HYDRAULIC FRACTURING AND SHALE GAS EXTRACTION

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Abstract

In the past decade the technique of horizontal drilling and hydraulic fracturing has been improved so much that it has become a cost effective method to extract natural gas from shale formations deep below the earth’s surface. Natural gas extraction has boomed in the past few years in the United States, enough that it has driven prices to an all time low. The amount of natural gas reserves in the U.S. has led to claims that it can lead the country to energy independence. It has also been touted as a cleaner fuel for electricity generation and to power vehicles.

This report explains hydraulic fracturing and horizontal drilling particularly with regards to utilizing the techniques for natural gas extraction from shale gas. It also discusses the environmental impact due to the drilling and gas extraction. It demonstrates that although the natural gas beneath the U.S. is a valuable resource, the impacts to the planet and mankind are not to be taken lightly. There is the potential for the effects to be long term and detrimental if measures are not taken now to control them. In addition although on the surface natural gas seems to be a greener fuel, particularly in comparison to gasoline, it is also considered worse for the environment.

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Chapter 1 - Hydraulic Fracturing

Fracturing is a method that expands or creates pathways in the subsurface and allows materials to more easily flow through the earth. There are many different methods to fracture the subsurface but in the past decade the use of water with chemical additives has been used extensively. This method is known as hydraulic fracturing or "fracking" and the fluid is simply known as fracturing fluid. In addition, the fracturing fluid contains a proppant, which is typically sand, in order to hold the newly created fractures open. Hydraulic fracturing is particularly effective in shale, a sedimentary rock that is created by the compaction of silt and clay. It is made up of many thin layers and is easily split into thin slices along the layers. In addition to the silt and clay compressing, organic materials are also compressed and transform into oil and natural gas. Methane comprises 70-90% of natural gas with the balance being other hydrocarbons, carbon dioxide, oxygen, nitrogen, and hydrogen sulfide.[1] Horizontal drilling allows lateral drilling which gains companies more access to the natural gas they are recovering than is possible with vertical drilling.

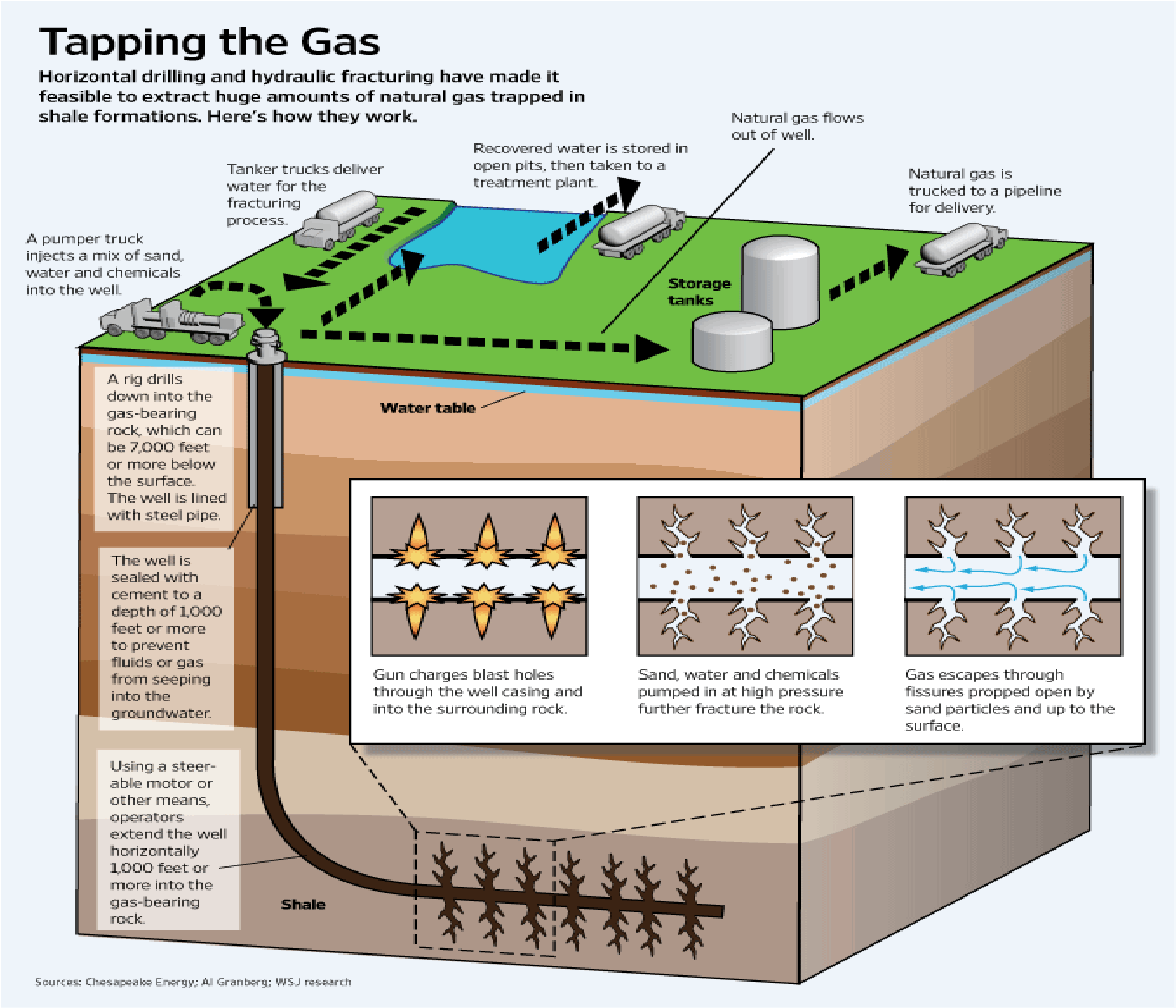
Wells have been drilled for petroleum exploration in the United States since the mid 19th century.[2] Fracturing began to be used in the 1860s to extract more oil from wells that were drilled into hard rock.[3] If the subsurface pathways that allowed gas and oil to flow are opened up, then the gas and oil flows more freely. Initially, explosive fluids such as nitroglycerine were used in order to break up the subsurface soils to create these pathways. In the 1930s and 1940s research and experimentation into the use of non-explosive fluids began. The early experimenters believed if they injected an acid into the rock along with pressure it would not only open up pathways but also etch the rock so that the pathways would stay open. One oil company, Amoco, acted on these ideas and experimented by injecting napalm into two wells in Kansas. Although the fracturing was not a success in terms of increasing yields from the wells, it opened the doors on the technology. Amoco then patented the technique and licensed it to Halliburton, which began to use fracturing on a commercial basis and improved on the processes.[3] In the 1980/90s fracturing started to be combined with horizontal drilling into natural gas fields in Texas. The horizontal drilling allowed a company to drill a well into a single point but gain access to much more gas than in the localized drill area by extending the well thousands of feet through the shale formation.

Horizontal drilling and hydraulic fracturing are elaborate processes which are an impressive feat of engineering and technology. A typical drill sites utilize approximately 2-4 acres of land. Land is selected based on the potential for extraction in that area and also the willingness of a landowner to lease their land to the gas company. The land is used for drilling as well as equipment and water storage. Figure 1.1 shows the layout and footprint of a typical drill pad. As seen in the photo, a large amount of trucks and trailers are necessary at the site. There are trucks that mix, blend, and pump the fluid. Trailers provide the engineers' offices and sleeping quarters and offices for the superintendant and rig hands. The large tower in Figure 1.1 is the mast with the crown block, the assembly where the pulleys are located for the drilling line, at the top. The drilling line is attached to a traveling block that allows equipment to be raised and lowered in the mast. Between the mast and the large pool is the equipment that separates the mud cuttings generated from drilling from the drilling fluid. Finally, the large pool in Figure 1.1 is the storage pond for the drill cuttings generated and later spent drilling fluids. Other trailers and storage tanks contain generators for electricity, diesel fuel to power equipment, and water storage if it is not pumped in.[4] A typical well will use up to 5 million gallons of water throughout the drilling and fracturing process so between the equipment and water required a significant amount of space is needed.

