

**Frack Attack:
Weighing the Debate over the Hazards of Shale Gas Production**

Nicolas Casasanto

Jay Ague, Advisor

Michael Oristaglio, 2nd Reader

27 April 2012

A Senior Essay presented to the faculty of the Department of Geology and Geophysics, Yale University, in partial fulfillment of the Bachelor's Degree.

In presenting this essay in partial fulfillment of the Bachelor's Degree from the Department of Geology and Geophysics, Yale University, I agree that the department may make copies or post it on the departmental website so that others may better understand the undergraduate research of the department. I further agree that extensive copying of this thesis is allowable only for scholarly purposes. It is understood, however, that any copying or publication of this thesis for commercial purposes or financial gain is not allowed without my written consent.

Nicolas Casasanto, 27 April 2012

ABSTRACT

Shale gas is heralded by many as the “bridge fuel” connecting a fossil fuel-dominated generation to a renewables-dominated generation, and the industry has the potential to be an economic boon and provide jobs to many. It is also thought to be a “cleaner” fossil fuel with fewer, less potent emissions. However, shale gas production poses considerable risks. Fugitive emissions of methane during extraction operations and transport, storage, and distribution could range from 3.6 to 7.9% of the total lifetime production of a given well, though this estimate is debated. Given the extreme potency of methane as a greenhouse gas on shorter time horizons, it is possible that extensive methane emissions from shale gas operations could have greater global warming potential than carbon dioxide emissions from coal, risking breaching the hypothetical “tipping point” of climate change, beyond which point there is no return. If this is true, shale gas could lose its label as a “bridge fuel” between the coal of yesterday and the renewables of tomorrow. Such emissions also pose a hazard to human health, potentially causing headaches, diarrhea, nosebleeds, dizziness, blackouts, muscle spasms, and other problems in the communities in which fracking occurs. Also hazardous to human health and the local environment is the inadequate treatment and disposal of flowback, which contains hundreds of chemicals, organic compounds, heavy metals and other elements, salts, and radionuclides; many components are either carcinogenic or associated with numerous health problems. The high volumes of water used not only make treatment difficult, but also strain water resources. Additional contamination of water is likely in the migration of thermogenic methane to shallow groundwater, posing an asphyxiation and explosion risk. As so much of the shale gas industry and its operations go unregulated by the federal government thanks to legislative exemptions and exclusions, there is little to no oversight, resulting in a lack of responsible and safe practice. Greater regulation and transparency would help to mitigate the possible hazards presented by shale gas production.

1. INTRODUCTION

In his 2012 State of the Union address, President Obama pledged support for shale gas production, calling for the government to develop a responsible roadmap, adding that his administration supported “common-sense” new rules to protect the public. Said Obama, “America will develop this resource without putting the health and safety of our citizens at risk.” As expected, the industry was not pleased. The American Petroleum Institute fired back, claiming that the President’s approach to shale gas will do nothing more than slow production and increase costs (*Reuters*, 2012). This tension between government and industry is indicative of a greater struggle to objectively understand the true risks of shale gas production and what can and should be done to mitigate those hazards. Even in the scientific community, there is strong debate. While shale gas means jobs and revenue to some, to many unwilling or even unsuspecting citizens, it could mean health concerns from polluted water (Osborn et al., 2011a; Volz et al., 2011; Gregory et al., 2011; Colborn et al., 2011) and even accelerated climate change from methane leakage (Howarth et al., 2011; 2012). The merits of these concerns are the topic of debate not just in the media, but also in scientific literature. With so many conclusions and the well being of not only individuals but also the environment at stake, it is important to root out the reality of the threats posed by extracting shale gas.

Here, I provide a background on shale gas and its extraction techniques. I then discuss the major concerns regarding the two main modes of contamination: atmospheric and waterborne. Examining individual case studies helps to frame the context of these discussions in reality. Finally, I look to the future, outlining recommendations made by my own conclusions and those of the Department of Energy (DOE) (2011a; 2011b). There is abundant fuel held in these shale reservoirs, but too much haste to obtain it before completely weighing the consequences of such a process could be dire.

2. BACKGROUND

Before delving into the potential hazards posed by shale gas production, it is first important to understand what shale is, where it is deposited, why it serves as a reservoir for natural gas, and how industry goes about extracting such gas from these reservoirs.

2.1 The geology of shale

Shale is a siliciclastic sedimentary rock composed of silt and clay particles. Shales contain less silica (SiO_2) and more alumina (Al_2O_3) than do sandstones, reflecting the higher content of aluminum-bearing clay minerals in shales. For this same reason, shale has higher iron, calcium, sodium, and potassium contents as well (Boggs, 1987, p. 198). Carbonaceous shales contain high concentrations of residual organic matter derived from the partial decomposition of plant and animal remains, both terrestrial and aquatic (Boggs, 1987, p. 22). Shales can be borne of many environments, most typically of “marine environments adjacent to major continents at places where the seafloor lies below storm wave base” (Boggs, 1987, p. 215). By far the most important condition for the formation of shales is low water energy, which allows for suspension settling of fine silt and clay; thus, lakes, quiet-water parts of rivers, and lagoonal, tidal-flat, and deltaic environments are all likely settings in which shales originate. Because aluminous clays are derived mainly from the weathering of feldspars – the most abundant minerals in Earth’s crust – shales are the most abundant sedimentary rock, making up 50-60% of the sedimentary rock record. Shale units can range in thickness from millimeters to hundreds of meters and are often interbedded with sandstones or limestones (Boggs, 1987, p. 215).

Shale is quite similar to the rock of conventional gas and oil producing reservoirs, except that its grain size is much smaller than that of the sandstones of conventional reservoirs. Shale grains are about $3.9\ \mu\text{m}$ in diameter – a ϕ of 8 on the Krumbein scale¹ – whereas the sizes of grains comprising conventional gas and oil reservoirs typically range from about $60\ \mu\text{m}$ to 1 mm in diameter – a ϕ ranging from 4 to 0, respectively (Boggs, 1987, p. 107). This two- to three-orders-of-magnitude difference in grain size creates even greater disparity in a formation’s permeability, defined as the measurement of the ease of fluid flow through rock. While a conventional reservoir has a permeability of 10 millidarcies (md), the permeability of a typical shale gas reservoir is 100 nanodarcies (nd) – 1/1000 of 1% that of conventional reservoirs (King, 2011). Thus, producing gas from reservoirs of such low permeability requires a different, more advanced approach.

¹ The Krumbein scale is a logarithmic scale based on the relationship $\phi = -\log_2 S$, where ϕ is the scale and S is the diameter expressed in millimeters (Boggs, 1987, p. 107).

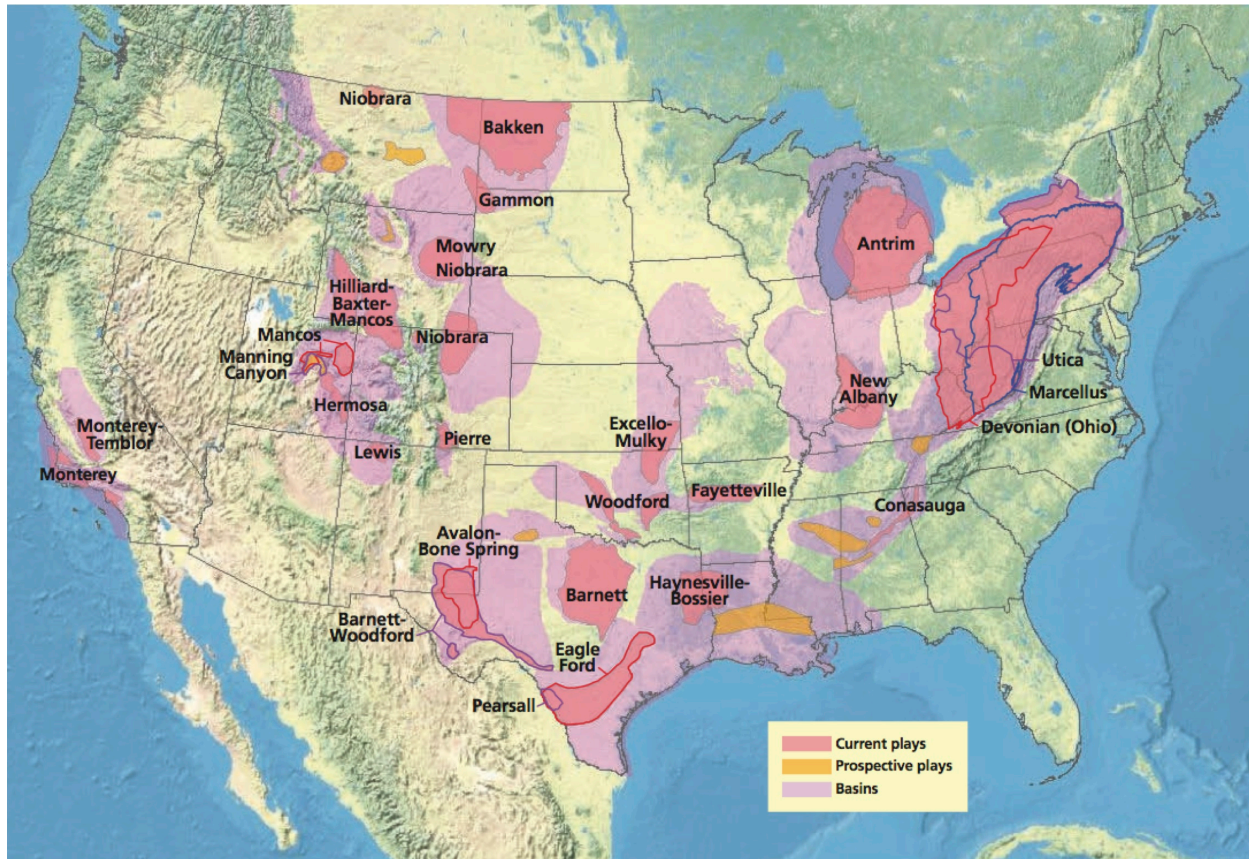


Figure 1: Domestic shale gas exploration as of 9 May 2011 (Schmidt, 2011; adapted from EIA 2011b).

Some shales have an even lower permeability approaching that of steel pipe, rendering them unproductive. These shales are rich in clay content and lack the characteristic natural fractures and micro-fissures that make gas and oil production possible; instead, these ultra-low permeability shales serve as natural barriers that seal any gas and oil in underlying reservoirs for the millions of years since deposition (King, 2011). In addition to entrapment in natural fractures and pore spaces, natural gas can be adsorbed onto minerals and organic material in the formation (Gregory et al., 2011). While ~90% of this gas is methane, reservoirs typically hold other hydrocarbons, CO₂, nitrogen, and H₂S as well (Gregory et al., 2011).

As mentioned above, shale is the most abundant sedimentary rock, and as such, there are basins, many of which are gas-rich, worldwide. The focus of this paper will be on domestic production, but for perspective, a recent report by the U.S. Energy Information Administration (EIA) assessed a select group of 32 countries, in which there are a total of

48 shale gas basins, containing almost 70 shale gas formations (EIA 2011a). Of those formations, 16 are established and emerging plays in the United States; Figure 1 details the locations of these domestic plays and their extents (EIA 2011b). These plays are concentrated in the Northeast, Gulf Coast, Mid-Continent, Southwest, and Rocky Mountains regions. According to the EIA, the U.S. has 862 trillion cubic feet (tcf) of technically recoverable shale gas resources. This comprises 13% of global estimates and makes for the highest national concentration, second only to China's 1,275 tcf, which is just over 19% of the global recoverable shale gas (EIA 2011a).

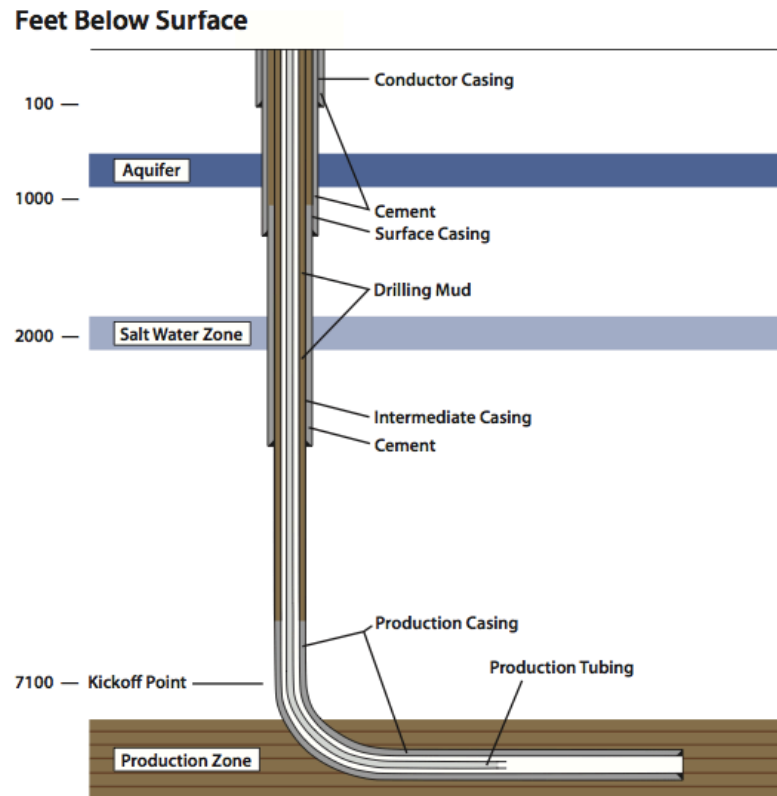
2.2 Well development and extraction

As stated earlier, the low permeability of shale gas reservoirs requires a more intensive approach. King (2011) provides a thorough description of this process, which I will summarize here:

Before any drilling begins, exploration of potential locations is done via wide area geologic studies, seismic interpretation, and petrophysical assessment of rocks and cores. When it is established where and where not to drill, negotiations take place for surface access and the leasing of mineral rights. Additionally, permits at the federal, state, and/or local levels must be obtained, which usually takes anywhere from months to years. Exploratory drilling then begins so that the composition of reservoir fluids can be assessed and productive capacity determined within a few weeks or months. If the well is found to be suitable, its construction is completed; this involves extending the vertical wells into their horizontal phase (discussed later) and performing casing and cementing operations to create a system of pressure barriers keeping the hydrocarbons within separated from outside water sources. Once the final casing strings are set, a wellhead replaces the blowout preventer. Methane is typically vented from the first wells in an area in order to determine typical well production rates so that the connecting pipeline can be properly sized.

