nobody knows. Recently, Joeseph Martens, the state's environmental conservation commissioner, indicated that he won't issue fracking permits before April 2015, delaying the decision until after Cuomo faces re-election. Earlier this year, health commissioner Nirav Shah said that he was "in no hurry" to finish the review as he did not want to "play with any potential risks with the health and safety of New Yorkers." Cuomo has said that he did not want to put "undue pressure" on Shah. "My timeline is whatever commissioner Shah needs to do it right and feel comfortable," said Cuomo.

Shah has since resigned and the charge has been handed over to an acting commissioner, which will probably only further delay a decision.

I vaguely remember reading something about a recent court ruling in New York. It made a lot of the anti-fracking activists very happy. What was it about?

Two small towns in upstate New York, Dryden and Middlefield, had banned fracking within their boundaries. Soon after, an energy company in Dryden and a dairy farm that had leased land for drilling in Middlefield sued the municipalities, arguing that the towns did not have the authority to limit drilling activity. The lower courts initially dismissed the lawsuits. On appeal, intermediate level courts upheld the ruling and most recently the state Court of Appeals also upheld the decision.

"The towns both studied the issue and acted within their home rule powers in determining that gas drilling would permanently alter and adversely affect the deliberately-cultivated, small-town character of their communities," wrote Judge Victoria Graffeo in the majority ruling.

And why is this court ruling so important?

It gives towns the authority to decide whether they're willing to allow fracking within their town boundaries. Several towns already have bans in place against fracking. This ruling ensures that if those towns were to be met with similar lawsuits, they'd still be able to enforce the ban. Also, if Cuomo lifted the state-wide moratorium, towns can individually take action through local ordinances.

Wait, doesn't fracking cause your water to light on fire? Should New Yorkers worry about their water supply?

ProPublica's reporting over the years has shown that fracking can be done safely, and very often is. That said, natural gas drilling and fracking done improperly or recklessly can be a threat to water safety. - Residents of New York City, though, probably don't have much to worry about. New York City and several upstate communities receive water from the Delaware, Catskill and Croton watersheds, where there is currently no fracking taking place because of the moratorium. If the health review process came to an end and Cuomo made a decision on fracking, there are several scenarios that could play out.

- Fracking could be banned altogether in the state
- Fracking could be allowed in the state and additional regulations specifically banning fracking on land overlying the New York City watersheds and their buffer areas could be passed
- Fracking could be allowed almost anywhere in the state, including over the New York City watersheds

Though considered highly unlikely, if the third scenario were to play out, environmental groups will almost definitely sue the state and try to block drilling over the watersheds. The watersheds are a statewide resource, providing unfiltered drinking water to over 9 million people, and New York City alone has spent hundreds of millions of dollars acquiring land and protecting it. About 37 percent of the land overlying two of the watersheds is protected through land trusts and direct ownership, and the City has an agreement with the state and watershed towns, which gives it some negotiation power with the state.

Finally, the recent court ruling also means that the towns which contain the watersheds could also band together and ban fracking. While it is highly unlikely that it will come to that, the option is now available to towns if needed.

Is there a video I can watch that explains the issues with fracking?

Why, yes. Here is the link: http://www.youtube.com/watch?v=oHQu3SeUwUI

A NEW WAY OF FRACKING

With HYDRAULIC FRACTURING an established practice, oil and gas firms turn to reducing the technology's environmental footprint

STEPHEN K. RITTER, C&EN WASHINGTON

HYDRAULIC FRACTURING, or fracking, has been a bonanza for oil and natural gas companies. So far fracking has yielded more than 7 billion barrels of oil and 600 trillion cu ft of natural gas in the U.S. alone, according to the American Petroleum Institute. Natural gas in U.S. shale deposits in particular is expected to remain abundant for more than 100 years, and by 2040 fracking is projected to account for half of U.S. natural gas production, compared with about 35% today.

Yet a lot of effort is still needed to get the oil and gas out of the ground. Fracking consumes vast amounts of freshwater, generates more waste than the raw materials it consumes, contributes to Earth's atmospheric greenhouse gas burden, and in some cases compromises drinking water sources near drilling sites. For many, fracking has become a four-letter word.