Figure 1.1 Photograph of a typical fracturing and drill pad[5]

Wells are drilled into the earth below the lowest aquifer at the site. A steel well casing is installed along with cement to provide a barrier between the well and groundwater. Once past the aquifer the drilling continues vertically to the “kickoff point” where the lateral drilling begins. The well is then drilled another 3-5000 feet horizontally through the shale where the gas is trapped. During the drilling, process fluids are pumped into the well in order to bring the drill cuttings to the surface and to hold the well open. These cutting are stored on site and are typically buried at the end of the process.

Once the desired drill depth is reached, there are several more steps necessary to recover gas from the well. Additional well casing and concrete are installed. A perforating gun is installed into the well and detonated, creating holes in the casing and concrete to allow the fracturing fluid into the shale formation. After the fissures are created, fracturing zones are established with the use of mechanical plugs to isolate the horizontal distance being fractured at any given time. Next the fracturing fluid is pumped into the well at pressures up to 15,000 psi. This further aids in the creation of fissures to allow the gas to escape the well via the newly formed pressure gradient. The fluid also delivers proppant in the fissures to hold them open. The seals allow the fracturing to occur in stages with the seals being drilled out at each stage. At this point the gas is allowed to flow freely to the wellhead. Figure 1.2 illustrates the different stages of horizontal drilling combined with hydraulic fracturing.



Sources: Chesapeake Energy; Al Granberg; WSJ research

Figure 1.2 Stages of hydraulic fracturing[6]

The first fracturing fluids consisted mostly of crude and refined oils with sand as the proppant. Over the years many additives have been developed to increase the effectiveness of the fluid. For a list of the types of chemicals used in fracturing fluids see Appendix A.

The fracturing wells from the mid 20th century didn't utilize horizontal drilling and the first wells installed were at depths of around 2,400 feet, injecting about 750 gallons of water and 400 pounds of sand. Today, because of horizontal drilling, the average depth of a well is 7,700 feet and the amount of water used throughout the fracturing process is nearly 5 million gallons per well with over up to 100,000 pounds of sand. Utilization of resources and land has dramatically increased with the increased success of natural gas extraction.

Chapter 2 - Shale Gas

In the United States the production of natural gas from shale has increased from 1.3 trillion cubic feet in 2007 to 5.3 trillion cubic feet in 2012[7] due to the success of horizontal drilling and hydraulic fracturing. Natural gas production is measure in cubic feet of gas as measured at 60 °F and 14.7 psi.[8] There are several major shale gas plays in the U.S., areas where there are significant deposits of shale gas. The first to be exploited was the Barnett play in north-central Texas in the 1980s and 1990s. As the first gas companies became successful, more companies utilized the advanced technologies, until in 2005 the Barnett play was producing 500 billion cubic feet of natural gas per year, five times as much production as in the late 1990s. In 2012 production has surged to over 1.75 trillion cubic feet per year. As seen in Figure 2.1, much of the increase is due to horizontal drilling.

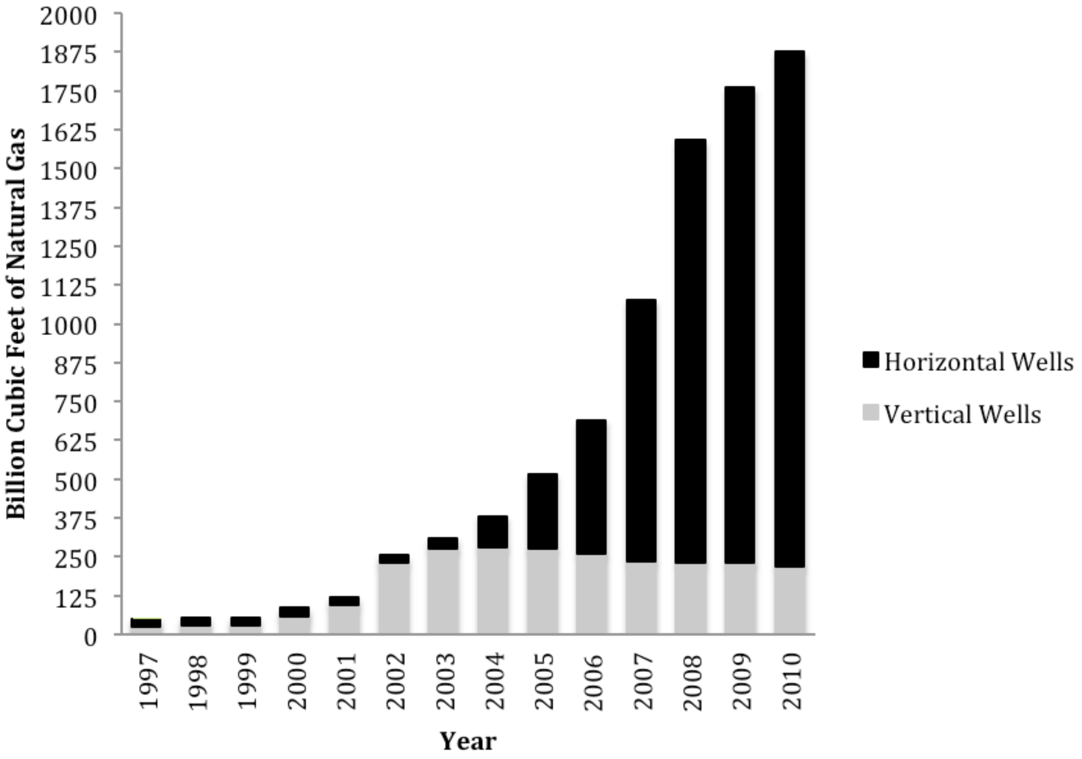
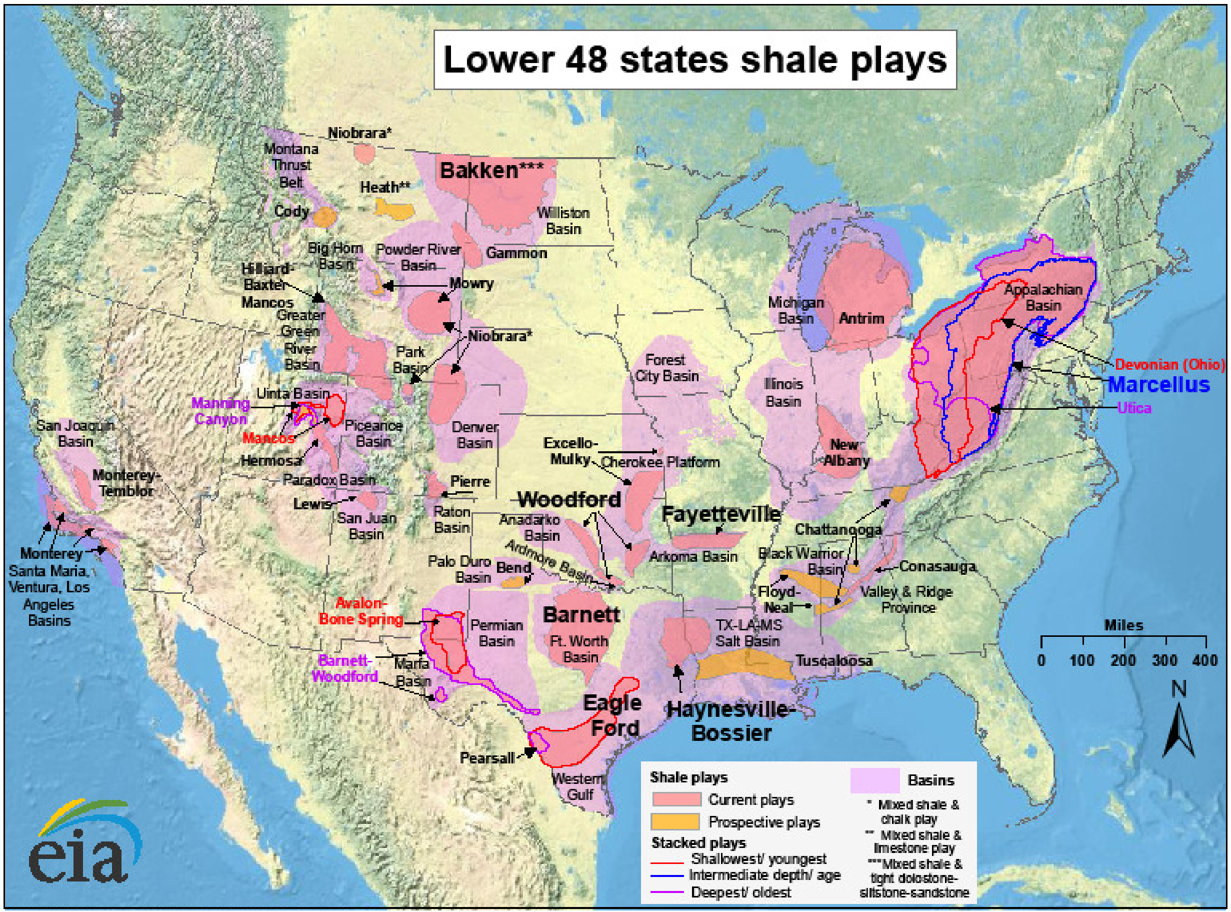