Once the well is completed, hydraulic fracturing begins. It is by this process that the permeability of the reservoir is increased to create a flow path to the wellbore. It begins with the initial pumping of a frack stage, which lasts between 20 minutes to 4

hours. During this phase, the well will experience the highest pressures of its operation so as to force reverse fluid flow into the formation. This great pressure within the formation opens the natural fractures and creates new ones, producing a network of complex fractures, which King likens to that in shattered glass.



These fractures extend **Figure 2:** Typical shale well construction, not to scale (MIT, 2011).

vertically up to a few hundred feet, which is bounded by both the loss of frack fluid, which leaks into permeable formations, and rock barriers above and below the horizontal well region. The depth of a given well depends upon the local geology and fracturing experience, but most are generally at depths no less than 2000 ft., usually in the vicinity of 7000 ft.; see Figure 2.

For the first two to three weeks after fracking, frack fluids flow back at rates ranging from 3 to 6 barrels per minute (125 to 250 gallons per minute) for a few hours, falling to 29 gallons per minute (1000 barrels per day) within 24 hours, then further dropping over several days to a few hundred barrels per day by the end of the second or third week, and eventually falls to a few barrels per day within a few more weeks. As the first water is produced, methane production is absent, but the water rate will drop sharply as gas production begins. However much frack fluid is recovered on flowback is highly variable and depends on the formation; rates from 5% to 50% have been observed. This is due to the saturation of a given formation

with respect to water: most shale formations are under saturated to some degree and will absorb much of the frack fluid, which will not return to the surface unless displaced by gas pressure. This is beneficial to production, as this absorbed frack fluid acts as a propping agent holding open smaller fissures. Production ensues.

3. THE BENEFITS OF SHALE GAS

Proponents of shale gas production make a very compelling case with advantages that are hard to dismiss. One big talking point is the boon that shale gas can be to the economy. According to Engelder (2011), the gas industry accounts for \$385 billion in direct domestic economic activity. He and others argue that shale gas production will provide global economic stability until renewables can take hold as the primary source of energy in the march toward mitigating global warming. In the United States, the gas industry provides nearly 3 million jobs, a number that will only rise with the development of shale gas extraction (Engelder, 2011). In a national economy with record unemployment rates, this cannot be more valuable; in fact, some states – Texas and Pennsylvania among them – have specifically pursued shale gas as a “revenue source that might boost sagging economies” (Schmidt, 2011). Not only is shale gas great for the national economy, but it is also great for the personal economy of those lucky enough to own mineral rights to their property: leases to gas companies sell for prices ranging from hundreds to tens of thousands of dollars per acre, in addition to 18% or more in royalties (Schmidt, 2011).

Shale gas can be such a boon to the economy because it is so abundant, another point not forgotten by proponents. Annual production volume grew from 0.2 Tcf in 1998 to 4.9 tcf in 2010, with a threefold increase expected in the next decade (Gregory et al., 2011). By 2030, it is estimated that production rates will near 30 Bcf per day, cornering 24% of total domestic gas production. According to Engelder (2011), estimates of total recoverable gas in the U.S. is on the order of 42 Tcm (1,483 Tcf), a number near that of the total conventional gas discovered in the past 150 years in the U.S. alone. With total recoverable gas estimates equivalent to roughly 65 times the current annual rate of domestic consumption, it is clear why many look to shale gas as a “bridge fuel” between conventional hydrocarbons and renewables (Engelder, 2011). In fact, according to the EIA, “[s]hale gas offsets declines in other U.S. supply to meet consumption growth and lower import needs”

(2011c); as shown in Figure 3, shale gas – at 14% of the natural gas market in 2009 – is projected to encompass almost half the market by 2035 (EIA, 2011c).

Few will disagree with these points – the economics figures are cold, hard facts, and the resource estimates are generally agreed upon and come from reliable sources such as the EIA. However, the benefit most proclaimed by proponents has gotten some controversy – that shale gas is an environmentally cleaner fuel than coal due to fewer by-products and a smaller carbon footprint (Cathles et al., 2012a; 2012b; Gregory et al., 2011; Engelder, 2011). Natural gas “provides twice the energy per unit of weight with half the carbon footprint during combustion,” giving it a greenhouse gas (GHG) footprint “that is half and perhaps a third that of coal” (Cathles et al., 2012a). Gregory et al. (2011) echoes this: “[N]atural gas combustion yields lower emissions of greenhouse gases and other pollutants relative to coal combustion for equivalent amounts of power generation”; so to does

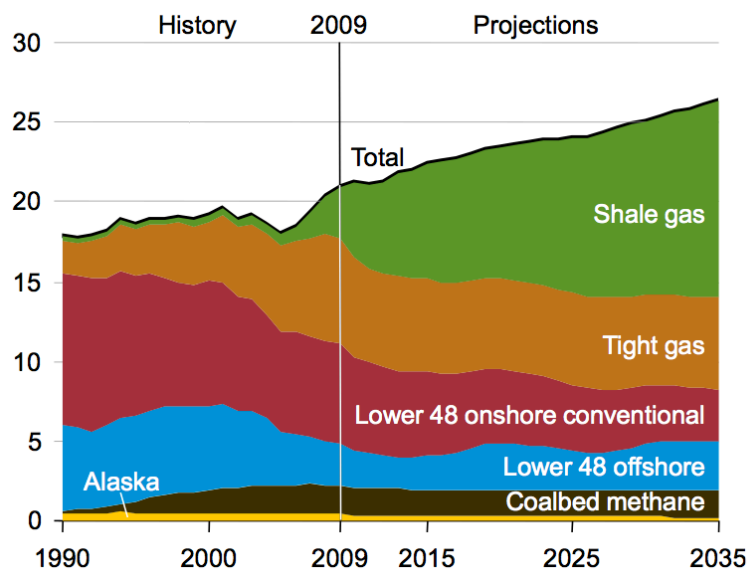


Figure 3: Natural gas production by source in trillion cubic feet, 1990-2035 (EIA, 2011c).

Engelder (2011): “Replacing coal with natural gas in power plants...reduces the plants’ greenhouse emissions by up to 50%.” In an ongoing literature debate between them and fellow researchers at Cornell to be examined in depth in the following section, Cathles et al. (2012b) go so far as to state that substituting natural gas for coal would reduce global warming by 40% of that which would be

attained by immediately transitioning to renewables – and this is without considering carbon capture and sequestration, which would produce further reductions. Are these figures accurate? On what assumptions are these data obtained? Engelder (2011) concludes, “The gains in employment, economics and national security, combined with the potential to reduce global GHG emissions if natural gas is managed properly, make a

compelling case” – but what if natural gas is *not* managed properly? “Shale gas clearly has its benefits,” Schmidt (2011) concludes – but how do those benefits stack up against the risks? The following sections of this paper will focus on assessing these questions and additional concerns.

4. ATMOSPHERIC CONCERNS

As shale gas reservoirs are exploited for the natural gas within, it is a reasonable concern that some of that gas – composed largely of methane – will escape into the atmosphere. But how much methane leaks from the average well, and what potential effect, if any, do methane emissions from shale gas production have on climate change and human health?

4.1 Accelerated climate change

The position that fugitive methane could accelerate climate change is perhaps one of the greatest points of contention regarding shale gas production in the scientific community. This is mainly due to the debate going on between two independent research teams at Cornell University: Robert Howarth et al. and Lawrence Cathles et al. While Cathles et al. hold the majority opinion that emissions are low and that the overall contribution to climate change is less than conventional hydrocarbons (Cathles et al., 2012a; 2012b), Howarth et al. conclude quite the opposite, that methane leakage is high enough and methane is a potent enough GHG to make shale gas production a less viable source of hydrocarbons than conventional sources (Howarth et al., 2011; 2012). What data, usage assumptions, and timescale concerns each team considers make all the difference – but who makes the more legitimate argument? Let us weigh the arguments.

4.1.1 Disagreement over fugitive emission rates of methane

Howarth et al. (2011) estimate that 1.9% of the total lifetime production of shale gas wells is emitted in the form of methane during well completion (1.6% during flowback, 0.33% during drill out). This compares to a fugitive methane emission rate of 0.01% during the well completion of a conventional gas well, as there are no flow-back and no drill out phases – as estimate three orders of magnitude less than for shale gas. Howarth et al. (2011) also estimate fugitive methane emissions rates of 0.3-1.9% for the routine venting and equipment leaks at well sites, 0-0.26% during liquid unloading, 0-0.19% during gas

processing, and 1.4-3.6% during transport, storage, and distribution. Ultimately, Howarth et al. (2011) estimate a net methane loss of 3.6-7.9% of the total production of an average shale gas well during its lifetime; this estimate range is “at least 30% more and perhaps more than twice as great” as the fugitive methane emissions for conventional gas (1.7-6%).

But how reasonable is this estimate? Cathles et al. (2012a) make the claim that Howarth et al.’s (2011) analysis relies heavily on data not representative of modern techniques² and from non-peer-reviewed literature. Perhaps the most egregious example, as emphasized by Cathles et al. (2012a), is that the bulk of Howarth et al.’s (2011) emissions data are not from well-documented sources, with “many values based on PowerPoint slides from EPA-sponsored workshops.” This and any reliance on non-peer-reviewed data is a serious limitation needing resolution with further study. Hultman et al. (2011) commented on this data being the basis for emissions figures, saying

“The numbers are derived from non-peer-reviewed presentations at EPA workshops that do not document their sources. It is moreover possible that, since the workshops that designed to identify sources of potential GHG reduction, there might have been incentives to present inflated numbers.”

However, forgetting the limitations of using data from such a source, Cathles et al. (2012a) find problems with the data itself:

1. Howarth et al. (2011) assume that the initial production values cited in their references can be used as an estimate of the daily methane loss estimates; Cathles et al. (2012a) argue that this assumption is not compatible with the physics of gas production, the economic incentives of gas production, and the shale gas early production data found in their references. They explain that initial production is the period of highest flow, and flowback occurs when there is still a substantial amount of water in the well; therefore, “flowback gas recoveries cannot exceed initial production recoveries,” but this is the implication made by Howarth et al. (2011). This implication does not make sense, considering that gas can only flow optimally when there can be a connected pathway of gas up the well, i.e. when the wellbore is *not* filled with water (Cathles et al., 2012a).

² For example, Howarth et al. (2011) estimate pipeline leakage to be between 2.5-10%, but the higher value is from Soviet-era data reflecting poorly maintained pipelines in Russia.

Thus, Howarth et al.'s (2011) estimates are askew due to the faulty assumption that initial production values and daily methane loss estimates are equivalent.

2. Howarth et al.'s (2011) references only discuss methane losses during well completion in the context of tight gas sands, and this discussion is in the context of how up to 99% of these losses can be captured for sale using currently-used technologies (Cathles et al., 2012a). These references explicate the capture and sale of completion gases, a practice reportedly done for several years as an economic incentive over venting or flaring. Cathles et al. (2012a) point out that only one source³ of Howarth et al.'s (2011) provides an actual measurement of captured and lost emissions – a loss rate of 0.1% of total productions. As an example, according to this source, the Williams Corp. shows that >90% of the flowback gas is captured, with some of the remainder flared. Cathles et al. (2012a) conclude that “[i]f this were generally the case, Howarth et al.'s (2011) 1.9% leakage would be reduced to 0.2%.”
3. Cathles et al. (2012a) take issue with Howarth et al.'s (2011) assumption that 10 million cubic feet of gas is vented during drill out; their source makes no such claim, and Cathles et al. (2012a) argue that, in fact, “gas production is rare during drill out and if significant gas were produced during drill out it would not be emitted into the atmosphere for economic and safety reasons.” For example, they show that if Howarth et al.'s (2011) 3.2% estimate were true, then over \$1,000,000 worth of gas would be lost if vented into the atmosphere over a periods of ~10 days, which would be absurd from any company's point of view (Cathles et al., 2012a).
4. The aforementioned issues taken by Cathles et al. (2012a) all deal with well completion emissions, they also take issue with Howarth et al.'s (2011) analysis of methane leakage from the well site to the customer. As these losses rely on a variety of sources, it is hard to measure them accurately. That said, a few studies have attempted to estimate such losses, with the most recent, an EPA study (2011a),⁴ estimated a ~2.2% loss between

³ An EPA workshop in 2007 entitled “Reducing methane emissions during completion operations”

⁴ Though the EPA is not without agenda, it is heavily relied upon by both Howarth et al. (2011; 2012) and Cathles et al. (2012a; 2012b), specifically this particular report, the *2011 U.S. Greenhouse Gas Inventory Report*, because of its wide breadth of sources. According to the EPA website, this annual report “tracks the national trend in greenhouse gas emissions and removals back to 1990. The report contains total U.S.

the source and the customer. This figure breaks down to 1.3% loss at the well site, 0.73% during transmission, storage, and distribution, and 0.17% during processing (Cathles et al., 2012a). However, Howarth et al. (2011) assert a 1.4-3.6% loss during transmission, storage, and distribution (a self-described “conservative” claim), a whole 2-5 times higher than the EPA’s most recent estimate of 0.73% (Cathles et al., 2012a).

Not to be corrected, Howarth et al. (2012) responded to the criticisms from Cathles et al. (2012a), stating that they “disagree with each point ... [our] methane emission estimates during well completion and flowback are quite consistent with both those of EPA”:

1. Howarth et al. (2012) refute the claim gas venting during flowback is low. They admit that in the early stages of flowback, liquids can restrict gas flow, but gas is freely vented in the latter stages. ... Initial flowback is 100% liquid, but this quickly becomes a two-phase flow of liquid and gas as backpressure within the fractures declines. ... The gas produced is not in solution, but rather is free-flowing with the liquid in this frothy mix. (Howarth et al., 2012)

They quote EPA (2011b) to back up their argument, saying “The high rate backflow [includes] intermittent slugs of water and sand along with free gas ... [T]he free gas vents to the atmosphere.” They further contest Cathles et al.’s claim that they used initial production rates, thereby over-estimating flowback venting, stating that their estimates of such emissions for all but the Haynesville basin were based on “industry-reported volumes of gas captured,” *not* on initial production rates (2012). However, they note that they did use initial production rates, but only in application to the “latter portion of flowback duration as an estimate of venting,” which is “commonly accepted,” according to Howarth et al. (2012).

