

Environmental Considerations of Shale Gas Development

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The impacts of shale gas development on land, air, and water resources can and must be managed through sustainable operating practices.

As shale gas development has moved into more highly populated areas, concerns have been raised about the environmental footprint of these activities. The film *Gasland,* with its images of flaming tap water, has painted a one-sided, negative picture of shale gas development for viewers in the U.S., Europe, and other parts of the world, one in which shale gas developers are unregulated and routinely disregard sustainable operating practices. In addition, numerous reports, such as one that portrayed shale gas extraction as a greater threat to greenhouse gas (GHG) levels than coal mining *(1),* have cast a harsh spotlight on the gas industry's activities.

There is a growing perception that drilling operations pollute the air and consume too much land and water, and that hydraulic fracturing is a significant threat to the world's drinking water. Developers of shale gas have maintained, however, that horizontal drilling and hydraulic fracturing, the technologies used to stimulate and extract these resources, have been used and perfected for decades and have been proven to be safe.

It is true that improper handling and treatment of wastewater at the surface have caused some accidents, and errors related to well casing integrity may have contributed to methane and/or fracture fluid migration into a small number of shallow aquifers. However, it is also true that responsible participants are following region-specific best practices and are working with regulators to carefully monitor environmental conditions before, during, and after well construction and completion *(2).*

This article provides a summary of the potential environmental impacts posed to land, air, and water by shale gas development. Understanding the potential impacts and separating real from perceived risks are important, because unconventional gas constitutes an increasingly vital part of the world's energy supply picture.

Land footprint

One concern related to shale gas development is the amount of land that is required and that is disturbed throughout the process. Shale gas well construction and completion is an industrial and highly visible process. A typical drilling pad sits on a 2–6-acre plot of land and has a holding pond for water effluents, and it relies on hundreds of trucks to haul equipment and water to and from the site for the hydraulic fracturing operations that are conducted there.

Because shale gas typically exists in sedimentary rock deposits that stretch for long distances (for example, the Marcellus Shale occupies 54,000–96,000 mi^2) rather than in discreet pockets, the number of wells required to access the resource is large. These operations are sometimes referred to as gas farming. In regions where population densities are high, such in the northeastern U.S., local concerns about development activities encroaching on areas where people live, work, and play are understandable. In contrast, most oil and gas development over the last 50 years has taken place in less-populated areas in the western U.S. or in areas where residents are more familiar with energy-development activities.

Reducing the surface impact of shale gas development is not only environmentally beneficial but is also in the economic interest of operators, and is a significant focus of technology development. For instance, drilling multiple wells from a single pad allows operators to reach a larger underground area of the resource from the same, much smaller surface area.

The progress that has been made to date is dramatic. In 1970, approximately 502 acres of subsurface area could be drilled from a 20-acre well pad at the surface, whereas today's technology provides access to more than 32,000 acres of subsurface area from a 6-acre well pad at the surface. In addition, natural gas has the second-lowest surface-disturbance impact per unit of electricity generation of all energy sources, behind only nuclear power production *(3)*. As new technologies and best practices move into new production areas, even more footprint reductions will be achievable.

At some point after a well begins to produce natural gas, the drilling company is obligated to restore the site to approximately the condition of its original landscaping and/or previous land use. Generally, a wellhead, two or three brine storage tanks, a metering system, and some production equipment remain on the site.

When a well is no longer capable of production, concrete is pumped down the wellbore to seal it from atmospheric pressure, and production equipment is removed from the site. The entire pad is then revegetated and fully restored.

Induced seismicity

Concerns about the role of hydraulic fracturing and deep-well injection disposal in triggering localized earthquakes (such as were experienced in Texas in 2009, Arkansas in 2011, and Ohio in 2012) have arisen in recent years. Studies conducted to date do not indicate a direct correlation between these earthquakes and drilling or well-completion activities. The primary connection appears to be the improper disposal of wastewater produced from shale gas wells *(4)*.