Figure 2.1 Annual Barnett shale natural gas production by well type[9]

As technologies improved and the number of drilling companies increased, more plays began to be explored and developed. Starting in 2007, plays such as the Fayettville in North Arkansas, Haynesville in Northwest Louisiana, and the Marcellus in the Appalachia of Northeastern United States all began major increases in production. Figure 2.2 shows the locations of the shale gas plays in the U.S. Hydraulic fracturing and shale gas extraction has spread to most of the U.S. Unlike Texas however, many of these regions are not used to the action and scenery of being home to drilling and gas operations.



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

Figure 2.2 Shale gas plays in the United States[10]

Today it is estimated that the United States has 862 trillion cubic feet of recoverable shale gas. Comparing this to an annual consumption of 22 trillion cubic feet in 2009, the amount of reserve gas is quite impressive. The U.S. is not the only country in the world with large shale gas reserves being estimated. China has the largest reserves with 1,275 trillion cubic feet and many European and South American countries also having large reserves.[11]

Chapter 3 - Environmental Concerns

Over the past few years the environmental impact of hydraulic fracturing and shale gas extraction has become a major concern. Because drilling activities have increased at such a rapid rate and encompass even more places, it has affected more and more people. In 2010 there was even a documentary film about the subject titled *Gasland*. It covered the health concerns and environmental impacts of hydraulic fracturing and gas extraction, specifically in Colorado.[12]

Water

The quantity of water utilized to fracture and extract the gas is considerable. Between drilling a well and the subsequent fracturing, the process utilizes approximately five million gallons of water.[13] To put this in perspective, an Olympic sized swimming pool holds approximately 660,000 gallons, so the water used in the extraction process is about 7.5 Olympic pools for one well. In addition, the water is mixed with several chemicals to create the fracturing fluid. The main components of the fracturing fluid are sand and water, comprising approximately 99.5% by volume of the fracturing fluid.[14] This amount of water can put considerable strain on local rivers, lakes, and aquifers if not carefully managed. Approximately 70-75% of the injected fracking fluid remains deep below the earth's surface. Because the water is removed from the earth's surface or accessible water tables, it is no longer in the natural water cycle and will never again be able to be used for anything else. Although this is a considerable amount of water, electricity generation in the Susquehanna River Basin, which is about the size of Pennsylvania, uses approximately 150 million gallons of water per day and 55 billion gallons of water per year.[15] The difference here is that the water utilized in electricity generation is mostly reused in a closed loop system or lost through evaporation. Either way, it stays in the usable water cycle. In addition, if the natural gas well is not situated near existing water or infrastructure for water, it may have to be trucked in. A large tanker truck holds about 9,000 gallons. If all the water has to be trucked in that could require up to 555 trucks trips. This doesn't even consider the return trip for the wastewater if required. The volume of trucks can cause localized air quality issues, nuisances in small towns and on rural roads, and also increased road maintenance and accidents.

Fracturing Fluid Chemicals

The fracturing fluids contain hundreds of chemicals added to increase the effectiveness of the fracture. Most of the chemicals have safety hazards including being carcinogenetic, causing skin, eye, and lung irritation. Appendix A lists many of the commonly used chemicals. Even though only 0.5% of the fracturing fluid is chemicals utilized to aid in the fracturing process, because of the large total volume required to fracture the well, this translates to roughly 25,000 gallons of chemicals. Given that in 2010, Pennsylvania issued more than 3,300 natural gas well permits and 1,500 of those were drilled[16], up to 37.5 million gallons of chemicals and 7.1 billion gallons of water have been used. Approximately 20 – 25% of these chemicals are not left in the subsurface and have to be stored on site, typically in open pits. A study on the chemicals used in fracturing by Colborn, et. al.[17] determined that "75% of the chemicals used could affect the skin, eyes and other sensory organs in addition to the respiratory and gastrointestinal systems. Approximately 40-50% could affect the brain/nervous system, immune and cardiovascular systems, and the kidneys; 37% could affect the endocrine system; and 25% could cause cancer and mutations." Approximately 37% of the chemicals studied were volatile and vaporize into the air increasing risk of exposure to the workers at the drill site and also the surrounding public. More than 89% of the volatile chemicals can affect the eyes, skin sensory organs, and respiratory tract. High percentages of the volatile chemicals can also harm the brain and nervous system, the cardiovascular system, and the kidneys. As discussed below, the used fracturing fluid is often stored in open pit ponds and these chemicals can easily volatilize and become airborne. This supports the claims of people who report that the nearby drilling operations have caused their children to get headaches and nosebleeds in addition to other ailments.[18] Another source of hazardous materials is the shale which often contains radium, uranium, barium, chromium, zinc, and arsenic. These metals are bound to the shale and are released during the gas extraction process. They accumulate in the fracturing fluid wastewater and are brought to the surface.[16] Toxic brine solutions are also brought to the surfaces which have to be disposed of properly. Disposal of the used fracturing fluids can present a problem as discussed below.