2. Regarding Cathles et al.’s (2012a) claim that Howarth et al. (2011) assume incorrectly that the data on captured gas in their references is normally vented to the atmosphere, Howarth et al. (2012) admit that they used their references’ data on captured gas as a

emissions by source, economic sector and greenhouse gas.” To calculate these emissions totals, the EPA uses “national energy data, data on national agricultural activities, and other national statistics to provide a comprehensive accounting of total [domestic] GHG emissions ... [including] data from individual facilities and suppliers of certain fossil fuels and industrial gases.”

substitute for vented emissions, but that they did so correctly, “similar to such interpretation by EPA.” They explain that there is no data on venting rates, as industry neither measures nor estimates how much gas is vented during flowback, so they assume that “the rate of gas flow is the same during flowback, whether vented or captured” (2012).

3. Regarding Cathles et al.’s (2012a) assertion that capturing or flaring vented gas during flowback is a safety and economic no-brainer to gas companies, Howarth et al. (2012) hold that the reality just is not so. They quote the latest EPA estimates as showing that “85% of flowback gas from unconventional wells is vented and less than 15% flared or captured.”⁵ Howarth et al. (2012) do not approve of this venting, but justify industry’s

practice of it by explaining that it is not as unsafe as Cathles et al. (2012a) make it out to be in terms of a fire/explosion hazard because the density of methane is only 58% that of air; thus, any vented methane would have a high buoyancy, as can be seen in Figure 4 at a well in Susquehanna County, PA. It is important to emphasize that the video from which this still photo was taken is not used by Howarth et al. (2012) to “infer any information on the rate of venting, but simply to illustrate that venting

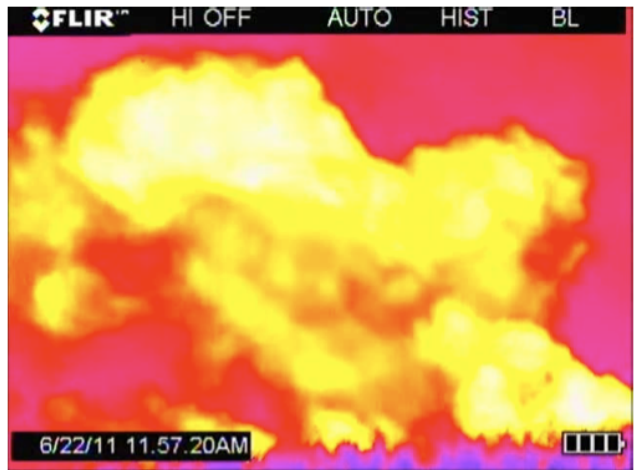


Figure 4: Methane-tuned FLIR image of venting of natural gas into the atmosphere at the time of well completion and flowback in Susquehanna County, PA. For scale, the magenta ridge at the bottom is composed of the tops of pines (Howarth et al., 2012).

occurred in the summer of 2011 in Pennsylvania and that the gas rose rapidly into the atmosphere.” In fact, they show that Cathles et al.’s (2012a) claim that venting is illegal in Pennsylvania is misleading: PA § 78.73, *General provision for well construction and operation*, states that “excess gas encountered during drilling, completion or stimulation shall be flared, captured, or diverted away from the drilling rig in a manner

⁵ Unfortunately, other agencies like the EIA only report vented and flared gas together and do not distinguish between the two, and industry “does not usually measure or estimate the gas that is vented during flowback,” according to Howarth et al. (2012).

than does not create a hazard to the public health or safety,” with “diverted away” being the exceptional phrase.

Concerning the economic incentive for industry to capture and sell vented gas claimed by Cathles et al. (2012a), Howarth et al. (2012) show that industry is more incentivized to use funds for more profitable projects. This is because the current value⁶ of natural gas barely allows gas companies to pay for the process of capturing vented gas, i.e. they would actually lose money. This is corroborated by EPA data, which projects that this would be the case for the next two decades based on current price forecasts (EPA 2011c).

4. Finally, Howarth et al. (2012) address Cathles et al.’s (2012a) criticism of their high estimate of methane emissions during the storage, transmission, and distribution phase. Cathles et al.’s (2012a) main disagreement came from the fact that Howarth et al.’s (2011) estimate of 1.4-3.6% is roughly 2-5 times greater than the EPA’s most recent estimate of 0.73%. However, Howarth et al. (2012) show that that EPA estimate is from a 1996 study, and thus severely outdated.⁷ Howarth et al. (2012) take issue with this EPA estimate not only for its obsolescence, but also for its basis: the data in the 1996 study in question were obtained from the analysis of emissions from model facilities instead of random sampling or actual industry practices. The EPA has updated several emission factors for natural gas systems since 2010, and is currently considering updating this particular assumption. Howarth et al. (2012) ultimately attribute their high overall estimates on this one sector.

Additionally, Howarth et al. (2012) further compare their estimates against the newest estimates of the EPA, related studies, and Cathles et al. (2012a). By comparison, they show that Cathles et al. (2012a) have the lowest estimate range for shale gas fugitive emissions of any study or report in consideration. (See Table 1 for a breakdown.) But while Cathles et al. (2012a) have the lowest estimate range, it is clear that the other studies also conclude lower emissions than Howarth et al. (2011), albeit not as low as Cathles et al. (2012a). But what accounts for this disparity?

⁶ This is according to EPA data, which uses the price of gas as of 2008: \$6.50 per thousand cubic feet.

⁷ A bit of a hypocrisy, considering that Howarth et al. (2011) used no-longer relevant Soviet-era data in their estimation of pipeline leakage as mentioned earlier

Table 1: Comparison of published estimates for full life-cycle methane emissions from conventional gas and shale gas (adapted from Howarth et al., 2012 – studies without shale gas estimates excluded and percent difference from EPA (2011a) added)

Study (listed chronologically)	Conventional gas (gC MJ ⁻¹)	Difference from EPA (2011a)	Shale gas (gC MJ ⁻¹)	Difference from EPA (2011a)
<i>Howarth et al. (2011)</i>	0.26-0.96	-32% to +153%	0.55-1.2	-12% to +100%
<i>EPA (2011a)</i>	0.38	--	0.60	--
<i>Jiang et al. (2011)</i>	N/A	--	0.30	-50%
<i>Hultman et al. (2011)</i>	0.35	-8%	0.57	-5%
<i>Skone et al. (2011)</i>	0.27	-29%	0.37	-38%
<i>Burnham et al. (2011)</i>	0.39	+3%	0.29	-52%
<i>Cathles et al. (2012a)</i>	0.14-0.36	-63% to -5%	0.14-0.36	-77% to -40%

First, these studies (Jiang et al., 2011; Hultman et al., 2011; Skone et al., 2011; Burnham et al., 2011) all only consider unconventional gas in the context of electricity. As Howarth et al. (2012) notes, only 30% of natural gas is used to generate electricity. “[N]one of the electricity-based studies provide an adequate basis” for evaluation of shale gas GHG emissions in other uses, says Howarth et al. (2012). But the main reason for the disparate estimates lies in the choice of data. Hultman et al. (2011) come the closest to Howarth et al.’s (2011) conclusion; in fact, Howarth et al. frequently how similar their sub-estimates for several categories of emissions being considered. However, Hultman et al. (2011) choose lower GWPs, a “major factor in this calculation”: 72 and 25 times that of CO₂ over a 20- and 100-year horizon, respectively, as compared to Howarth et al.’s (2011) respective figures of 105 and 33. Hultman et al. (2011) criticize Howarth et al.’s (2011) figures as they are merely the medians as determined by Shindell et al. (2009), and are not considered with their respective error. Jiang et al. (2011) not only use similar GWPs to Hultman et al. (2011), but they also assume a very large figure for the lifetime of an average well – 25 years. Moreover, this parameter is given in a table of 15 other various parameters, and it is the only figure in which the maximum of the given range – in this case, 5 to 25 years – is used in calculations as opposed to the median. The result of such an overestimation is an underestimation of the emissions per unit of energy available from gas production. As the oldest high-volume shale gas fracking wells are only a decade old and production falls off more rapidly than for conventional wells, such a high value is highly uncertain (Howarth et

al., 2012). Jiang et al. (2011) also considers only the 100-year horizon. Burnham et al. (2011) also only considers the 100-year horizon. Burnham et al. (2011) are also the only study of the group that concludes shale gas to have fewer methane emissions than conventional gas: they estimate that both conventional and shale gas have the same gas leakage values for all parameters except in the case of “well completions and workovers” and “liquid unloadings,” in which they estimate conventional gas to have a mean value of 0.003% and 1.20% total production, respectively, and shale gas 0.46% and none, respectively. Almost all their key sources are from the EPA, and they are those that Howarth et al. (2012) criticized for using outdated data from 1996 to estimate methane emissions during the storage, transmission, and distribution phase.

With all of the uncertainty regarding estimates in the aforementioned studies, Howarth et al. (2011; 2012) and Cathles et al. (2012a; 2012b) included, it is impossible to make an objective statement with regard to who is correct. However, for the sake of considering the implications of Howarth et al.'s claims as they are the most serious, henceforth I shall assume that Howarth et al. have sufficiently defended their interpretation of the relevant data, ultimately implying a net methane loss of 3.6-7.9% of the total production of an average shale gas well during its lifetime and 1.7-6% of the total production of an average conventional gas well during its lifetime. What consequences does this have for climate change when the GHG footprint of shale gas is weighed against that of both conventional other sources of hydrocarbons?

4.1.2 Disagreement over the GHG footprint of shale gas

Considering the contribution of their estimates of methane emissions from shale and conventional gas, Howarth et al. (2011) attempt to establish GHG footprints for each. To determine these footprints, they use “recently modeled values for the global warming potential (GWP) of methane compared to CO₂: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al., 2009). They note that they chose these data over those in the fourth assessment report of the Intergovernmental Panel on Climate Change (IPCC) because they “better account for the interaction of methane with aerosols.” Howarth et al. (2011) believe heavily in the importance of the 20-year horizon over the 100-year horizon, despite the fact that it is the

latter is more commonly considered. This is because even though methane has an atmospheric residence time ten times shorter than that of CO₂, it is far more potent; thus, they conclude that “the 20-year horizon is critical, given the need to reduce global warming in coming decades” (2011). On this shorter time scale, Howarth et al. (2011) find that methane contributes 1.4 to 3 times more to the GHG footprint of shale gas than does direct CO₂ emission.

When weighed against sources of conventional hydrocarbons, Howarth et al. (2011) found that the GHG footprint for shale gas is:

- (for conventional gas) 22% to 43% larger on the 20-year horizon and 14% to 19% larger on the 100-year horizon;
- (for coal) 20% to 100% larger on the 20-year horizon and comparable on the 100-year horizon (“the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions”)⁸;
- (for oil) 50% to 250% larger on the 20-year horizon and 35% larger on the 100-year horizon.

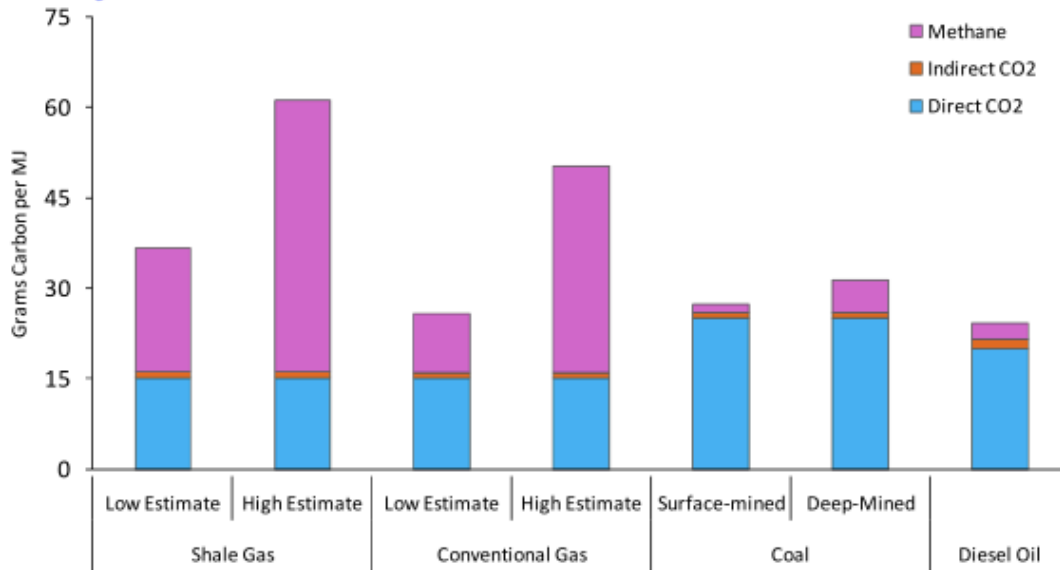
Howarth et al. (2011) note that their analysis does not consider the efficiency of final use, admitting that “[i]f fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation”; they also note that when used as heating and transportation fuel, there is no evidence that shale gas efficiencies are greater than diesel oil. These data are graphically represented in Figure 5.⁹

Based on these conclusions – namely, that the GHG footprint of shale gas is so large – Howarth et al. (2011) posit that the use of shale gas as a “bridging fuel” makes little sense if its intention is to reduce global warming. They note that “substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming” (2011). The 100-year horizon and the use of out-of-date GWPs for methane are key to this conclusion. (Howarth et al. make a clear and repeated point that the uncertainty in the magnitude of fugitive emissions is large. They urge greater study of these emissions.)

⁸ Estimate is “when expressed per quantity of energy available during combustion” (Howarth et al., 2011)

⁹ “Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure” (Howarth et al., 2011).