Seismic activity (seismicity) is generated in two ways. One is through hydraulic fracturing using water, sand, and chemical additives to release natural gas trapped within shale deposits. In fact, the specific intent of hydraulic fracturing is to create permeability in the rock by inducing microseismicity. The second way of generating seismicity is through the subsurface disposal of wastewater and naturally occurring brines that emerge with the desired hydrocarbons after a well is fractured. This type of seismicity is common in many oil and gas fields. All measured seismic activities in the history of shale gas exploration have been small, generally between 2.0 and 4.0 on the Richter Scale, and have not posed a danger to either humans or the environment *(5)*.

In hydraulic fracturing, the magnitude of a seismic event is proportional to the length of the fracture, which is largely a function of the amount of water injected and the injection rate. Provided that care is taken to not pressurize the system too much or too quickly, rupture lengths and seismic magnitudes should be negligible. Current evidence suggests that the risks associated with hydrofracture-induced seismicity are very low. With appropriate management, induced seismicity is not likely to be an impediment to further development of shale gas activities *(5)*.

However, the disposal of waste fluids in Class II deep injection wells is considered a potential cause of minor earthquakes that have been felt at the surface *(4)*. Class II injection wells are used to dispose of fluids associated with the production of oil and natural gas, to inject fluids for enhanced oil recovery, and for the storage of liquid hydrocarbons. As a condition of permitting Class II injection wells in the U.S., disposal wells are located in areas far from identified fault lines, and injection rates are limited to prevent substantial increases in pore pressure at the well depth. Seismic monitoring networks can be installed to detect seismic activity so that actions may be taken to decrease or stop injection if necessary.

The possible causal relationship between deep-well injection and minor earthquakes is not yet fully understood and requires additional investigation.

Air emissions

Natural gas is often lauded for its air quality benefits, as it is the cleanest fossil fuel (primarily because its combustion produces low levels of carbon dioxide emissions). For example, generating electricity with natural gas creates about half the CO_2 emissions of coal-based power generation and 30% less than fuel-oil-based generation. Furthermore, its combustion byproducts are mostly carbon dioxide and water vapor. Consequently, natural gas is considered to be the main fuel in energy industry plans to reduce carbon emissions.

However, shale gas production is not without any air footprint. Exploration in the Marcellus Shale has been shown to impact local air quality and to release some greenhouse gases into the atmosphere *(6)*.

The sources of air emissions depend on the phase of the development process. In the preproduction (drilling and completion) phase, emissions may come from drilling rigs and fracturing engines, which are typically fueled by diesel or gasoline. Air emissions are also created by the many trucks delivering water to the site and hauling wastewater from it. The number of truckloads required varies from site to site, and depends on the amount of water needed, the amount of wastewater generated, the location of the water source, and the distance from the well to the wastewater treatment or disposal facility. In the Marcellus Shale region, for instance, 4 million gal of water are typically required to fracture-treat a single horizontal well, which equates to 800 U.S. truckloads.

After drilling and fracturing operations are finished, the production of natural gas begins. During this phase of operation, compressor engines (and any venting or flaring of gas before gathering lines are in place) can



produce emissions. Fluids (condensate) brought to the surface may include a mixture of natural gas, other gases, water, and hydrocarbon liquids, which can be released into the atmosphere from the condensate tanks *(6)*.

Table 1 lists the main emissions that may be created during drilling, hydrofracturing, and gas extraction.

Air emissions have been measured and analyzed during the extraction of Barnett Shale gas in Texas and in other shale operations in the western U.S. *(6)*. Based on this and other studies, some states have changed their air quality regulations to reduce hydrocarbon emissions during shale gas production.

On April 18, 2012, the U.S. Environmental Protection Agency (EPA) released new air quality rules for hydraulically fractured wells. Beginning in 2015, the regulation requires drillers to use technologies and practices that limit emissions and result in so-called green completions. After a well has been fracture-treated, it is cleaned up, which involves removing the water that was used for fracturing. During this flowback, some natural gas accompanies the water exiting the well. In green well completions, this gas is separated from the water and placed in a pipeline instead of being released to the atmosphere or flared.