Fracturing Fluid Disposal

Approximately 25-30% of the fracturing fluid injected is recovered while the balance is trapped underground. The recovered fracturing fluid is typically stored in onsite containment ponds. Heavy rains and tears in the pond liners can cause these sites to overflow and leak onto nearby land and possibly seep into the groundwater below. Waste ponds can also be detrimental to birds and other wildlife which mistake them for bodies of water. Hydrocarbons in the water can quickly trap insects. They in turn attract small birds and mammals that then get stuck. This in turn attracts larger birds that fall the same fate. A report published by the U.S. Fish & Wildlife Service in 2009[19] discusses bird mortality in oilfield wastewater disposal facilities. Although the article is specifically addresses oilfield wastewater, there are similarities between that water and fracturing fluid wastewater. Surfactants, which are used in both industries, reduce the surface tension in the water. They in turn allow water to penetrate birds' feathers. This can compromise the insulation properties of the feather and also cause the birds to become water logged and drown. Brine is also common to both industries. If salt is ingested from drinking the water or when cleaned off of the bird's feathers, it can be lethal. As little as 4 grams of salt can kill a bird.[19] In addition, if the brine evaporates and leaves salt deposits on the bird's feathers, it can affect their buoyancy and also their thermoregulatory system. This can cause them to drown and die from hypothermia.[19]

A seemingly simple solution to this problem is to cover the pond with a liner or store the fluids in containers. However, in many instances the fluid is never removed from the site and is left in the pond until it evaporates. In some states the pond is then allowed to be buried along with whatever chemicals are left behind. Another often utilized method of disposal is the injection of the fluid into designated waste-water wells several thousand feet below ground. These wells can have the same problems that any other well can have regarding structural failure. There have been cases in California, Louisiana, and Oklahoma where contaminants were coming up through the ground.[20] Oftentimes, specifically in the Marcellus shale play, recovered fracturing fluid is treated at municipal wastewater treatment facilities due to the lack of deep injection wells. Typically these facilities are not designed to handle radioactive materials and high levels of total dissolved solids (TDS) contained in the spent fracturing fluids. Because of this, many of the chemicals end up being discharged into surface waters after treatment at the facility. Some of these waterways provide drinking water.[21] This may seem like an egregious violation of law but due to the Solid Waste Disposal Act Amendments section 3001(b)(2)(A) the waste generated from fracking is exempt from hazardous classification.[22]

Finally, there is the potential of things going wrong at the surface. Handling millions of gallons of fluid in sensitive areas is risky. Pipes, fittings, seals, valves… all of these and other equipment have the potential to fail. Although this is not unique to fracking, proper handling of the fluids and chemicals and also maintenance on the equipment is critical. Besides the fracturing fluid, there are also oils and lubrication fluids, fuel to operate equipment, and other chemicals that are utilized at the drilling site. All of these fuels have the potential to be spilled as well.

Seismic Activity

The disposal injection wells have been linked to seismic activity. A series of earthquakes in Youngstown, Ohio was grouped around a wastewater well that was injecting into a fault whose location was previously unknown.[23] A 2012 study by the U.S. Geological Society found that the average rate for earthquakes in the midcontinent was about 20 per year. This increased to 29 in 2008, 50 in 2009, 87 in 2010, and 134 in 2011. The locations of the quakes were bunched together near wastewater injection wells.[24] A study conducted between November 2009 and September 2011 set up temporary seismographs covering a 43 mile grid that included the Barnett shale play in Texas.[25] Of the seismic events recorded, 67 were within the Barnett shale play, the focus of the study. Only 8 of the 67 events were recorded by the United States Geological Society (USGS). This indicates that many seismic events may go unrecorded. In addition, the study looked at the proximity of the events in relation to disposal injection wells. Eight epicenter groups were identified and each of these groups were located within 1.9 miles of one or more active injection wells with 6 being within 1.2 miles. All of these wells were actively being injected prior to the detection of the events and had a monthly injection rate of over 150,000 barrels of water (BWPW). However, in the area of study, there were 161 injection wells with the same rate of injection and over 90% of them did not have any seismic activity nearby. The author concludes although injection rate may increase the likelihood of a seismic event, the geology of the subsurface plays the primary role in whether or not injection will result in a seismic activity. Figure 3.1 shows the earthquake epicenters (red circles, size of circle determining strength), injection wells (squares and + symbols), and mapped faults (green lines). The yellow squares are wells which had a monthly injection rate greater than 150,000 BWPW, white squares exceeding 15,000 BWPW, and + symbols exceeding 1,500 BWPW. It can be seen that although many of the epicenters are clustered around high rate injection wells there are also many injection wells with no epicenters.

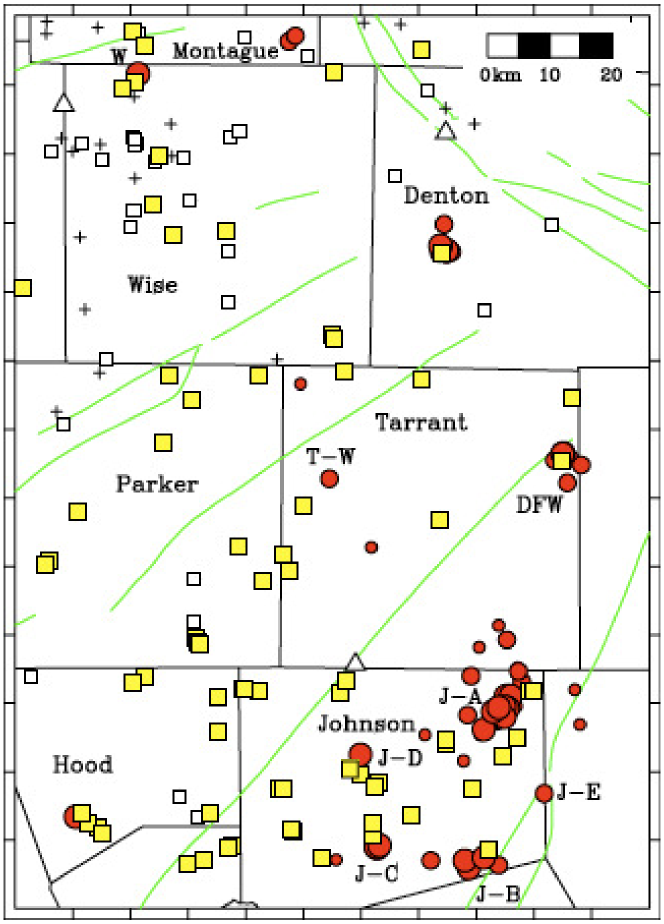


Figure 3.1 Map of the northeast corner of the Barnett shale play[25]

Migration into Groundwater

There are also concerns that fracturing fluid will end up in the groundwater. As the wells are drilled, they pass through aquifers. The annular space between the well borehole and well casing is filled with concrete to create an impermeable barrier between the fracturing fluids and its surroundings. However, a well is only as good as the concrete installed. Faulty concrete will crack and allow the fracturing fluid to escape the borehole and potentially enter into the aquifer. Archer, a well drilling company, estimated that 38% of wells worldwide (natural gas and others) have integrity issues. Of these, 40% are at risk of uncontrolled discharge.[26] There is also the possibility that newly drilled wells will intersect with old abandoned wells or create unknown fissures. Both of these would give the fracturing fluid an opportunity to migrate into the surrounding aquifers.

Based on a study by Warner et. al.[27] there is evidence in Pennsylvania that there are already natural pathways for materials to migrate from the deep shale formations into overlying aquifers. The idea that the fracturing fluid or the heavy saline solutions it disturbs could migrate into aquifers is often dismissed because fracturing is typically taking place at depths much deeper than the aquifers. In Pennsylvania for example, aquifers are typically found around 300 feet and fracturing taking place around 1000 feet. The researchers studied 426 water samples collected from the three major aquifers in Pennsylvania for different geochemistry and also isotropic tracers.[27] They compared this data to new and previously published data on 83 groundwater samples from deeper formations containing the heavy brine solutions. The collected samples were divided into four different groups based on salinity (the total amount of dissolved salts) and the molar ratios of Na/Cl and Br/Cl. Groups C and D both had elevated levels of salinity (Cl >20 mg/L) but group C had distinctively low Br/Cl ratios and higher NO_3^- concentrations which are typical of domestic sources such as road salt and wastewater. Group D had a relatively high Br/Cl ratio and low Na/Cl ratio which is similar to the deep saline samples analyzed. Of the 426 samples, 83 fell into Group D. The location of Group D samples typically were taken from wells at lower elevations and closer to valley centers but did not have a relationship with the closest shale gas wells. This indicates that it is unlikely that fracking was involved in the migration of the saline solution into the aquifer but instead it was a natural process that occurred over many years. Several other studies from west Texas, Michigan, Israel, and Canada have all documented the ability of deep saline solutions to travel into shallower aquifers. However, because the exact pathways that are created during fracturing are unknown, there is the possibility that fracking enhances the natural pathways and allows more of the saline and possibly fracturing fluid itself into the groundwater.