A. 20-year time horizon



B. 100-year time horizon

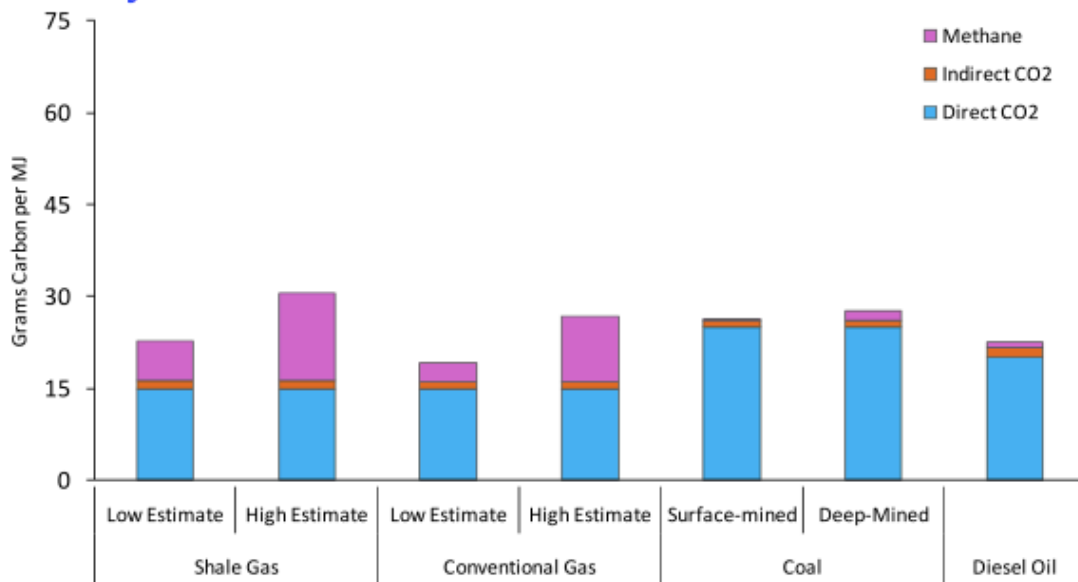


Figure 5: Comparison of GHG emissions from various hydrocarbon resources. “Estimates include direct emissions of CO₂ during combustion (blue bars), indirect emissions of CO₂ necessary to develop and use the energy source (red bars), and fugitive emissions of methane, converted to equivalent value of CO₂ as described in the text (pink bars). Emissions are normalized to the quantity of energy released at the time of combustion.” (Howarth et al., 2011).

It is with this conclusion that Cathles et al. (2012a) have their second and perhaps greatest criticism. They argue that the literature justification offered by Howarth et al. (2011) to support the adoption of a 20-year horizon for the GWP of methane was originally and solely in the context of increasing incentives for reducing methane emissions from tropical deforestation and biomass burning; a 100-year horizon would not discourage such practices (Nisbet et al., 2000; Cathles et al., 2012a). Cathles et al. (2012a) argue that focusing on the 20-year horizon hides the fact that the lifetime of CO₂ in the atmosphere is much longer than that of methane, a critical point in the context of discussing swapping gas for coal. They quote Pierrehumbert (2011) to summarize their opinion, saying

“Over the long term, CO₂ accumulates in the atmosphere, like mercury in the body of a fish, whereas methane does not. For this reason, it is the CO₂ emissions, and the CO₂ emissions alone, that determine the climate that humanity will need to live with.”

Cathles et al., (2012a) admit that an argument could be made for the 20-year horizon if there were a legitimate concern over “triggering an irreversible tipping point such as glacial meltdown,” but state that this would only be the case if on the 20-year horizon, the substitution of gas for coal increased the GHG impact, as Howarth et al. (2011) argued; however, as Cathles et al. (2012a) previously argued, Howarth et al.’s (2011) estimates of fugitive emissions were too high. According to Cathles et al.’s (2012a) estimates, shown below, the “substitution of gas for coal minimizes the tipping point risk as well,” even on the 20-year horizon.¹⁰

Howarth et al.’s (2011) choice to compare GHG footprints on the basis of heat content is considered to be irrelevant by Cathles et al., (2012a); when being considered as a bridge fuel, Cathles et al. argue that the only appropriate basis of comparison is instead electricity generation, as coal is almost entirely utilized for this end use. Its substitution with gas will thus by necessity be in generating electricity, as “the ‘bridge’ is from coal-generated

¹⁰ Cathles et al. (2012a) cite Hayhoe et al. (2002), who forwent what they call the “arbitrariness” of GWPs to instead consider the warming effects of “decreasing SO₂ and black carbon emissions as coal burning is reduced as well as the warming effects of CO₂ and CH₄ emissions.” They then calculate the greenhouse impact of different substitution scenarios on the 100-year horizon using a “coupled atmosphere-ocean energy balance climate model”; per this model, the substitution of gas for coal does not reduce global warming on the 20-year horizon, but does on the 100-year horizon.

electricity to a low-carbon future source of electricity such as renewables or nuclear” (Cathles et al., 2012a). They even note that Howarth et al. (2011) acknowledges that, if the final use is considered, “the ability to increase efficiency is probably greater for natural gas than for coal (Hayhoe et al. 2002), and this suggests an additional penalty for using coal over natural gas for the generation of electricity not included in our analysis.” This is only acknowledged in their electronic supplemental material and not in their main analysis.

Compensating for Howarth et al.’s (2011) lack of consideration of end use, Cathles et al. (2012a) composed the graph in Figure 6 to depict a “more representative comparison of the likely impact on GHG emissions when natural gas replaces coal in older coal-burning electric power plants.” Their analysis assumes 60% efficiency¹¹ for the generation of electricity by natural gas, 30% efficiency the generation of electricity by coal in older plants, and a total methane leakage rate of 2.2%. They determined that

“[f]or leakage rates less than 2%, the impact of natural gas approaches one third that of coal, and methane leakage (top green bar) is an insignificant part of the greenhouse forcing compared to the CO₂ released during combustion (bottom blue part of bar). For the 100y GWP of 33, gas exceeds the global warming impact of deep coal only when its leakage rate exceeds 18.2% of production, and exceeds the global warming impact of surface coal only when its leakage exceeds 17.1% of production. These natural gas leakage rates are well beyond any known estimates. If the fuels are compared just on the basis of heat (i.e. disregarding efficiency of use), gas has a lower greenhouse impact than coal if the leakage is <5.5% for a 100 year GWP, and if the leakage is <2% for a 20 year GWP. ... Although no plant of this kind has yet been constructed, the 4th column in the gas category of [Figure 6] shows that the greenhouse impact of a gas plant with 50% conversion efficiency would have about half the GHG impact of this high-end coal plant.” (Cathles et al., 2012a)

In their response to Cathles et al.’s (2012a) criticisms, Howarth et al. (2012) also address the issues taken regarding the GWP of methane and the consideration (or rather, the lack thereof) of electricity as the sole end use.

¹¹ Cathles et al. (2012a) add, “Sixty percent conversion efficiency is not the limit for gas. Combined heat and power (CHP) generation can utilize 90% of the chemical energy in gas.”

First, Howarth et al. (2012) defend their stance that controlling methane emissions immediately, together with controlling other sources of carbon emission, is critical to avoid “tipping points” in the Earth’s climate system, as supported by Hansen et al. (2007); particularly, “since methane release from permafrost becomes increasingly likely as global temperature exceeds 1.8°C above the baseline average temperature between 1890 and 1910,” as this could create a rapidly accelerating positive feedback loop of increased climate change (Howarth et al., 2012; Hansen et al., 2007). Both Shindell et al. (2011) and a joint study from the United Nations Environment Programme (UNEP) and the World Meteorological Association (WMO) conclude that this 1.8°C threshold could be reached in as soon as 30 years; that is, unless immediate action is taken to “reduce the emissions of

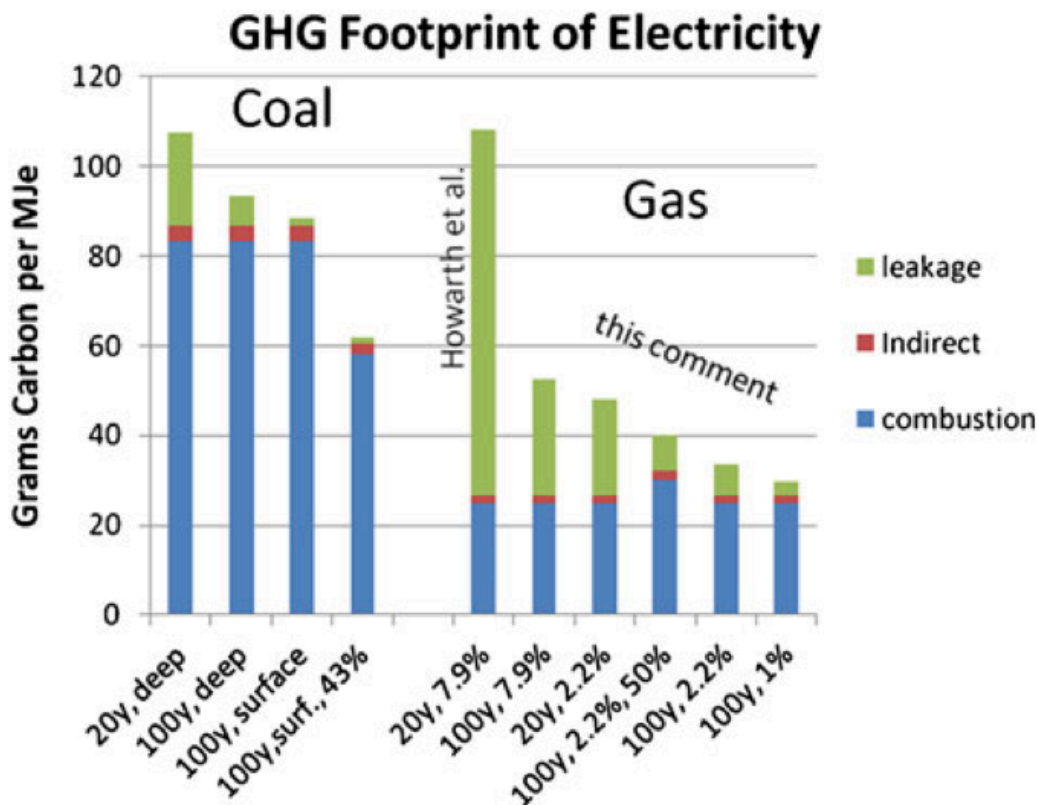


Figure 6: “Comparison of the greenhouse impact of burning natural gas to coal when the fuels are used to produce electricity, expressed as the grams of GHG-equivalent CO2 carbon per megajoule of electricity generated. The conversion efficiency to electricity of coal and gas are assumed to be 30 and 60% respectively in all columns except the 4th and 8th columns, which compare a very efficient coal plant to a less efficient gas plant. As in Howarth et al. (2011) we use 20 and 100 year GWP factors of 105 and 33 g of GHG- equivalent CO2 per gram of methane released, and assume deep and shallow coal mining releases 8.4 m3 and 2.3 m3 methane per ton, respectively. Indicated below each column are the GWP factors, the percent methane leakage (1, 2.2 and 7.9%), whether the coal burned is from deep or shallow mines, and where different from 60%, the gas conversions efficiency used in the calculation” (Cathles et al., 2012a).

methane and other short-lived greenhouse gases now” (Howarth et al., 2012; UNEP/WMO, 2011). Additionally, the lower bound for the “danger zone for a temperature increase leading to climate tipping points” is 1.5°C – an increase that will occur in the next 18 years, if, again, “emissions of methane and other short-lived radiatively active substances such as black carbon are not better controlled, beginning immediately” (Shindell et al., 2011; UNEP/WMO, 2011; Howarth et al., 2012).¹² As mentioned earlier, these studies claim that their data “account for the interaction of methane with aerosols” better than IPCC (2007), but it is still worth considering that IPCC (2007) estimated a global temperature rise of 1.8-4.0°C by 2090 – a mean increase of about 0.3°C per decade, which is approximately half the rate extrapolated from Shindell et al. (2011) and UNEP/WMO’s (2011) assertion that a 1.8°C rise could be reached in 30 years.

Howarth et al. (2012) note that, while their values of 105 and 33 for the 20- and 100-year horizons, respectively, are based on the “latest information on methane interactions with other radiatively active materials in the atmosphere,” (Shindell et al., 2009), EPA (2011a) uses a 100-year GWP value of 21 based on IPCC (1995), and Cathles et al. (2012a) uses a value of 25 based on IPCC (2007) (Howarth et al., 2012). The latter, Howarth et al. (2012) claim, underestimates methane’s GWP by 33% when compared to Shindell et al.’s (2009) more recent value of 33. This is a significant difference, as, according to data from EPA (2011a), “methane contributes 19% of the entire GHG inventory of the US at the century time scale and 44% at the 20-year scale, including all gases and all human activities” (Howarth et al., 2012).

Second, Howarth et al. (2012) defend their focus on GHG emissions normalized to heat content. While only 30% of natural gas in the United States is used for electricity generation, the majority of natural gas is used for heating purposes; globally, 47% of all energy is allocated to heating, and natural gas provides over half of that demand in

¹² Indirect support for Howarth et al.’s (2011) “tipping point” argument has recently been voiced from scientists at the “Planet Under Pressure” conference in London. Will Steffen, the executive director of the Australian National University’s climate change institute declared, “This is the critical decade. If we don’t get the curves turned around this decade, we will cross those lines.” He pointed to such ticking time bombs as the drying of the Amazon rainforest and the thawing of the Siberian permafrost, which alone holds about 1.6 trillion tonnes of carbon – twice the amount in the atmosphere today. “And the northern high latitudes are experiencing the most severe temperature change of any part of the planet,” he said (*Scientific American*, 2012).

developed countries (Howarth et al., 2012). Howarth et al. (2012) reiterate the point from their 2011 comment that “generating electricity from natural gas has some efficiency gains over using coal,” but emphasize that there is no such advantage for natural gas over other fossil fuels when considering heat as an end use. They also add that as natural gas is also being considered in an energy future as a transportation fuel, its implications should also be researched in this context. Preliminary research from Howarth et al.’s (2012) study concludes that shale gas has a larger GHG footprint than diesel oil. Further worsening this footprint is the fact that long-distance trucks would likely use liquefied natural gas, the GHG emissions from which are much higher than for non-liquefied gas (Howarth et al., 2012). This runs contrary to a bill introduced in Congress in 2011, the “Natural Gas Act” (H.R.1380), which would provide tax subsidies to encourage long-distance trucks to switch from diesel to natural gas.