Devon Energy's green completion process *(7)*, for example, employs a sand separator to filter out sand, which is sent through a 2-in. pipe into a disposal tank, leaving behind a mixture of natural gas and water. A second separator removes the water from the gas, and the water is recombined with the sand in the disposal tank. The natural gas, meanwhile, is diverted into a separate pipe, and is eventually sent by pipeline to a gas-processing plant.

Because methane is the largest component of natural gas — and methane emissions represent lost product that energy companies would rather produce and sell — most of today's wellheads and pipelines exceed the new EPA benchmark. Many operators have found that the additional revenue that can be generated through green completion offsets a portion of the additional costs associated with extra processing.

Water footprint

Water footprint is perhaps the most contentious environmental issue associated with unconventional gas development. Areas of concern include the management of water for all users in the watershed; the fear of contamination of surface water and/or groundwater during site preparation, drilling, and well completion; and the treatment and safe disposal of the produced water (*i.e.,* water that occurs naturally in the formation and flows to the surface with the gas).

Growth in the development and production of shale gas resources will require greater sourcing of water and management of water, solid waste, and other byproducts. Current practice involves drilling multiple wells from one or two pads in a well field, and constructing hundreds of well fields within each development area. An analysis by the Gas Technology Institute *(8)* found that the quantity and quality of the water that flows back from completed wells over a 45-yr lifecycle of a development area — as well as the output of solid waste, including drilling waste — are highly dynamic and vary from year to year. For example, although water flow from a single well may decrease over time, the salt concentration of that water may increase.

During the construction of well fields, water must be found (sourced), hundreds of thousands of truckloads must transport water to wellheads for hydraulic fracturing of the shale to initiate gas production, tens of millions of barrels of brine (collected as flowback water and produced water) must

Table 1. Air emissions from drilling, hydraulic fracturing, and shale gas extraction activities may contain these compounds.

Compound	Description	Environmental Concern
Methane (CH_4)	The main component of natural gas	A known greenhouse gas
Nitrogen Oxides (NOx)	Formed when fossil fuel is burned to power machinery, compressor engines, and trucks, and during flaring	A precursor to ozone formation
Volatile Organic Compounds (VOCs)	Hydrocarbons, including aromatics (*e.g.,* BTEX) and light alkanes and alkenes. Present in flowback water. May be released during handling and storage in open impoundments	Partial transport of VOCs occurs from water to air
Benzene, Toluene, Ethyl Benzene, and Xylenes (BTEX)	Compounds emitted in low quantities	Toxic to living organisms above certain concentrations
Carbon Monoxide	Occurs during flaring and as a result of incomplete combustion of carbon-based fuels used in engines	Toxic to living organisms above certain concentrations
Sulfur Dioxide (SO_2)	May form when fossil fuels containing small amounts of sulfur are burned	Contributes to acid rain
Hydrogen Sulfide (H_2S)	Exists naturally in some oil and gas formations. May be released when gas leaks, is vented, or burns incompletely during flaring	During natural gas production, operations, and utilization, hydrogen sulfide releases to the atmosphere are very low

be reused or disposed of in an environmentally acceptable manner, and hundreds of thousands of tons of drilling waste and sludge must be carefully managed. Since water and waste management account for a large portion of the annual operating costs of shale gas development, the economical and environmentally acceptable management of these streams is critical to the sustainable development of shale gas plays.

When procuring water for hydraulic fracturing, it is essential to protect water quality and to ensure adequate water resources for other watershed stakeholders, including residential, commercial, and industrial users that depend on water. Water for drilling and fracturing of shale gas wells frequently comes from surface water bodies such as rivers and lakes. It can also come from groundwater, private water sources, and municipal water supplies, and recycled fracturing water can be used as well. While the water volumes needed for drilling and stimulating shale gas wells are significant, they generally represent a small portion — typically less than 1% — of the total water resource in a shale gas basin *(6)*.