Methane Release into Water

In addition to drilling fluid being released into the water via faulty well casings, methane itself can also be released into the groundwater. Although methane is not unsafe to drink, it can buildup in wells and cause explosions. In the many rural areas of Pennsylvania private groundwater wells are very common for both household and agricultural use. Most of these wells are unregulated and not tested so it is difficult to tell if methane discovered in groundwater post fracking is a result of drilling activities or naturally occurring. It was already shown that natural pathways exist for the deep brine solutions so it is natural to think that they exist for methane as well.

Osborn et. al.[28] studied groundwater from 68 private wells in Susquehanna County, Pennsylvania. The study looked at wells that were within active drilling areas, defined by having at least one or more gas extraction wells within 1 km versus those in nonactive areas. Methane was detected in 85% of the wells regardless of whether or not they were in an active area. However, the concentration of methane was 17 times higher on average (19.2 mg/L) within active areas. According to the Department of Interior, the defined action level for hazard mitigation for methane is 10 – 28 mg/L. Methane is not uncommon in groundwater, however there is a difference between the methane commonly found in groundwater and methane recovered from deep wells. Biogenic methane, created from organic material as it decomposes, is found in shallow areas where groundwater wells are typically drilled. Thermogenic methane is created from the thermal decomposition of organic materials and is found deeper in the earth. Typically thermogenic methane is associated with oil and gas development while biogenic is not. Analytic methods are available that can determine the difference between these two types of methane.[29] In analyzing the samples Osborn[28] differentiated them into the two different types of methane. They found that the samples in the active drilling areas were more consistent with thermogenic methane indicating it originated from drilling activities.

These findings are disputed in a study from Molofsky et. al.[30] who ascertained that the data from the Osborn study was misinterpreted. They analyzed samples from over 1,700 water wells that had been collected prior to drilling, but within 2,500 feet of a shale gas well that has since been drilled. They assert that the discovery of methane in the groundwater has to do with the topography of the land rather than drilling activities. Water wells located in lowlands comprised 51% of the total wells studied but contained 88% of the wells with concentrations of methane above 7,000 ppb which is the current methane action level for water wells by the Pennsylvania DEP. They found a statistical difference between wells located in lowland vs. upland locations. They cited another study from 2006 from West Virginia that supported the same conclusion.[31] They believe that the thermogenic methane discovered in the shallow subsurface could be related to two geologic sources. The first are natural occurring faults and fractures which act as weak points in the creation of valleys that have allowed the themogenic methane to migrate to the shallow subsurface. This is seen at the Salt Springs State Park where a thermogenic methane gas seep is located at the surface. The second are deposits of thickened material that confine the thermogenic gas to the area. The group expanded the study by dividing the sample locations into those that fell within one kilometer of a gas production area vs. those that did not. They found that the methane concentrations in the active vs. non-active locations showed no statistical difference. They again cited another study[32] in November 2011 that sampled wells in Pennsylvania before and after drilling and fracturing activities in the area that found no statistical difference between the two sets of data.

In the Warner study discussed above,[27] they also compared the methane data from the Osborn study.[28] The samples with the highest average methane concentrations were found in the Group D samples, the group containing brine typical of deep water brine. Out of the 41 samples taken by Osborn, only one presented elevated (>10 mg/L) levels of methane greater than 1 km away from a shale gas well. Within 1 km, eleven samples had elevated levels across the different salinity groups from Warner. Three of the Group D samples had methane concentrations ranging from 2-4 mg/L in wells >1 km away from a well. This suggests that the methane in these wells could also be naturally derived, similar to the brine solutions.

In the movie *Gasland*, they featured three landowners whose properties were allegedly contaminated by oil and gas development. The State of Colorado Oil & Gas Conservation Commission (COGCC) investigated complaints from the landowners in 2008 and 2009 prior to the movie being released in 2010. Of the three investigations, one led to the discovery of a mixture of biogenic and thermogenic methane. The landowner and well operator reached a settlement for the damages. The other two investigations led to findings of biogenic methane only, which is unrelated to gas drilling and extraction activities. Both of these wells extract water from the Laramie-Fox Hill Aquifer which is known to have contained elevated levels of methane prior to shale gas drilling activities in the past decade.[29] One of the wells containing the biogenic methane supplies the methane laden water that is star of the water ignition scene. The movie also focuses on two issues in the West Divide Creek area in Colorado. There are two methane seeps that are geographically close but the methane is derived from different sources. The first seep, called the West Divide Creek gas seep was investigated in 2004 by the COGCC and determined to contain thermogenic methane resulting from a gas well that had faulty cementing. The other well, approximately 1,500 feet away has been sampled in 2004, 2007, 2009, and 2010. In each instance the samples contained biogenic methane only, unrelated to gas drilling.[29] During the filming of the movie, COGCC director Dave Neslin attempted to speak with the movie's producer to discuss the technical issues behind these claims and discoveries but was denied. Although the movie brought hydraulic fracturing and gas extraction into the limelight, it unfortunately did so in a one-sided story inaccurately portraying some of the facts.

Emissions

Natural gas has been promoted as a "bridging" fuel to a safer, cleaner, and lower carbon future. The abundance of fuel right here in the United States can help it become more energy independent. On the surface it also appears that natural gas will reduce greenhouse gases. From source to use, natural gas emits 297 grams of CO_2 for every kilowatt-hour of energy it produces compared to gasoline which emits 334 grams.[33] Lower emissions are true not only for gasoline but also other fuels natural gas commonly competes with. Analyzing only the data in Table 3.1 it appears that natural gas is an obvious choice as a replacement to other types of fuel. It has the lowest CO_2 emissions of the most common fuels. However, CO_2 emissions is only one factor in determining if natural gas is truly a cleaner fuel in terms of its overall effect on the environment.

$$q_{CO2} = \left(\frac{c_f}{h_f}\right)\left(\frac{C_{CO2}}{C_m}\right)$$

where:

q_{CO2} = specific CO_2 emission (kg_{CO2}/kWh)
c_f = specific carbon content in the fuel (kg_C/kg_{fuel})
h_f = specific energy content (k_{Wh}/kg_{fuel})
C_m = specific mass carbon (kg/mol_{Carbon})
C_{CO2} = specific mass carbon dioxide (kg/mol_{CO2})

Table 3.1 Comparison of CO_2 emissions per kWh for various fuels[34]

Fuel	Specific Carbon Content (kg_c/kg_{fuel})	Specific Energy Content kWh/kg_{fuel})	Specific CO_2 Emission (kg_{CO2}/kg_{fuel})	Specific CO_2 Emission (kg_{CO2}/kWh)
Coal	0.75	7.5	2.3	0.37
Gasoline	0.9	12.5	3.3	0.27
Light Oil	0.7	1.7	2.6	0.26

Diesel	0.86	11.8	3.2	0.24
Liquid Petroleum Gas	0.82	12.3	3.0	0.24
Natural Gas	0.75	12	2.8	0.23