4.1.3 Conclusion?

After assessing every argument, counter-argument, and defense in the literature war between Howarth et al. and Cathles et al., who makes the stronger case? Whose conclusions are more legitimate? Is shale gas actually worse than coal in terms of contributions to GHG emissions and GWP, or is it an appropriate bridge fuel, better than coal in every way? It is hard to say – it ultimately depends on whether or not one trusts Howarth et al.’s (2011) assumptions in obtaining fugitive emissions estimates, the notion that the 20-year horizon is a significant consideration, and whether or not heat generation should be considered when speaking in terms of “bridge fuels.” I believe that Howarth et al. (2012) make a strong defense of their original comment (2011) against the criticisms of (Cathles et al., 2012a). Cathles et al.’s (2012a) conclusions are accurate ones based on their assumptions and data, but, in my opinion, Howarth et al. (2012) showed why Cathles et al.’s assumptions do not sufficiently consider every venue of contribution to global warming methane can have and why some of their data is not the best data available for evaluating emissions rates and GWP; however, because the latter criticism can rightfully be made against Howarth et al.’s (2011) reliance on data from EPA workshop PowerPoint slides, their data needs to be corroborated by peer-reviewed research. At the very least, further research should be done to obtain better data to produce more accurate estimates and projections. Howarth et al.

(2012) conclude, “We stand by our conclusions in Howarth et al. (2011) and see nothing in Cathles et al. and other reports since April 2011 that would fundamentally change our analyses,” and, at this time, neither do I.

4.2 Human health concerns

On a more local scale, emissions from shale gas production could possibly be cause for concern with regard to the health of local residents. For instance, condensate tanks, which collect a semi-liquid condensate (composed of hydrocarbons that change from the gaseous to liquid phase during the production process), emit several noxious compounds. Among them is carbon disulfide, or CS₂, which causes cardiovascular, neurologic, and hepatic effects with chronic high exposure (Schmidt, 2011). Additionally, these tanks emit benzene (a known human carcinogen), toluene, ethylbenzene, and xylene (as a group, called BTEX), the vapors of which are heavier than air and thus accumulate in low-lying areas (Colborn et al., 2011). Benzene, xylenes, and naphthalene were all detected at elevated levels in DISH, Texas, a small town amidst a gas production site on the Barnett Shale, by Wolf Eagle Environmental of Flower Mound, Texas; additionally, the Washington DC-based environmental group Earthworks “detected carbon disulfide along with dimethyl disulfide and methyl ethyl disulfide—which are both skin, eye, and respiratory irritants—at levels above air quality standards set by the Texas Commission on Environmental Quality” (Schmidt, 2011). These two groups were prompted to sample the air quality in DISH after several complaints by its residents of strange odors and a spike in illnesses in the community.

In other gas-producing communities, residents living near production facilities complain of “headaches, diarrhea, nosebleeds, dizziness, blackouts, muscle spasms, and other problems,” but detailed studies regarding such adverse health effects are few, and those that do exist have yielded conflicting results (Schmidt, 2011). In fact, according to a professor of public health at the University of Pittsburgh, “published epidemiologic studies relating shale gas production to health are virtually nonexistent” (Schmidt, 2011). Thus, it is hard to scientifically support anecdotal claims of adverse health effects from shale gas development. One site-specific study – the only one of its kind – commissioned by Garfield County, Colorado, and conducted by researchers from the Colorado School of Public Health

set out to investigate the potential health effects of a proposed 200-well gas operation in Battlement Mesa. The study concluded that the community's residents – many of whom live within 600 feet of the proposed wells – could experience “chemical exposures, accidents resulting from industry operations, and psychological impacts such as depression, anxiety, and stress” (Schmidt, 2011).

The EPA regulates major sources of air pollution via the Clean Air Act, in which “major” is defined as emitting 10-250 tons of pollutants per year, depending on the pollutant – but its authority over air emissions from shale gas development is limited (Schmidt, 2011). Gas-producing operations as a whole have the potential to fall into this range, but “confirming that requires complex, site-specific investigations that states tend to avoid,” and individual emissions units – drill rigs, condensate tanks, compressors, etc. – rarely generate enough pollution on their own to be considered major sources (Schmidt, 2011). This allows gas companies neither to report their emissions nor to tell state regulators that such units even exist, but together these units emit substantial amounts of air pollution. For example, in a permit review, the Pennsylvania Department of Environmental Protection lists potential emissions of a compressor operating in German Township amounting to 73.5 tons per year of nitrogen oxides (NO_x) and 19.36 tons per year of volatile organic compounds (VOCs), including BTEX, other hydrocarbons, and fugitive methane – well over the 10-ton threshold established by the EPA (Schmidt, 2011).

A concern with NO_x and VOCs is that, when mixed, they produce ground-level ozone, which can cause significant respiratory and cardiac problems. One particular molecule of ground-level ozone is highly reactive and can “burn the deep alveolar tissue in the lungs, causing it to age prematurely. Chronic exposure can lead to asthma and chronic obstructive pulmonary disease (COPD)” (Colborn et al., 2011). In Sublette County, Wyoming, where there is extensive gas production, winter ozone levels “routinely spike over the EPA's 8-hour ozone standard of 75 ppb,” exceeding this threshold by 13 times from February 14 to March 15 in 2011 (Schmidt, 2011). When ozone combines with particulate matter less than 2.5 μm, it produces smog, which “has been demonstrated to be harmful to humans as measured by emergency room admissions during periods of elevation” (Colborn et al., 2011). During these spikes, the ozone levels in Sublette County has been known to peak at

just under 1000 ppb, rendering it almost eight times worse than the average ozone level in Los Angeles in 2010 (123 ppb) and about twelve times worse than Denver's 2010 average (76 ppb) (Schmidt, 2011; South Coast Air Quality Management District (AQMD), 2011; EPA, 2011d).

5. HYDROLOGIC CONCERNS

In addition to the potential for atmospheric emissions to cause distress, there are plenty of hydrologic concerns as well. Shale gas production requires much water, straining resources, and the plethora of chemicals added to that water to produce fracking fluids make for a dangerous cocktail – but just how dangerous are these chemicals, how are they being treated upon disposal, and could methane be a waterborne concern as well?

5.1 Water resources

Drilling both the vertical and horizontal components of a well requires large amounts of water to create a circulating mud that both cools the drillhead and removes drill cuttings, in addition to maintaining downhole hydrostatic pressure (Gregory et al., 2011; Kargbo et al., 2011). Estimates of the amount of water needed for drilling a single well range from 100,000 to 1 million gallons (Gregory et al., 2011). During hydraulic fracturing, even more water is needed: various estimates in the literature exist, including 1.8-4.8 million gallons (Gregory et al., 2011), 2-10 million gallons (Kargbo et al., 2011), and 2-4 million gallons (Schmidt, 2011). As there are large transportation costs associated with trucking in water from great distances, these large volumes of water are typically extracted on-site from nearby streams or pumped from a municipal underground source (Gregory et al., 2011; Kargbo et al., 2011). According to the EPA, 35,000 wells undergo fracking every year in the United States, requiring the amount of water consumed by 5 million people annually (Schmidt, 2011). This demand strains water supplies, especially “under drought conditions, low seasonal flow, [in] locations with already stressed water supplies, or [in] locations with waters that have sensitive aquatic communities that depend on clean, cool waters” (Kargbo et al., 2011). Kargbo et al. (2011) note about 36% of the Delaware River Basin, for example, are headwaters and underlain by the Marcellus Shale, posing a major water resource concern for the 5 million people who inhabit the Delaware River Basin.

5.2 Flowback concerns

All of this water has to go somewhere. In a producing shale gas well, flowback and produced water are the result. Flowback is fracturing water that is returned early in the life of a well, which includes residual fracturing fluid and solid material from the formation. Produced water is any water displaced from the formation; thus, it contains substances found in the formation (DOE, 2009a). As mentioned above, for the first 2 to 3 weeks after fracking, flowback occurs at rates ranging from 3 to 6 barrels per minute (125 to 250 gallons per minute) for a few hours, falling to 29 gallons per minute (1000 barrels per day) within 24 hours, then further dropping over several days to a few hundred barrels per day by the end of the second or third week, eventually falling to a few barrels per day within a few more weeks. The amount of flowback is highly variable and depends on the formation; rates from 5% to 50% have been observed according to King (2011); Schmidt (2011) reports higher rates of flowback, ranging from 30% to 70% of total injected water.

The danger with flowback and produced waters is in their composition: extraction fluids injected into the formation are amended with a host of introduced chemicals, both toxic and nontoxic, at a concentration of about 0.5-2% of the total volume of the fracking fluid (Schmidt, 2011). The added chemicals act to “increase the density and weight of the fluids in order to facilitate boring, to reduce friction, to facilitate the return of drilling detritus to the surface, to shorten drilling time, and to reduce accidents” (Colborn et al., 2011). According to Kargbo et al. (2011), some of these chemicals include

“hydrochloric or muriatic acid, hydroxyethyl cellulose as gel, glutaraldehyde as biocide, petroleum distillate (or diesel) as friction reducer, ammonium bisulfate as oxygen scavenger, 2-hydroxy-1,2,3-propanetricarboxylic acid for iron control, N,n-dimethyl formamide as corrosion inhibitor, ethylene glycol (or 2-butoxyethanol) as scale inhibitor, and methanol-based surfactants. Fluorocarbons, naphthalene, butanol, and formaldehyde have also been reported to be present.”

Both produced and introduced waters come into contact with formation materials, which are commonly enriched in organic compounds, heavy metals and other elements, salts, and radionuclides (Volz, 2011). Thus, wastewaters contain dissolved minerals and organic constituents from the formation, “creating a brine solution that includes high

concentrations of salts, metals, oils, greases, and soluble organic compounds, both volatile and semivolatile” (Gregory et al., 2011). According to the testimony of Dusty Horwitt, JD Senior Counsel to the Environmental Working Group, before the New York City Council Committee on Environmental Protection, the amount of distillates used in a single well could be enough to contaminate 650 million gallons of water – the same amount consumed by New York City residents daily (Horwitt, 2011).

As just mentioned, radionuclides are a potential concern in produced water, especially in the Marcellus Shale. This is not unusual, as Devonian-age shales contain naturally occurring radioactive material (NORM); NORMs that have been concentrated or exposed to the environment as a result of human activity are considered by the EPA to be technologically-enhanced NORM (TENORM), which become concentrated “because of (1) temperature and pressure changes during oil and gas production, (2) ^{226}Ra and ^{228}Ra in produced waters reacting with barium sulfate (BaSO_4) to form a scale in well tubulars and surface equipment, (3) ^{226}Ra and ^{228}Ra occurring in sludge that accumulates in pits and tanks, and (4) NORM occurring as radon (Rn) gas in the natural gas stream” (Kargbo et al., 2011). Brine samples taken from the Marcellus Shale were found to have had elevated gross alpha (α), gross beta (β), and ^{226}Ra ; in fact, 13 samples of wastewater from operations in the Marcellus Shale contained levels of radium-226 (^{226}Ra) up to 267 times the safe disposal limit and thousands of times the safe drinking limit (Kargbo et al., 2011).¹³

The composition and treatment of flowback is largely unregulated. In 2005, an amendment to the Energy Policy Act was passed that eliminated the EPA’s authority to regulate fracking through the Safe Water Drinking Act (*The Nation*, 2011).¹⁴ The result of this amendment is free reign for gas companies to drill essentially when and where they see fit, and – more importantly – to “use and dispose of proprietary fracking fluids without any disclosure or safety requirements” (*The Nation*, 2011). Additionally, gas companies have been granted exclusions and exemptions from several other federal environmental statutes through legislative efforts, including

¹³ Sample analysis was done by New York’s Department of Environmental Conservation (NYDEC) and the New York Department of Health (NYDOH) (Kargbo et al., 2011).

¹⁴ Known as the Halliburton Loophole, the amendment was introduced by then-Vice President Dick Cheney, whose former employer pioneered the fracking process in the 1940s (Cusolito, 2011).

“the Clean Water Act, the Clean Air Act, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, better known as the Superfund Act), the Resource Conservation and Recovery Act (RCRA), the Toxic Release Inventory under the Emergency Planning and Community Right-to-Know Act (EPCRA), and the National Environmental Policy Act (NEPA).” (Colborn et al., 2011)

As a result of so many federal exemptions, drilling is almost entirely regulated at the state level. But with so many wells, there is not enough manpower in the states to sustain proper oversight. For example, 35 inspectors were responsible for 74,000 wells in Pennsylvania in 2008, 19 for 13,000 in New York, and 24 for 64,000 in Ohio (*The Nation*, 2011).

In recent years – and especially in the past several months – some states have taken legislative initiative to require the public disclosure of the chemicals in fracking fluids. According to FracFocus, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, the following states have or are developing laws concerning public disclosure: Wyoming, Pennsylvania, Arkansas, Texas, Colorado, New Mexico, Montana, West Virginia, Idaho, and North Dakota (FracFocus.com, n.d.). Most of these states’ laws require only the disclosure of chemicals, but some require the concentrations as well. However, because gas companies do not have to disclose the contents of their fracking fluids in most states, and there are very few federal mandates for such disclosure¹⁵ little is known about the proportions and exact ingredient mixes. A study by Colborn et al. (2011) identified 944 products used in natural gas operations. Of those, for only 14% (131) were 95-100% of the ingredients were known; for 43% (407), less than 1% of the total product composition was known. “For many of those 407 products, only the name of the product with no identifiable chemical name or percent composition was reported” (Colborn et al., 2011). Known product components totaled 632 chemicals.¹⁶

¹⁵ This may soon change, however, as the U.S. Department of the Interior has for months been working on new rules that would federally regulate fracking on public lands by requiring “energy companies to disclose the chemicals they use in fluids” during fracking. Additionally, it would “outline standards for wellbore integrity, aimed at preventing water contamination, and include requirements for how water used in the process is treated.” (*The Wall Street Journal*, 2012).

¹⁶ Under President Obama, the EPA has leaned on gas companies to voluntarily provide information about fracking fluid ingredients, but to no avail (*The Atlantic*, 2012).