Many shale gas basins are located in regions that receive moderate to high levels of precipitation. Even in areas of high precipitation, though, the needs of growing populations, other industrial water demands, and seasonal variation in precipitation can make it difficult to meet the water demands of shale gas extraction.

It is also important to consider the connection between water quantity and water quality. For example, taking water for drilling and fracturing from a small stream, rather than from a large river or lake, places a relatively larger burden on plants and wildlife within the immediate ecosystem. Similarly, if fracturing fluid were released into a small stream (regulations and industry recommended practices prohibit this practice), the chemicals might not be diluted sufficiently to prevent damage to fragile ecosystems and aquatic life.

Local water quality may be compromised at several stages of shale gas extraction. Gaining access to the well site involves building access roads for heavy equipment to transport drilling rigs, pipe, and water. Transporting material to the site and site preparation can cause erosion. Drilling through aquifers can contaminate water supplies if proper precautions are not taken to isolate the aquifer from the wellbore.

One of the most important developments in recent years to reduce water footprint is the practice of reusing the flowback water (the fracture fluids that return to the surface after completion of a well) from one well to supplement a portion of the water volume required for the next well's hydraulic fracture treatment. Typically, most of the fracture water that flows back does so during the first few weeks after hydraulic fracturing ends. Reusing this water reduces the potential for environmental impact by reducing air emissions and carbon footprint, water transportation requirements, truck traffic densities, and road wear, and generally results in greater stakeholder acceptance. Even this reuse, however, is transportation-intensive — moving 1 million gal of flowback water from one well to the next requires more than 200 truckloads. Furthermore, the reused water is only about 20–25% of the total 4–5 million gal of water typically needed to fracture the next well.

In addition to reuse, operators may dispose of flowback and produced water by deep-well injection at permitted wells. However, this option is available only in regions where the geology is suitable for deep injection and where such disposal wells have been drilled.

Another option for flowback disposal is the reintroduction of water from hydraulic fracturing to surface water or groundwater. Although this can be an environmentally safe practice if the water is sufficiently treated to remove contaminants, it can be very expensive. Constituents that may need to be removed include fracture fluid additives (*e.g.,* friction reducers), oils and greases, metals, and salts. Salt separation in particular is very energy-intensive and thus expensive. While the industry is working to reduce the cost of such treatment, it will be important for operators to continue treating water for reuse and to protect equipment and the shale formation from damage.

This portfolio of water management options gives operators flexibility and helps to minimize freshwater requirements for shale gas development.

Groundwater contamination

The most hotly contested water footprint issue associated with shale gas development is the potential for drinking water contamination by hydraulic fracturing.

To avoid contamination, multiple layers of steel casing are inserted into the wellbore. The casing reinforces the wellbore and prevents it from collapsing, and isolates it from the surrounding rock formations.

The producible portions of deep shale gas formations exist many thousands of feet below the earth's surface. For example, the productive area of the Marcellus Shale is located at depths ranging from 4,000 ft to 8,500 ft underground, and the typical well there is more than 5,000 ft deep. In contrast, groundwater aquifers in that area are found at depths less than 1,000 ft. Throughout the Marcellus Shale, groundwater aquifers and producing natural gas formations are separated by thousands of feet of protective rock barriers.

The fractures created by hydraulic fracturing propagate upward a few hundred feet at most — significantly short of what would be required to reach the fresh-water aquifers. Fracturing fluid migration from deep shale gas wells into fresh-water aquifers has not been observed *(9)*. The fracture fluid remains deep in the earth, and the same low permeability that causes the need for hydraulic fracturing is believed to prevent fluid migration.



However, recent research has raised additional questions about the possibility of methane, a key component of natural gas, flowing from deep underground in the Marcellus through natural pathways in rock to aquifers near the surface *(10)*. To assess the potential impacts of fracturing on groundwater quality, it is useful to consider some of the assertions that have been made about methane migration from hydraulically induced fractures into groundwater.