Among the unmet needs that could mitigate some of fracking's environmental downsides and turn that public perception around are safe and sustainable technologies that are more protective of water resources. To that end, scientists and engineers have been pioneering more efficient fracking fluid formulations and new types of tracers to help improve fracking performance and environmental monitoring of fracking chemicals.

"The fracking industry has gone through about eight years of what we might call brute-force fracking—just pump as much fluid as fast as you can, and that would get the gas production results you wanted," says James Hill, chief executive officer of GasFrac, an energy services company with headquarters in Calgary, Alberta, that is at the forefront of new fracking technology. "But now we are beginning to see a change and are moving toward being more scientific and optimizing how we are doing fracs."

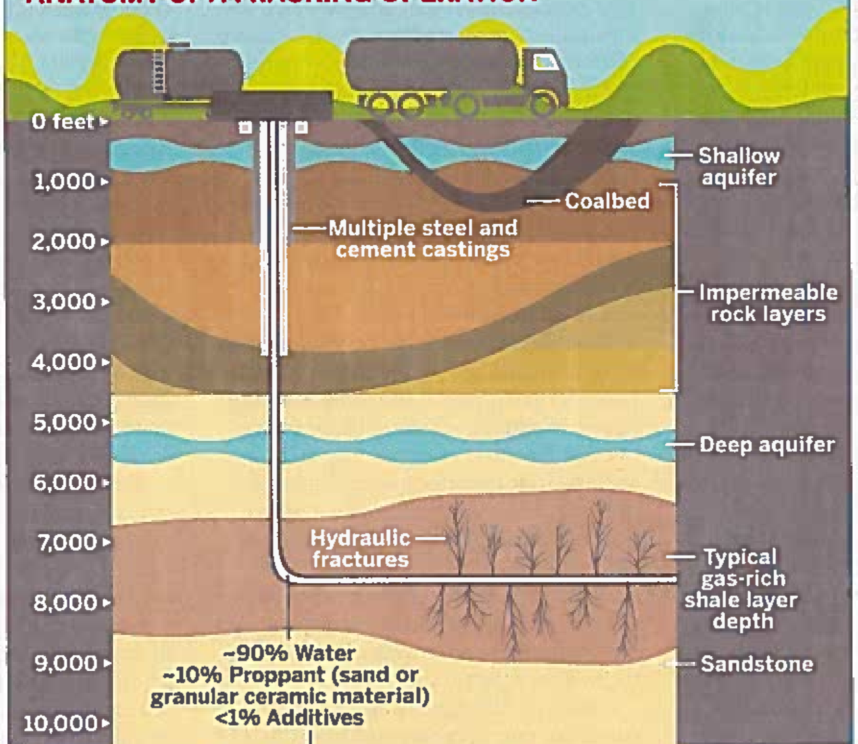
In the fracking process, a viscous fluid is pumped down a predrilled well hole into shale deposits where oil and gas are trapped. Shale is highly porous, but not permeable, so high pressure generated by the pumped fluid is used to fracture the rock, like cracking a car windshield. The fractures give access to little pockets of hydrocarbons that have been isolated for millions of years.

Fracking fluid is typically about 90% water, about 10% proppant (sand or a granular ceramic material), and less than 1% of an assortment of chemical additives customized for each well to optimize delivery of the proppant to the fracturing zone. Once a fracture is made and the pumping stops, some of the fluid flows back out of the well, and along with it a little extra mineral-laden water bearing toxic heavy metals and naturally occurring radioactive elements. The proppant remains behind, filling the hairline fractures to prop them open and allow the oil and natural gas to seep out, which may take place for 20 to 40 years.

The wells, which routinely stretch more than a mile deep and a mile laterally, are extended by about 200 yards or so between each round of fracking. Each well might be fracked 20 times or more, with each round taking on average several million gallons of water and 300,000 lb of proppant.