The danger these chemicals present is serious, as many are either carcinogenic or associated with numerous health problems (Kargbo et al., 2011). Colborn et al. (2011) observe that of these chemicals, more than 75% can have adverse effects on the “skin, eyes, and other sensory organs, the respiratory system, the gastrointestinal system, and the liver.” Over 50% can have adverse effects on the brain and nervous system. Exposure to any of the chemicals in these categories could result in immediate “eye and skin irritation, nausea and/or vomiting, asthma, coughing, sore throat, flu-like symptoms, tingling, dizziness, headaches, weakness, fainting, numbness in extremities, and convulsions” (Colborn et al., 2011). Over 40% can cause chronic and long-term organ and system damage in the nervous system, immune system, kidneys, and the cardiovascular system, and more than 25% can cause cancer (Colborn et al., 2011). Colborn et al. (2011) also purport that over 40% of these chemicals have “other” effects, including effects on weight, teeth, bone, and even the possibility of death. Moreover, 37% of the chemicals are volatile, meaning not only can they be ingested as the water soluble chemicals can, but they can also be inhaled and absorbed through the skin, enhancing exposure risk (Colborn et al., 2011).

Recently, a new law passed in Pennsylvania allows doctors to access information about the chemicals used in fracking fluid, but precludes them from being able to share that information with their patients. According to a recent article in *The Atlantic* (2012),

“Pennsylvania law states that companies must disclose the identity and amount of any chemicals used in fracking fluids to any health professional that requests that information in order to diagnosis or treat a patient that may have been exposed to a hazardous chemical. But the provision in the new bill requires those health professionals to sign a confidentiality agreement stating that they will not disclose that information to anyone else – not even the person they're trying to treat.”

Industry has cast aside concerns about the chemicals used in their operations, citing the low concentrations of such chemicals – but as Colborn et al. (2011) point out in response, “many of the chemicals on the list should not be ingested at any concentration. Numerous systems, most notably the endocrine system, are extremely sensitive to very low levels of chemicals, in parts-per-billion or less.” And with so many pathways for contamination – fluid spills during transport, underground travel through natural and man-made fractures,

improper storage, and the dumping of effluent in surface water and open pits (which when not well-lined can leach into groundwater) – exposure to this array of chemicals is very likely to those living in the vicinity of gas production sites (*The Nation*, 2011; Volz, 2011).

The last pathway in that list, discharge of untreated contaminants into surface water, is the most common; it is the last step in the process of treating and disposing of flowback at Publically Owned Treatment Works (POTW) or Brine Treatment Facilities. Dr. Conrad D. Volz, a professor at the University of Pittsburgh’s Graduate School of Public Health and Director and Principal Investigator at the Center for Healthy Environments and Communities, testified before the Senate Committee on Environment and Public Works’ joint hearing “Natural Gas Drilling, Public Health and Environmental Impacts and warned the following of such practices:

“Contaminants untreated by the facility and discharged into surface water will move in the water through advective and fickian processes downstream, be deposited and transferred into sediments and pore water, bioaccumulate in aquatic receptors and terrestrial animals that feed on them according to their species specific bioaccumulation factors, be transported to groundwater, and/or be volatilized to air dependent on their Henry’s Law constants. Direct and complete human and ecological exposure pathways via ingestion, dermal absorption and inhalation (gill transfer in fish) can be demonstrated for different classes of elements, and compounds in the wastewater, constituting a potential exposure threat to recreationalists, private well water users and municipal drinking water users.”

5.2.1 Blacklick Creek effluent contamination case study

A well-documented example of just such a case in which wastewater effluent has been found to contaminate surface water is in Indiana County, Pennsylvania at the Pennsylvania Brine Treatment (PBT) Josephine Facility. This facility accepts wastewater from only the oil and gas industry; this includes flowback from shale gas operations in the Marcellus Shale. In their study – which, it is important to note, is *not* peer-reviewed – Volz et al. (2011) took samples of wastewater effluent as it was discharged into Blacklick Creek at 3-hour intervals over a 24 hour period. The report compares the concentrations of selected analyzed contaminants in the effluent water to “standards, guidelines and criteria set by federal and

state regulatory and investigative agencies for the protection of human and aquatic health,” including:

- the EPA’s maximum contaminant level (MCL), the legal limit on the amount of a substance allowed in public water systems under the Safe Drinking Water Act to prevent adverse health effects;
- the EPA’s secondary maximum contaminant level (SMCL), the recommended – but not legal – limit on the amount of a substance allowed in public water systems under the Safe Drinking Water Act to prevent aesthetic or cosmetic problems;
- the Agency for Toxic Substances and Disease Registry’s (ATSDR) minimal risk levels for men, women, and children (MRL – M, MRL – W, and MRL – C, respectively), the limit on the “daily human exposure to a hazardous substance that is not likely to pose an appreciable risk of adverse noncancerous health effects” (Volz et al., 2011);
- the EPA’s criteria maximum concentration (CMC), the “estimate of the highest concentration of a material in surface water to which an aquatic community can be exposed briefly without resulting in an unacceptable effect” (EPA, n.d.);
- the EPA’s criteria continuous concentration (CCC), the “estimate of the highest concentration of a material in surface water to which an aquatic community can be exposed indefinitely without resulting in an unacceptable effect” (EPA, n.d.); and
- the lower and upper levels requiring notification to the Pennsylvania Department of Environmental Protection (PA DEP) by the facility’s National Pollutant Discharge Elimination System (NPDES) permit (Volz et al, 2011).

The mean concentrations of the selected contaminants – barium, strontium, bromide, benzene, 2-butoxyethanol, magnesium, manganese, sulfates, total dissolved solids (TDS),¹⁷ and chlorides – are all compared to the various standards listed above in the context of how many times greater the mean sample concentrations were than the standards in Tables 2 and 3. A total of 15,728,241 gallons of oil and gas wastewater was treated by the PBT – Josephine Facility in the 6-month period from 1 July 2010 to 31 December 2010. Using this figure and the mean level of each contaminant found in the study, the total

¹⁷ High TDS in the Monongahela River in 2009 from the discharge of inadequately treated flowback “led the PA DEP to issue a water-quality-advisory for 325,000 customers to use bottled water” (Kargbo et al., 2011).

masses of each of these contaminants discharged during this period were determined and are also listed in Table 3.¹⁸

The results are staggering. For example, the mean concentrations of strontium and bromide are 745 and 10,688 times greater than their MCLs, respectively. Barium, strontium, benzene, and 2-butoxyethanol were all discovered in concentrations higher than

Tables 2, 3: Comparison of the concentrations of selected contaminants analyzed by Volz et al. (2011) in the effluent water in Blacklick Creek from the PBT – Josephine Facility to standards and guidelines set by various agencies for the protection of human and aquatic health

	Mean ppm	Max ppm	Times greater than MCL	Times greater than SMCL	Times greater than MRL - M	Times greater than MRL - W	Times greater than MRL - C
<i>Barium</i>	27.8	37	14		3.96	4.73	8.98
<i>Strontium</i>	2,981.1	3,120	745		43.29	51.68	97.9
<i>Bromide</i>	1,068.8	1,100	10,688				
<i>Benzene</i>	0.012	0.013	2.4		0.7	0.86	1.5
<i>2-butoxyethanol</i>	59	66			24.48	29.21	55.14
<i>Magnesium</i>	1,247.5	1,300					
<i>Manganese</i>	0.8			1.6			
<i>Chlorides</i>	117,625	125,000					
<i>Sulfates</i>	560	585		2.2			
<i>TDS</i>	186,625	190,000		373			

	Mean ppm	Max ppm	Times greater than CMC	Times greater than CCC	Times greater than PA DEP lower level	Times greater than PA DEP upper level	Total mass deposited in last 6 mos. of 2010 (kg)
<i>Barium</i>	27.8	37	1.3	6.7			1,627
<i>Strontium</i>	2,981.1	3,120			29,811	5,962	177,712
<i>Bromide</i>	1,068.8	1,100			10,688	2,138	63,708
<i>Benzene</i>	0.012	0.013					
<i>2-butoxyethanol</i>	59	66			590	118	3,517
<i>Magnesium</i>	1,247.5	1,300					
<i>Manganese</i>	0.8						
<i>Chlorides</i>	117,625	125,000	138	511			7,011,631
<i>Sulfates</i>	560	585					33,382
<i>TDS</i>	186,625	190,000					11,124,733

¹⁸ A search of the scientific literature for a standard against which to compare these data – for example, typical concentration values for the relevant contaminants in the effluent from POTWs that do *not* treat oil and/or gas – yielded no such background data; only the various parameters for quality could be found.

their respective MRLs. And even though strontium, bromide, and 2-butoxyethanol concentrations were found to be anywhere from 2 to 4 orders of magnitude higher than the limit requiring notification to the PA DEP,¹⁹ no such notifications were delivered in December 2010, the month in which samples were obtained. Clearly, the disposal of large quantities of wastewater from fracking through brine treatment plants and POTWs is ineffectual and has serious ramifications on stream and river systems, public water supplies, recreationalists, and private well water users.²⁰ “The PA DEP and other state and federal regulatory authorities should immediately review all surface water discharge permits granted to brine treatment facilities and POTWs” accepting flowback fluids from gas production operations to ensure that the concentrations of contaminants being discharged are below all associated standards and guidelines, Volz et al. (2011) conclude.

5.2.2 Treatment of flowback

Gregory et al. (2011) echoes the concerns of Volz et al. (2011) and argues that despite the current utilization of POTWs to manage flowback water, it is not an adequate or sustainable approach. But what other options are there for managing such high volumes of flowback water? As Gregory et al. (2011) report, there are alternatives, some of which are more economically feasible than others. These are summarized below:

- *Underground injection* – This is by and large the most common option in managing produced water from oil and gas production. Such operations utilize Class II (disposal) underground injection control wells as defined by the EPA. Some areas have an adequate supply of disposal wells, such as in Texas, where there is slightly more than one disposal well per gas-producing well in the Barnett Shale; some areas, however, have an entirely inadequate supply of disposal wells, as in Pennsylvania, where there are only 7 such disposal wells available. While this number is expected to increase as the Marcellus Shale is further exploited, constructing new disposal wells is complex, time-consuming, and costly.

¹⁹ Neither strontium, bromide, nor 2-butoxyethanol are listed on the PBT – Josephine Facility NPDES permit, but “the facility is required to notify the PA DEP if they routinely discharge 100 ppb of a toxic pollutant or nonroutinely discharge 500 ppb of a toxic pollutant” (Volz et al., 2011).

²⁰ In fact, New York City and Syracuse, two cities holding permits allowing them to provide unfiltered surface water for drinking, are at the mercy of shale gas operations in upstate watersheds, which could potentially contaminate their water resources with inadequate treatment and disposal (Cusolito, 2011).

- On-site reuse – Though not the most popular option, the reuse of flowback water in subsequent fracking operations is perhaps the most promising, especially in areas such as the Marcellus Shale where disposal wells are limited. After flowback water is impounded at the surface, it is either reused directly or – more likely – following dilution or pretreatment.²¹ Reusing flowback water minimizes the volume of water necessitating treatment or disposal, reduces environmental risks, and is extremely economical.
- Reverse osmosis – In this process, the flowback water is passed through a semipermeable membrane under pressure. This separates material ranging from suspended particulates to monovalent ions of salt from the water, resulting in a high quality treated water. After undergoing reverse osmosis, the consequent volume of concentrate can be as low as 20% of the initial volume of the flowback. However, because it is so energy intensive, it is considered economically infeasible for flowback with TDS concentrations higher than 40,000 ppm.
- Thermal distillation – By evaporating the flowback, the water is separated from its dissolved constituents, and the resulting vapor passes through a heat exchanger in which the vapor condenses, producing purified water from which 99.5% of dissolved solids have been removed. Though reducing treatment and disposal costs of flowback water by as much as 75%, this is an energy-intensive process. And even though distillation can treat flowback with high TDS concentrations (exceeding 125,000 ppm), it is limited to low flow rates and thus requires large storage impoundments.
- Crystallization – This process continues the thermal distillation process with further water evaporation, creating dry mineral crystals, allowing for the treatment of flowback with TDS concentrations as high as 300,000 ppm – but associated with crystallization are even higher energy requirements and capital costs.

Other treatment options include ion exchange and capacitive deionization (limited to the treatment of low-TDS water), freeze-thaw evaporation (limited to cold climates),

²¹ Pretreatment reduces the divalent cation concentration by precipitation, which helps to prevent reduction in gas production caused by the formation of stable carbonate and sulfate precipitates in the wellbore from the solubilized divalent cations (Gregory et al., 2011).

evaporation ponds (limited to arid climates), and artificial wetlands and agricultural reuse (limited by the salinity tolerance of fauna and flora) (Gregory et al., 2011).

5.3 Methane in drinking water?

Methane is already a concern associated with shale gas production as described earlier in the context of atmospheric pollution, but it might also be a legitimate concern in the context of shallow groundwater systems. In a controversial paper, Osborn et al. (2011a) examined the nature of this concern in the Catskill and Lockhaven formations (overlying the Marcellus Shale in Pennsylvania) and the Genesee Group (overlying the Utica Shale in New York). From these locations, 68 private water wells ranging in depth from 36 to 190 m were analyzed with measurements of dissolved salts, ^{18}O and ^2H , and isotopes of carbon, boron, and radium. Measurements of dissolved-gas concentrations of methane and higher-chain hydrocarbons and of carbon and hydrogen isotope ratios of methane were taken at 60 of those wells. They then compared the data from active production sites – those with one or more gas wells within 1 km – against nonactive sites – those with no gas wells within 1 km.

Osborn et al. (2011a) found methane concentrations in 51 of 60 drinking-water wells regardless of proximity to gas operations, but (as shown in Figure 7) concentrations of methane were on average 17 times higher in those closer to gas wells. The average of 19.2 ppm CH_4 in shallow groundwater near active drilling sites (contrasted with an average of 1.1 ppm CH_4 near nonactive sites) falls within the defined action level of 10-28 ppm for hazard mitigation, as recommended by the U.S. Department of the Interior, as it poses an asphyxiation risk in enclosed spaces and is an explosion and fire hazard (Osborn et al., 2011a).