In one case, a homeowner who suspected that a gas well near Dallas, TX, was affecting the quality of his water well, which draws from the Trinity aquifer, brought a claim against Range Resources in 2010. EPA testing *(11)* confirmed that there were traces of methane in the homeowner's well water. The methane was thermogenic gas (created by high heat and pressure converting organic material to natural gas), which suggested to the EPA that it had originated from a deep source — such as that developed by Range Resources — rather than shallower sources of naturally occurring biogenic gas (which is created from organic material by organisms such as bacteria). The EPA issued a remediation order and an endangerment finding against Range Resources and voiced its concern about natural gas building up in homes and creating the potential for fire or explosion.

The EPA's allegation received a good deal of media attention. However, if that were true, the methane would have had to migrate through 5,000 ft of solid rock or the well's casing would have had to have lost its integrity. Pressure testing found no mechanisms to enable the gas to migrate up from such a deep source and confirmed the integrity of the well. In addition, the reported methane concentrations in the samples were below safety limits for well water. Later testing confirmed that, based on the nitrogen content of the gas, the source of the methane is actually a rock strata laden with natural gas and salt water called the Strawn formation, which sits just below the Trinity aquifer at a depth of 400 ft — not the Barnett shale, which is 5,000 ft deeper *(12)*.

The homeowner's representatives continue to argue that the source could be the Range Resources well, because it is drilled through the Strawn formation and the production casing is not cemented in that section. Recent reports indicate, though, that several water wells in the area contained trace quantities of methane before any gas wells were drilled in the area *(13)*. The case was recently dropped by the EPA, although it was not clear whether the Agency's technical staff had reversed its views on the cause of methane contamination. Nevertheless, it appears likely that fracture propagation was not the cause.

In another case, a Duke Univ. study *(14)* found that surface water near Marcellus Shale drilling sites has higher methane concentrations than nearby surface waters that are not near drilling sites, and that the methane is thermogenic in nature. The Duke samples did not show any evidence of fracturing fluid migration to groundwater, but they did highlight concerns about possible methane migration. Baseline measurements were not taken prior to drilling and isotopic data presented were not compared with the multiple gas formations that exist in the region.

A recent paper *(15)* found that the isotopic signature of the Duke study's thermogenic methane samples are more consistent with those of shallower Upper and Middle Devonian deposits that overlay the Marcellus Shale. These data suggest that the methane samples analyzed in the Duke study could have originated entirely from those shallower sources above the Marcellus and are not related to hydraulic fracturing activities.

This is consistent with a 2010 assessment by the EPA *(16)* in response to well-publicized reports of elevated methane in water in the town of Dimock, PA, the site of the dramatic *Gasland* footage in which a homeowner lit his kitchen tap water on fire. In addition, technical literature and historical publications confirm that methane gas was present in water wells in the region for many decades, and long before shale gas drilling began in 2006 in the area.

The most recent coverage of possible groundwater contamination by fracturing activities resulted from sampling near the town of Pavillion, WY. In December 2011, the EPA issued a draft report *(17)* of a study conducted in response to complaints of objectionable taste and odor problems in well water. The EPA suggests this is the first major study detecting a link between fracturing and groundwater pollution, although the study has not yet been peer reviewed. Analysis of samples taken from deep monitoring wells in the aquifer detected synthetic chemicals consistent with gas production and hydraulic fracturing fluids (glycols and alcohols), benzene concentrations well above Safe Drinking Water Act standards, and high methane levels.

The EPA notes that the draft findings are specific to Pavillion, where the fracturing is taking place in and below the drinking water aquifer — in contrast to fracturing taking place 1–3 km below aquifers in most other locations — and in close proximity to drinking water wells. These production conditions are unlike those in many other areas. Furthermore, other factors may be affecting the Pavillion samples.