Fracking typically uses freshwater, and as a first step industry researchers have been working to perfect fluid-thickening and friction-reducing additives that allow operators to use less water. These chemical agents further provide flexibility in formulating fracking fluid

ANATOMY OF A FRACKING OPERATION



Common Water-Based Fracking Fluid Additives

Ingredient	Example	Function
Acid	Hydrochloric acid	Clears debris from well bore
Thickener	Guar gum	Increases viscosity of fluid to disperse proppant
Friction reducer	Polyacrylamide	Aids flow of fluid deep underground
Scale inhibitor	Ethylene glycol	Prevents carbonate/sulfate deposits
Corrosion inhibitor	Methanol	Protects steel casings
Biocide	Glutaraldehyde	Prevents microbial fouling

SHUTTERSTOCK/C&EN

so that recycled fracking water or brine pumped from saline aquifers underground, which contain undesirable dissolved solids, can now be used in place of freshwater.

But even better than reducing water use would be to exclude water from the fracking fluid altogether. That's where Hill and his team at GasFrac come in. Instead of water, GasFrac uses a gel made from propane, which is a component of natural gas.

Water is used for fracking mainly because it is incompressible—that is, its volume remains nearly the same even when under pressure. It's therefore very effective in building pressure against and ultimately breaking up rock.

THE PROPANE is in liquid form, Hill explains, so it works nearly as well. To create the fracking fluid, GasFrac adds less than 1% concentration of ferric sulfate as an activator to promote gelling and later a similar amount of magnesium oxide as a breaker to disrupt gelling. When ferric sulfate is added, the liquid gels in just a few seconds. As that is happening, the proppant is added.

"We are delivering proppant by viscosity, rather than by velocity, which is the case with a water-based system," Hill says. "The gel retains proppant better than water and evenly disperses it throughout the well, so it's possible to get the same results with about 10% as much fracking fluid and to pump it at a slower rate."

The surface tension of propane is about 10% that of water, Hill adds, enabling nearly all of the fracking fluid to completely flow back out of the well and be recovered. "Because propane is a hydrocarbon, it simply becomes part of the oil or gas production stream, whereas water tends to get stuck in the formation," he says. GasFrac's process is generally waste-free, but any natural groundwater that comes out of the well hole must be captured and treated.

As a bonus, the GasFrac process requires fewer chemical additives than water-based fracking. For example, without water the mix doesn't need a biocide, such as glutaraldehyde, $CH_2(CH_2CHO)_2$, to prevent growth of bacteria and mold that can clog the well. The biocide is typically the most environmentally problematic component of the fracking fluid additives.

To date, GasFrac's technology has been employed in some 2,600 fracking operations at 720 wells in the U.S. and Canada using more than 500 million gal of propane and 100 million lb of proppant. Even so, GasFrac's technology accounts for less than 1% of the North American fracturing market. "We are still a young technology," Hill says.

Beyond water use issues, the industry's biggest challenge is satisfying the public's right to know what fracking is doing to the environment. Residents in some areas where fracking is taking place have encountered methane in their water and worry about what else might be in it.

Because fractures remain separated from freshwater aquifers by several thousand feet of solid rock, fracking fluid should remain trapped deep below ground or should come back out of the well hole where it can be captured, reused, or disposed of as waste. In properly constructed wells made from concentric cement and steel pipe casings, industry experts like to say the chance of groundwater contamination is on the order of "one in a million fractures."

Hypothetically speaking, most of the pollution risk from fracking stems from how operators handle the fracking fluid and the waste flowback fluid aboveground, not directly from the underground fracking process itself. But not all wells are built properly, nor may they all hold up over time. And accidents happen.

Improved tracers to monitor wayward fracking fluid could provide a level of transparency to allay public concerns. Fracking operators often track short-lived radioactive isotope tracers such as ^{110}Ag or ^{131}I with a scintillation detector lowered into the well hole. They sometimes use chemical tracers such as fluorinated benzoic acids with mass spectrometry detection. The radioactive or chemical tracers are selected to measure proppant progress into the fracture zone and to determine which parts of the well are most productive.

However, the tracers don't last long enough or they become too dilute to assess whether a well is leaking or if fracking operations are tainting groundwater or surface

"Today's oil and gas is trapped in rock that is less permeable than concrete, which is why we need fracking."

water. Current environmental monitoring therefore tends to rely on sampling well water, streams, lakes, and wastewater ponds for contaminants.