But is the source of the methane shallower and biologically-derived (microbial), or deeper and physically-derived (thermogenic)? Osborne et al. (2011) use $\delta^{13}\text{C}_{\text{methane}}$ and $\delta^2\text{H}_{\text{methane}}$ values and the ratio of methane to ethane, propane, and butane (all higher-chain hydrocarbons) to make the distinction: deep, thermogenic methane have $\delta^{13}\text{C}_{\text{methane}}$ values less negative than -50‰ , while shallow, microbial methane have values $\delta^{13}\text{C}_{\text{methane}}$ values

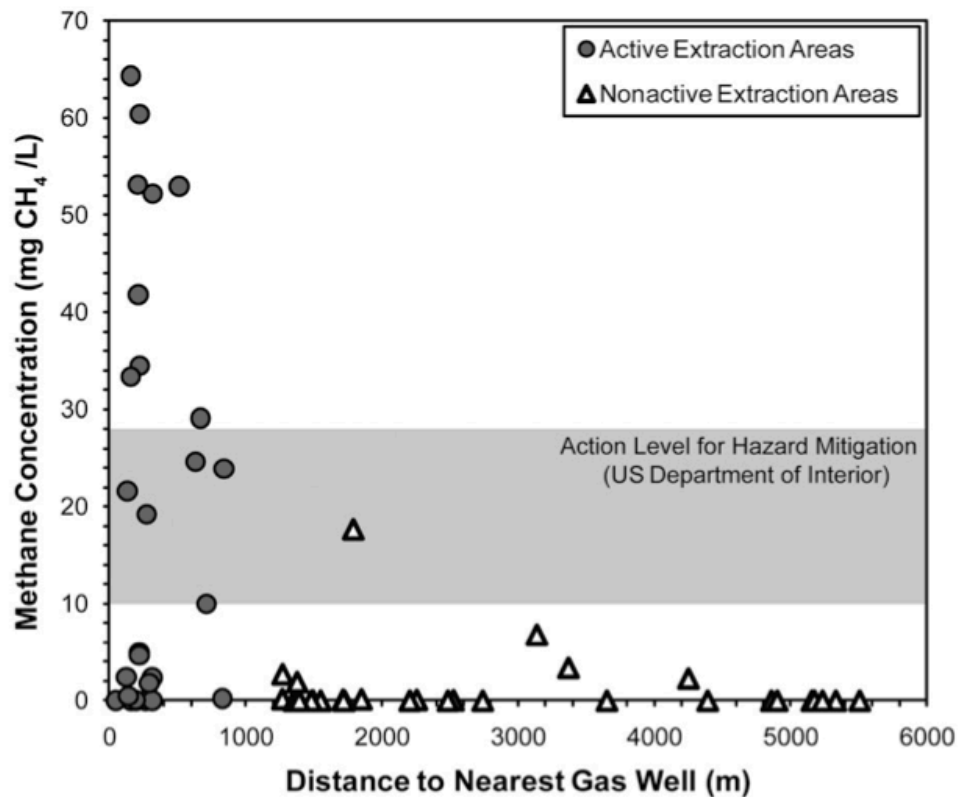


Figure 7: “Methane concentrations (milligrams of CH₄ L⁻¹) as a function of distance to the nearest gas well from active (closed circles) and non-active (open triangles) drilling areas” (Osborn et al., 2011a).

more negative than -64‰ ; additionally, larger ratios of higher-order hydrocarbons to methane are more indicative of a deep thermogenic origin (Osborn et al., 2011a).²²

Osborn et al. (2011a) found that the average $\delta^{13}\text{C}_{\text{methane}}$ value in shallow groundwater near active sites was $-37\pm 7\text{‰}$, implying a deep thermogenic source; their average $\delta^{13}\text{C}_{\text{methane}}$ value near nonactive sites, $-54\pm 11\text{‰}$, was less conclusive, implying a mixed methane source. In drinking-water wells from active sites, ethane, propane, and butane were detected in 21, 8, and 2 of 26 wells, respectively; to contrast, ethane was found in 3 of 36 wells from nonactive sites, and propane and butane were found in none (Osborn et al., 2011a). Not only did methane concentrations increase in proximity to wells (Figure 7), but so did the thermogenic nature of the source (Figure 8A). From this analysis, Osborn et al. (2011a) conclude that “thermogenic gas from thermally mature organic matter of Middle Devonian and older depositional ages is the most likely source of the high methane concentrations observed in the shallow water wells from active extraction sites.”

²² Also indicative of shallow, microbial methane are $\delta^2\text{H}_{\text{methane}}$ values more negative than -175‰ ; when combined with low $\delta^{13}\text{C}_{\text{methane}}$ values, a purer biogenic methane is implied (Osborn et al., 2011a).

Middle Devonian gas is often found in the Marcellus Shale at depths of approximately 900 to 1,800 m, while drinking-water wells range in depth from 60 to 90 m, creating a large vertical separation between the gas source and water supplies. Osborn et al. (2011a) propose three possible mechanisms for gas migration into shallow groundwater:

1. physical displacement of gas-rich deep solution from the target formation, which is unlikely given the lithostatic and hydrostatic pressures from the 1-2 km of overlying strata;
2. leaky gas well casings, which could occur at hundreds of meter underground, with “methane passing laterally and vertically through fracture systems”;
3. increased connectivity of fracture system caused by the generation of new fractures or enlargement of existing fractures above the target shale formation as a result of the fracking process, which, following the reduction in pressure from fracking, “could release methane in solution, leading to methane ex-

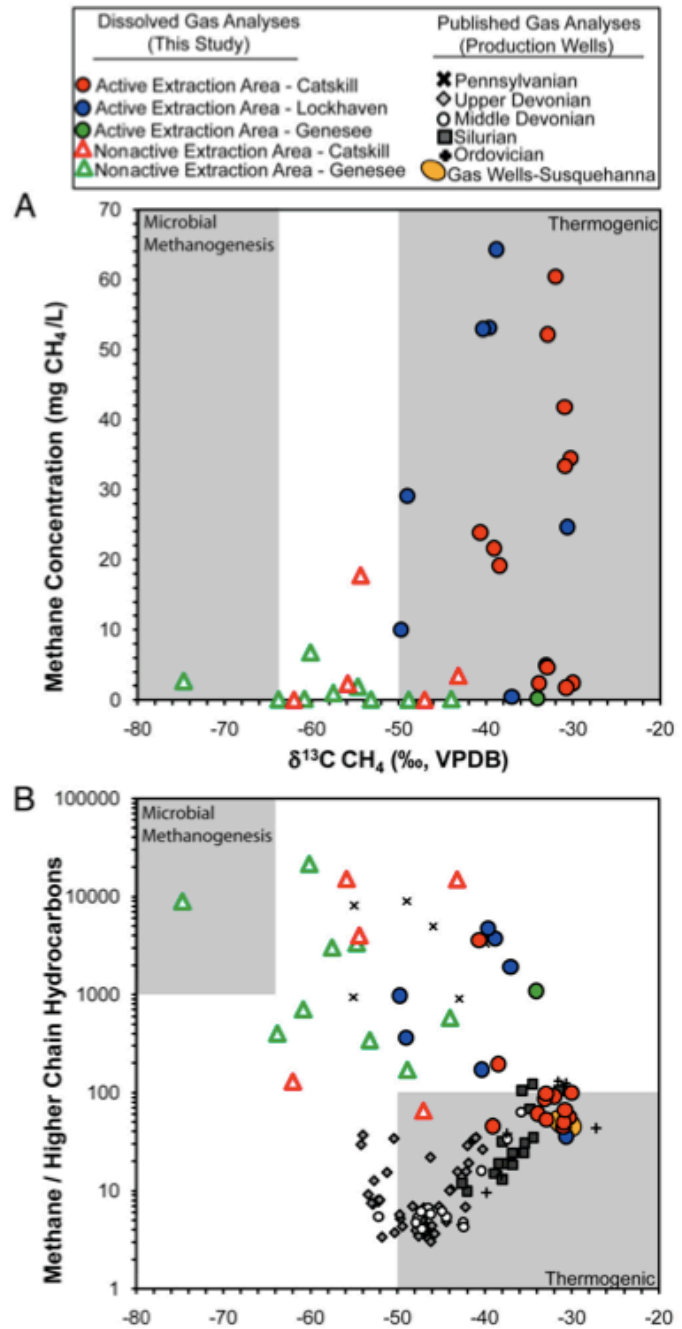


Figure 8: “(A) Methane concentrations in groundwater versus the carbon isotope values of methane. ... Gray areas represent the typical range of thermogenic and biogenic methane. ... (B) Bernard plot of the ratio of methane to higher-chain hydrocarbons versus the $\delta^{13}\text{C}_{\text{methane}}$ Gray areas represent typical ranges of thermogenic and biogenic methane.” (Osborn et al., 2011a).

solving rapidly from solution, allowing methane gas to potentially migrate upward through the fracture system” (Osborn et al., 2011a).

Osborn et al. (2011a) have received some criticism for their methods and their linking of fracking to the high concentrations of methane found in the shallow groundwater near active shale gas operations. Davies (2011) takes issue with the small size of the water well dataset, its nonrandom nature, and the large, geologically diverse area it covers. He notes that several of the water wells with high contamination came from Dimock, where in 2009 and 2010, “it was reported that aquifer contamination was caused by recent casing leaks in at least three wells rather than hydraulic fracturing.” Such leakage resulting from the inadequate cementing of gas wells is extensive, says Davies, as is natural seepage of methane. Davies (2011) calls out Osborn et al. (2011a) for not including critical pre-fracking methane concentration measurements, leaving open the possibility that some of the contamination is historical. Additionally, Davies points to microseismic and tiltmeter data that shows that the fractures produced from fracking operations in the Marcellus Shale are more than 1 km below the aquifers and are unconnected.

In defense, Jackson et al. (2011)²³ point out a few flaws in Davies’ (2011) reasoning. First, Osborn et al. (2011a) acknowledged that methane migration is a less likely mechanism for methane contamination than leaky well casings, but that still “does not rule out the possibility of fracture flow in a naturally fractured system” (Jackson et al., 2011). Second, Davies (2011) is wrong to invoke the role of gas migration through orphaned wells, as only 3 of the over 8,000 orphaned wells in Pennsylvania are found in the studied counties.²⁴ Ultimately, Davies’ (2011) issue with Osborn et al.’s (2011a) conclusion is the implication that fracking itself could possibly play a role, to which Jackson et al. (2011) respond

“Is it possible that hydraulic fracturing increases system connectivity? It is. Is it also possible that the increasingly high pressures used in hydraulic fracturing, sometimes 1,000 atm, make leaks more likely? Perhaps. Neither is proven, and all possible explanations need more research.”

²³ Jackson is the head author of the response instead of Osborn, though the response is penned by the same team of researchers as Osborn et al. (2011a).

²⁴ According to the PA DEP’s public database of gas well locations

Jackson et al. (2011) agree with Davies' (2011) call for microseismic and tiltmeter data, and further suggest the need for "better geographic and stratigraphic data on the isotopic distributions of methane and ethane with depth" and for a "public database of methane and ethane isotope values from each gas well."

Further criticism comes from Saba and Orzechowski (2011). They charge two points: first, that the only sampled water well in an active area in the Genesee gave a methane concentration (0.3 ppm) less than the average in nonactive area water wells (1.5 ppm), a correlation contrary to Osborn et al.'s (2011a) conclusion; and second, that wide isotopic variation across the Lockhaven water wells indicates a mix of natural gases, as opposed to from a single source, such as shale gas operations, in which methane isotopes would be more uniform across a small region. To support the latter point, they cite a 2005 investigation by the PA DEP in which Lockhaven water well samples from Tioga County, PA, were found to contain thermogenic methane with no relation to gas extraction.

In their rebuttal, Osborn et al. (2011b) dismiss the first criticism as arbitrary, as they sampled only one active water well in the Genesee "primarily to provide a baseline for future sampling after horizontal drilling and hydraulic fracturing occur." In response to the second charge, Osborn et al. (2011b) point out that not only is Tioga County outside of their study area, but extensive areas of the county have been used for commercial underground gas storage, which has led to documented leaks into well water. Contrarily, Osborn et al. (2011b) sampled a natural methane seep near to their study sites, Salt Springs State Park, and found that the isotopic signatures of its methane, which were thermogenic (-45.9‰ $\delta^{13}\text{C}_{\text{methane}}$) overlapped with the nonactive background Catskill samples, but not the active Catskill samples. "Not all 'thermogenic' methane is the same," Osborn et al. (2011b) conclude. "There are indeed low concentrations of thermogenic methane found across the region. That methane does not, however, look like the methane found in drinking water near gas wells."

While more research needs to be done, as Osborn et al. (2011a; 2011b) readily admit and encourage, it seems reasonable to trust Osborn et al.'s conclusion that fracking – whether the act of fracking itself or associated processes in shale gas production – poses a risk to

shallow groundwater sources via methane contamination. More data should be gathered at sites prior to gas operations to provide historical background values for comparison.

6. OTHER PITFALLS OF SHALE GAS

Beyond the dangers already considered, several other less studied, more anecdotal concerns have come to light. There is a slight risk of shallow gas blowouts and underground blowouts between subsurface intervals if permeable gas reservoirs are struck (Kargbo et al., 2011). Also likely to cause explosions are improper well casings, as was the case in 2007 in Bainbridge, Ohio, where an explosion blew a house off its foundation and left the town without drinking water, and in 2008 in Dimock, Pennsylvania, where a well explosion led to black, orange, or bubbly water. (A year later, 8,000 gallons of drilling fluids spilled out into nearby fields and creeks. In response, 15 families have filed suit against the gas company with primary leasing rights in the area alleging fraud and contract violation) (*The Nation*, 2011).

There is also concern about the possibility of inducing seismicity by accidentally triggering faults via both fracking and injection well disposal, resulting in small scale earthquakes (DOE, 2009a; Kargbo et al., 2011). Because operations sometimes take place in unexpected subterranean conditions, extraction and drilling could cause severe ground subsidence; furthermore, shale gas operations risk the disturbance and even the destruction of aquifers (Kargbo et al., 2011). The construction of well pads, service roads, and pipelines all make the protection of sensitive wildlife and habitats difficult, and also increase the amount of noise, light, and traffic in the area (DOE, 2009b; Kargbo et al., 2011; Schmidt, 2011).

Occasionally, the issue of mineral rights can cause great grief, as well: “many times mineral rights are owned by people besides the homeowner, which the homeowner may not even have realized at the time of purchase” (Schmidt, 2011).