One dangerous compound highlighted by EPA was 2-butoxyethyl phosphate. The Petroleum Association of Wyoming has pointed out that this is not an oil and gas chemical, but, rather, is a common fire retardant used in plastics and plastic components in drinking water wells. The testing also detected benzene, which is highly unlikely to have been sourced from the shale gas formation. In addition, the EPA found glycol, which is not injected downhole in this region but is used at the surface. Finally, the contamination detected was in samples from deep monitoring wells, and not the shallower drinking water wells.

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Another explanation for the foul water may be that bacteria have entered the water supply as a result of improper maintenance of aging water wells. More testing will be required to clarify the source of the contamination in this region.

Although it has not been demonstrated that fractures can reach fresh groundwater, the potential exists for contamination due to spills at the surface and to leaks from improperly cemented well casing. Thus, the use of sustainable operating practices that include responsible management of hydraulic fracturing fluids is important.

Fracturing fluid is typically 90.6% water, 9% proppant (often sand) used to keep the fractures open, and 0.4% chemicals added for such purposes as reducing friction and protecting equipment from corrosion. (Many states require public disclosure of the chemical ingredients, but their proportions are considered proprietary information.) These chemicals are used for a wide variety of other applications, including household detergents, food additives, and swimming pool treatments. While the risk of contamination or toxicity should not be ignored, it is important to keep in mind that these are chemicals commonly encountered in daily life.

A movement is currently underway toward the use of greener fluids. This involves reducing or minimizing the amount of chemical additives in the fluids, or finding more environmentally friendly and/or biodegradable options for those chemicals that are essential (*e.g.,* biocides, friction reducers, scale inhibitors),

Another key issue is the salt content of the produced and flowback water, which contains total dissolved solids in a mixture of carbonates, chlorides, sulfates, nitrates, sodium, and other minerals. In some shale formations (*e.g.,* the Marcellus), the solids content of the produced and flowback waters (mostly salts) rises dramatically in the first several days after a fracture application. Flowrates usually fall dramatically over time, so the total amount of salts brought to the surface is limited. Nevertheless, as thousands of wells are completed in an area, the aggregate flows of water with high salt content could prove to be a costly challenge if these waters are to be reintroduced into the natural ecosystem. If handled responsibly, the chance of environmental contamination should be minimized *(8).*

There have been some documented cases of localized releases of fluids at the surface caused by spills and casing ruptures *(18).* (Regulators fined the operators of those wells, and the operators cleaned up the spills and provided alternative sources of fresh water until monitoring could provide the assurance that water quality was restored.) Methane is not an issue with regard to water quality if such a release occurs. Rather, the most significant risk to the environment is the potentially high salt concentrations.

In 60 years of hydraulic fracturing activity, there is yet to be a single proven case of groundwater contamination that has been tied to the practice. This is not to discount the real concerns people have or the potential immediate or long-term environmental impact risks, which should and will continue to be studied. However, it is also important to put any perceived or real risk from hydraulic fracturing in context with other everyday risks *(19).*

Adding such context to what is a spirited conversation about hydraulic fracturing will help society to make more informed decisions and trade-offs between energy sources and the technologies utilized to produce them.

Closing thoughts

Like the development of any energy resource, shale gas development has impacts on land, air, and water resources that can and must be managed. Experience in North America and Europe has shown that failure to adopt sustainable operating practices at the beginning of development activities has led to some operational problems, and lack of adequate explanation of the technology to the public have resulted in media coverage that was not always fact-based. Fortunately, both of these are changing.

Sustainable energy development is increasingly understood as the creation of not only long-term economic value from energy production and utilization, but also long-term environmental and social value for a wide range of stakeholders, including shareholders, employees, consumers, suppliers, communities, and public sector partners. Abundant natural gas will strengthen our economy, energy security, and independence if and only if its production operations are sustainable and completely transparent, and development activities are sensitive of nearby public areas, habitats, and protected resources. CEP

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