A broader analysis of the greenhouse gas effects of methane considers many other factors besides the CO_2 created from combustion which is only a small part in the big picture. Methane, the primary component in natural gas, has a much larger global warming potential (GWP) than CO_2. But because methane has a relatively short atmospheric lifetime, 12 years, it is difficult to compare the GWP of methane to CO_2. GWP, a method used to compare the effect of different gases on global warming, is usually a comparison of a particular gas to CO_2 represented as a ratio of the cumulative radiative forcing *t* years after emission of a gas to the same of CO_2. Based on the GWP of methane over 20 years, it is 56 times worse for the atmosphere than CO_2. However, over 100 years the ratio becomes better at 21.[35] Being able to only look at a single point in time is not only a limitation of the GWP but also confusing. Alvarez et. al.[36] realized this and created the technology warming potential (TWP), an extension of the GWP that overcomes its limitations. They then applied the TWP to real world situations. For example, they looked at converting a fleet of gasoline cars to natural gas. Because of all the estimated methane leakage from the production of the gas and from burning the fuel itself, radiative forcing increased for 80 years before any benefits are realized. With this perspective, converting cars to natural gas will be more detrimental to global warming than sticking with gasoline vehicles. The effects are even worse when looking at heavy duty diesel vehicles. Looking at the GWP itself also leads to this conclusion. Even with the current estimated reserves stated above and the average annual consumption of natural gas (which will only increase if this is the path taken) there is only about 40 years worth of natural gas. Because of this and assesments like Alvarez's, it is important to realize that the application of natural gas as a bridging fuel must be applied to the right markets, those where the benefits will be fully realized.

To evaluate the entire green house gas (GHG) footprint Howarth et. al.[37] studied the whole process of the natural gas extraction via hydraulic fracturing. The GHG consisted of three items: direct emissions due to combustion at end use; indirect emissions from the other fuels used to extract, refine, and transport the gas; and fugitive emissions of methane. Even though there is an immense amount of industrial activity required to extract the gas, the indirect emissions are small (1 to 1.5 gC/MJ) in comparison to the direct emissions (15 gC/MJ). However, the fugitive emissions are considerable. There are several sources for fugitive emissions. The first is in the recovered fracturing fluid itself. There is a large amount of methane that also comes to the surface during the flowback of this fluid. They estimated between 0.6 to 3.2% of the well's lifetime production of methane is lost during the initial flowback time period. Admittedly the data is limited on this and the data that is available is not well documented, so they assumed a mean value of 1.6% of the well's lifetime production of methane is lost during initial flowback. More methane is lost during the drill out phase of the well installation. Using EPA estimates, they conclude that 0.33% of methane is lost during this phase. Based on this, they determined that 1.9% is lost during the installation of the well. As with the fracturing fluid, there are many pieces of equipment associated with the gas itself and between 55 to 150 connections of hoses and pipe to the different equipment. In addition to leaks there are pressure relief valves that are designed to release methane. Some of the gas extracted needs to be processed; there are additional losses here. The transport, storage, and distribution of the gas can all create more fugitive gas. Overall, they estimate that between 3.6 to 7.9% of the total production of the well is lost through fugitive emissions.

In 2007 researchers from the National Oceanic and Atmospheric Administration (NOAA) first started noticing elevated levels of natural gas in the air at an air monitoring tower north of Denver, CO. They determined the direction of the pollution and began to monitor the region in real time via mobile monitoring equipment. They eventually ended at the Denver-Julesburg gas play where over 20,000 oil and gas wells have been drilled. After compiling their data they determined that approximately 2.3 – 7.7% of gas is lost over the lifetime of the wells. This data is consistent with Howarth's team's conclusions. The EPA currently estimates the losses to be 2.8% which is at the low end of both Howarth's and NOAA's assessments.[38]

However, shortly after publication, Howarth's assessments were challenged by Cathles et.al.[39] They had several issues with Howarth's analysis. One of which is the use of the 20 year GWP. As demonstrated above, GWP, although commonly used, creates problems of its own. Cathles suggests that the 100 year GWP should be used because we will be living with the effects of greenhouse gases for a very long time. They critized Howarth's assessments of leakage rates as "implausibly" high. In regards to the initial venting of methane after drilling utilized to clean the well, Cathles says that not only would it be unsafe to release the amount of methane Howarth suggests, but it would be financially irresponsible for the gas company to do so. Howarth et. al.[40] published responses to Cathles challenges that defended their original analysis and reiterated their conclusion that "shale gas is not a suitable bridge fuel for the 21st Century". They stated that only when the price of natural gas is at about $4/thousand cubic feet will gas companies break even on capturing the blowback gas. As will be seen below, the price has been hovering in the $4-5 range for the past few years. They also compare several other published estimates for methane emissions and assert that the 20 year GWP is particularly important because of the immediate need to avoid "climate-system tipping points".

Finally, fluids accumulate in older wells creating back pressure and blocking the gas from being extracted. The wells are periodically blown out to remove this fluid which release substantial amounts of gas into the air. This removal can happen up to several times per day.

All of these fugitive emissions can wreak havoc on the local communities or landowners. There are reports of people becoming dizzy, getting headaches, burning eyes, and nosebleeds. Air quality has been sampled around some houses near drilling sites and elevated levels of volatile organic compounds (VOCs) were found. In addition to the fugitive emissions themselves, there is also the effect of the methane mixing with the exhaust from diesel fuel emissions and creating ground level ozone. Exposure to ozone is particularly harmful to the lungs and can cause asthma and chronic obstructive pulmonary disease. When ozone mixes with particulate matter it creates smog which also leads to health issues.[17] In addition, ozone is harmful to crops commonly grown in the western United States.

Other Concerns

There are other impacts to consider. Since the cost of natural gas is so low, viable alternative resources for electrical generation will not get utilized and advances in these technologies will be set back years. Although renewable resources still have a long way to go in regards to technology and cost, until now, nuclear power has been able to compete with traditional technologies. However, since the natural gas boom has driven prices of natural gas (for electricity generation) from averages of $7-$9 per thousand cubic feet to an average of $4.87 in 2010 and an all time low of $2.85 in April 2012, nuclear power cannot compete. The cost to generate electricity from a gas fired plant at this price is $0.03/KWh. In 2009 this cost from nuclear power was $0.08/KWh and will be above $0.07/KWh through 2025. Even if natural gas prices rise to $4.50 per thousand cubic feet as the market suggests, the cost to generate electricity is $0.05/KWh[41], still below that of nuclear power. Although nuclear power has its own issues, it has the lowest greenhouse emissions for electricity generation.[42] It is important to realize that even with the large reserves of natural gas, it is still a limited resource and it is critical to keep researching and investing in other fuel sources. This of course extends to nuclear power because uranium is also a limited resource, but it is estimated there is enough uranium to operate the world's current nuclear power generators for the next 200 years.[43]