7. RECOMMENDATIONS FOR THE FUTURE OF SHALE GAS

With so many concerns surrounding the production of shale gas, what can be done to mitigate the potential hazards to benefit from this resource? In 2010, President Barack Obama instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board to do determine just what could be done. After meeting, the

Subcommittee produced a report with a series of recommendations that they believe would enhance the safety and environmental performance of shale gas production. Generally, the Subcommittee stresses improving best practices, measurement, and disclosure. Specifically, they made the following recommendations to reduce environmental and safety risks associated with shale gas production (DOE 2011a; 2011b):

- *Improve air quality by reducing emissions of regulated pollutants and methane*

Rigorous standards should be adopted for new and existing sources of methane, air toxins, ozone precursors, and other air pollutants from shale gas production. Measurement systems should be implemented to collect emissions data, which should be made publically available. A federal interagency effort should be launched to gather such data to better analyze the GHG footprint on shale gas and compare it against other fuels. Proven technologies should be adopted to reduce emissions.

- *Protect water supplies and water quality*

At every stage of the shale gas production process, there should be “consistent measurement and public disclosure of the flow and composition of water.” Additionally, inspections should be required at safety-critical stages of well construction and fracking, including pressure testing of cemented casings, microseismic surveys to monitor fracture growth, and field studies to investigate possible methane leakages into water reservoirs.

- *Measure background water quality*

Requirements should be adopted for background water quality measurements, the availability of which in advance of drilling “would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.”

- *Disclose the composition of fracking fluids*

Though the Subcommittee believes the risk of fracking fluid contaminating drinking water sources to be remote, they believe there is “no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids,” and conclude that

“the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals.”

- *Reduce the use of diesel in shale gas development*

There is no technical or economic reason for the use of diesel engines; instead, natural gas or electric engines should be used where possible.

- *Manage impacts on communities, land use, wildlife, and ecologies*

Environmental and community impacts should be anticipated formally through regulated entities. These impacts can be mitigated by utilizing multi-well drilling pads to minimize traffic noise, evaluating water use in the context of affected watersheds, preserving unique or sensitive areas as off-limits to drilling operations, mitigating surface impacts to important landscapes and habitats.

Additionally, the Subcommittee made the following recommendations to encourage responsible and improved development of shale gas:

- *Make shale gas information available to the public*

A portal should be created so that a wide range of information on shale gas development from both state and federal regulatory agencies can be publically accessible.

- *Improve communication between state and federal regulators*

The State Review of Oil and Natural Gas Environmental Regulation (STRONGER) and the Ground Water Protection Council should continue to receive annual support so that the Risk Based Data Management System and other projects like it can be expanded.

- *Organize for best practice*

Create a shale gas industry production organization to continuously improve “techniques and methods that rely on measurement and field experience,” in order to improve “operational and environmental outcomes.”

- *Research and development*

Though the economic incentive for technical advances exists for research and development to occur mainly by the oil and gas industry, it is important that the federal government support research and development, especially in the promotion of environmental protection and safety. The Administration and Congress should set a research and development mission and allocate appropriate funding.

With all of these recommendations in consideration, regulators will have better and more complete information and industry will become more efficient, with continuous, measurable improvement. In doing so, shale gas resources can be responsibly developed and the public better informed.

8. CONCLUSION

Shale gas is a plentiful domestic resource that could prove to be a boon to the economy and provide thousands of jobs. However, legislation of exclusions and exemptions from most, if not all federal regulations has allowed industry to carry on without proper checks on the possible ramifications of shale gas production. As more research is done, it becomes clear that despite its benefits, shale gas poses serious risks to the environment, both locally and perhaps even globally in terms of accelerated climate change, and to human health. Fugitive methane emissions from shale gas operations need to be addressed, and flowback water needs to be properly treated and disposed of. In all areas of shale gas production, better care must be taken to ensure the safety and health of those at risk. It seems that too much haste has already had an impact in the form of improperly cemented well casings, leading to gas leaks, flowback spills, and even explosions. More transparency is also necessary, as the contents of fracking fluids have been proven to contain hundreds of chemicals, several of which are extremely hazardous to human health and the delicate ecosystems in which they are disposed. All of this should be taken into consideration when looking to shale gas as a “bridge fuel” that many hope to ride into a renewable future.

ACKNOWLEDGEMENTS

I would like to thank Bill Dornbos, the Associate Director of the Yale Center for Environmental Law & Policy, and Dave Bercovici, the Deputy Director of the Yale Climate & Energy Institute, for giving me an early interest in shale gas. I would also like to thank Mike Oristaglio not only for being the second reader to this essay, but for several helpful meetings and literature references. I am deeply grateful for the guidance of my advisor, Jay Ague, and for his suggestion to focus on the dichotomy that exists regarding opinion over the safety of shale gas fracking; his extremely helpful insight proved to be invaluable. I am also indebted to Gabriel Mejias for a stimulating discussion and extremely helpful literature recommendations. A shout out is also deserved of Dave Evans, my four-time professor, advisor, employer, and Director of Undergraduate Studies, who has been offering me sage words (sometimes in verse) and good times through almost all of my geological endeavors at Yale and abroad. Finally, I would like to thank the Yale Department of Geology & Geophysics on the whole for providing me with an undergraduate experience second to none – I am eternally grateful for the people, the opportunities, and the beer.

REFERENCES

- The Atlantic* (2012). "For Pennsylvania's Doctors, a Gag Order on Fracking Chemicals." *The Atlantic*. 27 Mar. 2012. Web. 1 Apr. 2012.
<<http://www.theatlantic.com/health/archive/2012/03/for-pennsylvanias-doctors-a-gag-order-on-fracking-chemicals/255030/>>.
- AQMD (2011). "Historic Ozone Air Quality Trends, 1976-2010." *South Coast Air Quality Management District*. Web. 16 Apr. 2012.
<<http://www.aqmd.gov/smog/o3trend.html>>.
- Boggs, Sam (1987). *Principles of Sedimentology and Stratigraphy*. 1st Edition. Columbus, Ohio: Merrill Publishing Company, 1987.
- Cathles, Lawrence M. (2012). "Assessing the greenhouse impact of natural gas." *G3*, 2012.
- Cathles, Lawrence M., Larry Brown, Milton Taam, and Andrew Hunter (2012). "A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea." *Climatic Change*, 2012.
- Scientific American* (2012). Chestney, Nina. "Global Warming Close to Becoming Irreversible: Scientific American." *Science News, Articles and Information*. 26 Mar. 2012. Web. 01 Apr. 2012.
<<http://www.scientificamerican.com/article.cfm?id=global-warming-close-to-becoming-ir>>.

- Colborn, Theo, Carol Kwiatkowski, Kim Schultz, and Mary Bachran (2011). "Natural Gas Operations from a Public Health Perspective." *Human and Ecological Risk Assessment* 17 (2011): 1039-1056.
- The Nation* (2010). Cusolito, Kara. "The Next Drilling Disaster?" *The Nation.*, June 21, 2010: 18-20.
- Davies, Richard J. (2011). "Methane contamination of drinking water caused by hydraulic fracturing remains unproven." *PNAS* 108, no. 43 (October 2011): E871.
- DOE (2011a). "90-Day Report .", Secretary of Energy Advisory Board, 2011.
- (2011b). "Second 90-Day Report." Shale Gas Production Subcommittee, Secretary of Energy Advisory Board, 2011.
- EIA (2011a). "Review of Emerging Reges: U.S. Shale Gas and Shale Oil Plays." *EIA*. July 2011. <ftp://ftp.eia.doe.gov/natgas/usshaleplays.pdf>.
- (2011b). "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States." *EIA*. April 2011. <http://www.eia.gov/analysis/studies/worldshalegas/>.
- Engleder, Terry (2011). "Should fracking stop? No, it's too valuable." *Nature* 477 (September 2011): 271-275.
- EPA (2011a) Inventory of greenhouse gas emissions and sinks 1990–2009, April 14, 2011. U.S. Environmental Protection Agency, Washington DC.
- (2011b). Oil and natural gas sector: standards of performance for crude oil and natural gas production, transmission, and distribution. EPA-453/R-11-002.
- (2011c). Regulatory Impact Analysis: Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Gas Industry. July 2011. U.S. Environmental Protection Agency, Office of Air and Radiation. Washington DC.
- (2011d). "Denver's Ozone Concentrations." *Environmental Protection Agency*. Web. 16 Apr. 2012. <<http://www.epa.gov/region8/air/planningsec/statedes/aqdenveroz.html>>.
- (n.d.). "National Recommended Water Quality Criteria." *United States Environmental Protection Agency*. Web. 01 Apr. 2012. <<http://water.epa.gov/scitech/swguidance/standards/current/index.cfm>>.
- FracFocus. "Chemicals & Public Disclosure." *FracFocus Chemical Disclosure Registry*. Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Web. 22 Apr. 2012. <<http://fracfocus.org/chemical-use/chemicals-public-disclosure>>.
- Gregory, Kelvin B., Radisav D. Vidic, and David A. Dzombak (2011). "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing." *Elements* 7 (June 2011): 181-186.
- Horwitt, Dusty (2009). "Statement of Dusty Horwitt, JD Senior Counsel, Environmental Working Group." Oversight Hearing "Draft Supplemental Generic Environmental

Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and Hydraulic Fracturing”, New York City Council Committee on Environmental Protection, New York City, NY, 23 October 2009.

Howarth, Robert W., and Anthony Ingraffea (2011). "Should fracking stop? Yes, it's too high risk." *Nature* 477 (September 2011): 271-275.

Howarth, Robert W., Renee Santoro, and Anthony Ingraffea (2011). "Methane and the greenhouse-gas footprint of natural gas from shale formations." *Climatic Change*, 2011.

— (2012). "Venting and Leaking of Methane from Shale Gas Development: Response to Cathles et al." *Climatic Change*, 2012.

Hultman N, Rebois D, Scholten M, and Ramig C (2011). The greenhouse impact of unconventional gas for electricity generation. *Environ. Res. Lett.* 6: 044008, doi:10.1088/1748-9326/6/4/044008

IPCC (1995). IPCC Second Assessment, Climate Change, 1995.
<http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf>

IPCC (2007). IPCC Fourth Assessment Report (AR4), Working Group 1, The Physical Science Basis.
http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html

Jackson, Robert B., Brooks Rainey Pearson, Stephen G. Osborn, Nathaniel R. Warner, and Avner Vengosh (2011). "Research and Policy Recommendations for Hydraulic Fracturing and Shale-Gas Extraction." Center on Global Change, Duke University, Durham, NC, 2011.

Jackson, Robert B., Stephen G. Osborn, Avner Vengosh, and Nathaniel R. Warner (2011). "Reply to Davies: Hydraulic fracturing remains a possible mechanism for observed methane contamination of drinking water." *PNAS* 108, no. 43 (October 2011): E872.

Jiang M., Griffin WM, Hendrickson C, Jaramillo P, vanBriesen, J and Benkatesh A (2011). Life cycle greenhouse gas emissions of Marcellus shale gas. *Environ. Res. Lett.* 6: 034014, doi:10.1088/1748-9326/6/3/034014

Kargbo, David M., Ron G. Wilhelm, and David J. Campbell (2010). "Natural Gas Plays in the Marcellus Shale: Challenges and Potential Opportunities." *Environmental Science & Technology* 44, no. 15 (2010): 5679-5684.

King, George E (2012). "Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells." *Hydraulic Fracturing Conference*. The Woodlands, TX: Society of Petroleum Engineers, 2012.

MIT (2011) "The Future of Natural Gas." Multidisciplinary examination of various energy sources, Massachusetts Institute of Technology, Cambridge, MA, 2011.

Nisbet EG, Manning MR, Lowry D, Lassey KR (2000) Methane and the framework convention on climate change, A61F-10, *Eos Trans. AGU* 81(48). Fall Meet Suppl

- Osborn, Stephen G., Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson (2011a). "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing." *PNAS Early Edition* (2011).
- (2011b). "Reply to Saba and Orzechowski and Schon: Methane contamination of drinking water accompanying gas- well drilling and hydraulic fracturing." *PNAS* 108, no. 37 (September 2011): E666.
- Pierrehumbert R (2011)
<http://www.realclimate.org/index.php/archives/2010/12/losing-time-not-buying-time/>
- Reuters* (2011). "Obama backs shale gas drilling." *Reuters.com*, January 25, 2011.
- Saba, Tarek, and Mark Orzechowski (2011). "Lack of data to support a relationship between methane contamination of drinking water wells and hydraulic fracturing." *PNAS* 108, no. 37 (September 2011): E663.
- Schmidt, Charles W. (2011). "Blind Rush? Shale Gas Boom Proceeds amid Human Health Questions." *Environmental Health Perspectives* 119, no. 8 (August 2011): A348-A353.
- Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, and Bauer SE (2009). Improved attribution of climate forcing to emissions. *Science* 326: 716-718.
- Shindell D, and others (2011). Simultaneously mitigating near-term climate change and improving human health and food security. *Science*, in press.
- Skone TJ, Littlefield J, and Marriott J (2011). Life cycle greenhouse gas inventory of natural gas extraction, delivery and electricity production. Final report 24 Oct 2011 (DOE/NETL-2011/1522). U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA.
- UNEP/WMO (2011). Integrated Assessment of Black Carbon and Tropospheric Ozone: Summary for Decision Makers. United Nations Environment Programme and the World Meteorological Organization. Nairobi, Kenya.
- Volz, Conrad D., et al (2011). "Contaminant Characterization of Effluent from Pennsylvania Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, Pennsylvania." Executive Summary, Department of Environmental and Occupational Health, Graduate School of Public Health, University of Pittsburgh, Pittsburgh, PA, 2011.
- Volz, Conrad Daniel (2011). "Written Testimony of Conrad Daniel Volz, DrPH, MPH." Joint Hearing "Natural Gas Drilling, Public Health and Environmental Impacts", Subcommittee on Water and Wildlife, Senate Committee on Environment and Public Works, Washington, D.C., 2011.
- The Wall Street Journal* (2012). Tracy, Tennille. "House Republican Vows To Halt Fracking Rules Amid Tribal Concerns." 19 Apr. 2012. Web. 22 Apr. 2012.
<<http://online.wsj.com/article/BT-CO-20120419-719065.html>>.