Recognizing a need for fundamentally new types of tracers, two companies are moving forward with different approaches to frack watching. In one approach, a start-up company called FracEnsure, cofounded by Rice University materials scientist Andrew R. Barron, is developing superparamagnetic metal oxide nanoparticle tracers.

Barron's group has been developing ceramic fracking proppants, such as strong hollow spheres of aluminum oxide, for more than a decade. These materials are now commercially available from Oxane Materials, another firm Barron cofounded. "With subsequent research projects, we started learning about the mobility of nanoparticles in aqueous systems, which led us to expand our work to tracers," Barron says.

The Rice researchers make the nanoparticles by thermally decomposing metal acetylacetonate or metal oleate complexes. The nanoparticle surfaces are modified with a proprietary short-chain organic zwitterionic species that acts like a surfactant to help the particles disperse uniformly in fracking fluid.

The particle cores, which have different ratios of iron, manganese, and zinc, or of iron, gadolinium, and aluminum, are designed to exhibit a specific magnetic profile as a result of the unpaired electrons of the metal atoms. The distinctive magnetic signatures of each type of particle can serve to identify a batch of fracking fluid. A few dozen pounds of nanoparticles are needed for each fracking operation, Barron notes.

To monitor fracking fluid, the team uses a ceramic membrane filter developed by Barron's group for cleaning frack water to concentrate the particles and then isolates them using a magnet. The tracers' temperature-dependent superparamagnetism allows them to be distinguished from each other and from natural magnetic particles that emerge from the well hole when a test

GASFRAC

DRY FRACKING GasFrac's water-free technology uses gelled propane as a fluid to deliver proppant down the well bore.

sample is heated in a low magnetic field.

"We are starting to get at how to subtly modify the particles to get more complex information out of a well," Barron says. As the next step, Texas-based Southwestern Energy has plans to begin testing the nanoparticles in fracking wells later this year. Barron thinks the nanoparticles could first see action monitoring the integrity of injection wells, where industrial wastewater—including fracking fluid—is pumped for permanent storage or used to force out residual oil from partially depleted oil fields.

Taking a different approach to frack tracking, a start-up called BaseTrace located in Research Triangle Park, N.C., is using artificial DNA technology. The company's cofounder and CEO, Justine Chow, got together with some of her fellow Duke University environmental sciences graduates to introduce the technology.

Each tracer is a strand of DNA, fewer than 200 base pairs long, Chow explains. Because the short DNA sequences can be arranged in millions of different ways, each tracer has a unique signature like a fingerprint or bar code that can be assigned to each individual well or for each separate fracking stage in a well.

The oligonucleotide configuration is designed to withstand the extreme underground conditions associated with fracking, Chow says, including high temperature, high salinity, and shear forces. The DNA can also survive for up to two months when exposed to ultraviolet sunlight levels typical in impoundment ponds where companies store used fracking water for treatment or recycling.

Just a thimbleful of one of the tracers is all that needs to be added to millions of gallons of fracking fluid, Chow notes. Detection is performed by collecting samples, amplifying the DNA present using the polymerase chain reaction, and then determining whether the DNA tracer is present.

"We can detect the DNA in flowback fluid, making it possible to measure the efficiency of different fracturing stages and to trace whether or not that fluid ends up in places it's not supposed to be," Chow says.

Like FracEnsure, BaseTrace is still at the product development stage but gearing up to begin field trials. Chow envisions that one day her DNA tracers will be standard ingredients in fracking fluids. But for now she believes they might first be used to keep tabs on radioactive waste storage tanks.

"In the old days, having a classic oil well meant you dug a hole in the ground and stood back as oil gushed all over you, and then you moved to Beverly Hills," Rice's Barron muses. "But today's oil and gas is trapped in rock that is less permeable than concrete, which is why we need fracking. The fracking advances we are seeing now are tackling different problems. But all of them are aimed at making oil and gas extraction processes more efficient and reducing their environmental footprint." ■