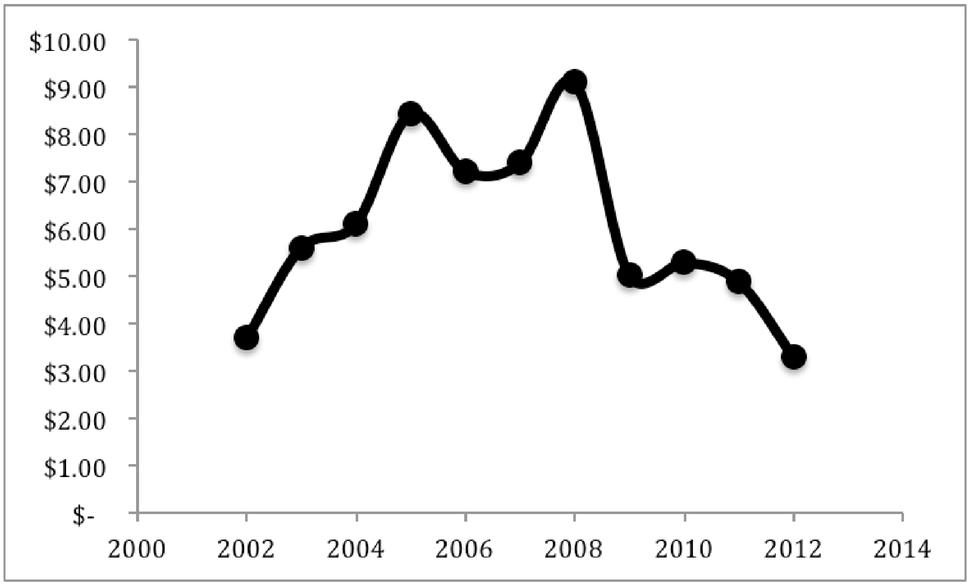


Figure 3.2 Historical natural gas prices for electrical generation[44]

In addition to cheap natural gas being a strong competitor against nuclear and renewable generation processes, it can also compete with itself. The low price of natural gas is great for consumers but not for the industry. With prices as low as they are in 2012, operators cannot cover the cost to drill and operate wells. As a result, drilling companies are exporting the gas to foreign markets where the supply is not as high and the opportunity to make more money exists. Although we are exporting the same gas that is helping us achieve energy independence it will also bring the cost of natural gas in line as supply and demand level out.

Chapter 4 - Solutions

In 2011 a Canadian drilling firm began utilizing a liquefied propane gas (LPG) instead of water to fracture the shale. The LPG is almost 100% recoverable because it converts back to a gas underground that readily returns to the surface. The gas does not extract the radioactive minerals or brine that the water from hydraulic fracturing does. The propane can be sold or reused. LPG also does not require nearly the volume that hydraulic fracturing needs. This reduces the number of trucks on the road delivering materials, the drill site staging area, and the general carbon emissions as well. By eliminating the water, the holding ponds, and the disposal of the fracturing fluid are all eliminated. The switch to LPG is difficult because it is initially more expensive and much of the infrastructure is not in place. In addition, LPG is highly flammable and explosive. The trucks that were once carrying water through town are now carrying an extremely explosive material. In January 2011 there was a fire at a drill site utilizing LPG, the result of leaking propane gas. The company has since added additional propane sensors and infrared technology that allows workers to detect the gas.[45]

Wastewater tanks could be utilized for the spent fracturing fluids which would also eliminate the ponds and eliminate their associated problems. The drillers could be required to place a signatory tracer in their fracturing fluid. This would not be a preventative measure but would at least hold companies culpable if fluids turned up in unwanted places.

“Green completions” can be utilized by well installers. Instead of simply venting the gas at the end of drilling operations in order to “clean” the production zone of the well from remaining drilling fluids and sand, portable equipment can be installed that will clean up the initial gas and allow it to be recovered.[46]

Plunger lift stations can be installed to remove excess fluid buildup in the wells. The lift stations essentially act as an elevator that is dropped down into the well below the accumulated fluid. The plunger is then lifted up by the pressure of the gas accumulated under and the fluid is recovered through one line and the gas is extracted through another. A basic plunger lift system costs between $1,900 - $7,800 to install. A plunger lift system can increase well production anywhere from 4,700 to 18,250 thousand cubic feet per year in a particular well. Depending on the price of natural gas at the time the plunger system can pay for itself in as little as 1 – 12 months.[47]

Triethylene glycol (TEG) is utilized in dehydrators to extract water from the natural gas after it is extracted. TEG is pumped into a contactor with the recently extracted shale gas. The TEG absorbs the water from the methane so that it will meet the standards needed for sale. TEG also absorbs VOCs, HAPs and some unintended methane. The TEG is recycled and then regenerated with heat. The heat vaporizes the water and also the VOCS, HAPs and methane. These gases are then vented to the air while the TEG is pumped back into contact with extracted gas. In addition, the dehydrators and circulation rate of the TEG are designed for initial well production. As wells age they produce less natural gas. The amount of unintended methane absorbed in the TEG is directly proportional to the circulation rate of the TEG. As less gas is extracted from the well the circulation of TEG could be decreased thereby decreasing the amount of methane that is unintentionally absorbed and released into the atmosphere. It has been found that TEG circulation rates are often 2 or more times the amount they need to be. Flash tank separators can also be installed to separate the gas from the liquid. Flash tanks are installed in decreasing percentages of wells as the rate of production of wells goes down. They are seen as only necessary on the larger wells in order to recover the methane being lost. Approximately 90% of the methane and 10-40% of the VOCs can be recovered with a flash tank separator. Reducing the TEG circulation has an immediate payback and the flash tank separators typically payback in 4-11 months.[48] Even further, glycol dehydrators could be replaced with desiccant dehydrators. These are closed units with dry desiccant that absorb the water from the gas. Because they are a closed system, there is no emission to the atmosphere until the desiccant needs to be replaced.

Many of the pieces of equipment at the drill site burn natural gas to provide process heat. Much like a furnace, they rely on a pilot light, which can be blown out by gusts of wind. The result is gas emission until the pilot is relit. BASO® valves eliminate this issue by closing when the accompanying thermocouple senses there is no longer heat from the pilot light flame. BASO® valves are easy to install at around $100 per valve and can save up to 200 thousand cubic feet of gas per year per valve.[49]

Stronger and more routine maintenance programs need to be implemented at the drill sites in order to verify and reduce fugitive leaks from equipment. Inspections of flowlines can identify small leaks before they get larger. Composite wrap can be used on non-leaking issues in pipes such as dents and corrosion. The wraps are easy and inexpensive to install and can prevent the defect from getting worse and potentially leaking. Infrared surveys can be performed to show companies where the natural gas is leaking. The surveys can be performed from a helicopter or with a handheld camera. Ultrasound can be used to listen for small leaks via the high frequency sound that leaks through valves. All of these options are available to gas companies and will reduce fugitive emissions. In addition they will save the gas company money in the long run.

Eliminating fracturing along known faults can prevent earthquakes. Drillers could also implement a "stop light" system that would monitor seismic activity during drilling and fracturing operations. If seismic activity began to increase they could shut down activities and evaluate the situation.[50]

Chapter 5 - Further Recommendations

Jackson et. al.[51] present several research recommendations to minimize the impacts of hydraulic fracturing and shale gas extraction. The first is to determine what, if any, are the health impacts of methane in water. Methane is not typically construed as a health hazard except for in the cases of explosion and asphyxiation. However, there has been no real research to determine if this is actually true or not. Another recommendation is to create a national database of methane and other hydrocarbons in water. This would aid in determining if there was already methane present in the groundwater before fracturing in occurred in a specific area. They call to further refine the actual amount of greenhouse gas emissions associated with gas extraction. As seen above, the reports that have been published on this topic have been seriously debated and there is no agreement as to what is correct. Until this is known, it is difficult to determine if natural gas can be the great bridging fuel. Finally, they suggest to study the different methods of fracturing fluid disposal and determine what the long term impacts of disposal are, regardless of the method. Finally, research into the degradation of the fracturing fluids could also prove to be valuable. Knowing if they degrade biologically or chemically, what their lifespan is, and what and how they react with their surroundings in the subsurface will tell us how much of a concern the chemicals are after they have been injected or buried.

Chapter 6 - The Benefits

All is not doom and gloom regarding hydraulic fracturing and shale gas extraction. It is true that the industry brings needed jobs to struggling economies. Ohio and Pennsylvania have lower than national average unemployment rates and have also dropped to state lows as a result of the shale gas boom in the Marcellus play. The economic impact of natural gas development results from spending between businesses and also from royalties and land leases granted to land owners. Goods and services are required for the exploration of the land, drilling, processing of the natural gas, and transportation of the gas. Many different trades and industries are required for these services such as construction, engineering, trucking, and heavy manufacturing. The leases and royalties not only generate income for the landowner but also generate revenue via taxes for the government.

A study in 2010 evaluated the economic impact of Marcellus play in Pennsylvania. It found that in 2009 gas producers spent $4.5 billion to develop the region resulting in $3.9 billion in value added. This generated $489 million in state and local taxes along with over 44,000 jobs. It is projected that by 2020 the industry will have generated over $18 billion in value added to the economy with $1.8 billion in taxes and the creation of over 200,000 jobs.[52] The Haynesville shale in Louisiana is reported to have cancelled out the recession of the past few years. In 2009 it led to $6.3 billion in business and household earnings, over 32,000 jobs, $80 million in local taxes, and $69 million in state taxes. In 2010 the numbers jumped to $16.3 billion, over 57,000, $339 million, and $574 million, respectively.[53] In New York, a study in 2011 estimates that if policies are put into place that encourage natural gas exploration and drilling that by 2015 there would be an increase of over 47,000 jobs and $83 million. By 2030 the numbers would increase to 64,000 jobs and $456 million in revenue. Because of shale gas North Dakota is now the 2nd largest oil producer in the country and in turn reduced its unemployment rate to 3% while increasing state income. More than 100,000 jobs directly related to natural gas drilling and over 400,000 jobs indirectly related have been created since 2008 in the U.S.[54]

As discussed previously, the shale gas boom has brought on cheaper natural gas prices. Natural gas is one of the most widely used fuels in the country; it is used in the residential and commercial market for heating and cooking. It is the second most used energy source in industry. Industries from pulp and paper, chemical, metals, food processing, and petroleum refining all utilize natural gas. It is used as a feedstock for fertilizers, pharmaceuticals, and other chemical products. Cheap natural gas could allow companies to be more competitive at manufacturing in the United States. Many cities have converted their public transportation systems and government vehicles to natural gas driven vehicles. Many power plants utilize natural gas to generate electricity. As the prices of natural gas go down due to shale gas extraction, it becomes cheaper for the end user in all of these uses. In general, society benefits as a whole as a result of inexpensive natural gas.

Chapter 7 - Politics

The political sky is littered with opinions on hydraulic fracturing and shale gas, both supporting and opposing. In April 2012 the White House issued an executive order that coordinates thirteen different federal agencies. Their purpose is to review, study, and propose on new regulations surrounding hydraulic fracturing. They will ensure that the federal government has a consolidated voice on the issue. President Barack Obama has also touted natural gas by saying it will create 600,000 jobs and cut our energy dependence in half by 2020. A rule was proposed that would require drilling companies to disclose the chemicals utilized in fracturing fluids. Initially the rule required the disclosure prior to drilling but after pushback from industry and lobbyists it was amended to allow them to disclose after drilling activities. With the economy in a slump it would be difficult for a President to not be in support of shale gas extraction.

Chapter 8 - Regulations

Currently hydraulic fracturing is regulated at the state level. This may be the best place for regulation because the gas fields in each individual state are particular to that state. The best techniques for extraction and the regulations surrounding them are best left to the regulators in each locality. In 1997 there was a push by the Legal Environmental Assistance Foundation (LEAF). They proposed a lawsuit and the 11th Circuit Appeals Court issued an opinion arguing that by definition fracturing fluids are being injected and should be regulated under the Safe Water Drinking Act by the EPA.[55] However, in 2005, Congress passed the Energy Policy Act. This exempted fracking from the Safe Water Drinking Act (SWDA) unless it involved diesel fluid and since then regulation has been completely up to the states. This was convenient timing for the industry as the fracturing boom was just beginning. There are several bills pending that will affect the future of fracking if passed. H.R. 1084 and S. 587 would repeal the exemption from 2005 and include the injection of fluids used in hydraulic fracturing activities to be regulated under the Safe Water Drinking Act. They will also require full disclosure of the chemicals used in the fracturing fluids. The Fracturing Regulations are Effective in State Hands Act (FRESH), H.R. 4322 and S. 2248 would put the regulatory control completely in the hands of the states even if it is federal land within the state. The regulation of fracking under the SWDA would likely benefit the environmental concerns surrounding fracturing. It would have the most benefit to groundwater protection and public health in states that have relatively weak regulations in regards to groundwater protection. Even though there would be benefit to regulation by the EPA, the SWDA would not have any effect on the treatment and disposal of spent fracturing fluids, surface management of fluids and chemicals, or methane venting.[56]

Because regulation is at the state level there are several different regulations ranging from well permitting requirements, disclosure of fracturing fluid ingredients, and specific zoning requirements. Several states, Texas, Oklahoma, Arkansas, North Dakota, and Louisiana have developed regulations that require disclosure of the chemicals being utilized in fracturing and well permitting requirements. In Texas there are even local ordinances which allow oil and gas drilling on commercial and industrial zoned areas but not in residential zones or within 500 feet of a residence regardless of its zone. New York currently has a moratorium on any hydraulic fracturing activities. They are weighing the opinions of over 40,000 comments made by the public and are trying to work regulation into the existing Department of Environmental Conservation who has jurisdiction over well drilling. This is a very proactive approach as opposed to a state like Pennsylvania that has taken a more reactive approach due to the policies or lack thereof they have had over the years.[57]

Even though local regulation may seem to be the way hydraulic fracturing should be regulated, it can also have drawbacks. Specifically in rural New York many communities have zoning in place to enact regulations described above. They have been enacting zoning ordinances and laws to control fracking. However, several lawsuits have arisen with the plaintiffs stating that they preempt the zoning laws that have been put into place. The time New York spends in determining the role of local and state government could pave the way and create an ideal model for other states to follow.[57]

In Pennsylvania, where deep water injection wells are scarce, the state asked drillers to stop taking their wastewater to facilities that are unable to handle the waste properly. This resulted in many of the federally overseen facilities to voluntarily stop accepting the waste and in turn there are no facilities that currently accept the waste that discharge into public waterways. In addition to regulatory agencies taking action, citizen groups have been doing the same. The Clean Water Action Group, formed in the 1970s to raise awareness around environmental issues, have threatened to file suit against one wastewater treatment facility and have filed suit against another in order to force them to stop treating wastewater from fracking. The first suit never came to fruition because the facility agreed to stop accepting the waste.[58]

Although regulating hydraulic fracturing is important, companies need to take responsibility for what they are doing. In some instances, doing what is right by the environment will also improve their bottom line. As advisers to the U.S. energy secretary stated last year, “If action is not taken to reduce the environmental impact there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity”.[59]

Appendix A - Types of Chemicals Used In Fracturing Fluids[14]

Chemical Name	**Chemical Purpose**	**% by Volume**
Friction Reducers	Reduce friction pressure	0.088%
Acids	Helps dissolve minerals	0.123%
Biocides	Eliminates bacteria	0.001%
Corrosion Inhibitors	Prevents the corrosion of the pipe	0.002%
Iron Control	Prevents precipitation of metal oxides	0.004%
Crosslinkers	Maintains fluid velocity	0.007%
Breakers	Allows delayed breakdown of the gel	0.01%
pH Adjusting Agents	Adjusts the pH to maintain fluid effectiveness	0.011%
Scale Inhibitors	Prevents scale deposits in the pipe	0.043%
Gelling Agents	Thickens the fluid	0.056%
Clay Stabilizer	Creates a brine carrier fluid	0.06%
Surfactants	Increases the viscosity of the fluid	0.055%

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