The Physical and Legal Implications of Continued Fracking in the Marcellus Shale Gas Basin

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Abstract:

In this paper we offer physical and legal arguments on the issue of harvesting shale gas as a means of reducing our carbon footprint associated with the generation of electricity. From the legal and regulatory views it is clear that extant law has little applicability to shale gas mining operations despite the significant potential of harmful effects to nearby land owners, water quality in the relevant watersheds, and to the consumer. Furthermore there are significant porosity variations in these shale deposit such that drilling and fracking in "leaky" environments is possible and is allowed under current regulations. At these sites, more methane may be leaking to the atmosphere than is captured by the wellhead. Our physical argument is based on a model to develop 200 gigawatts (GW) of new nameplate generation capacity by the year 2020 by comparing the infrastructure need for shale gas harvesting to that needed for wind energy. For wind, we require 70,000 2.5-3 MW new wind turbines to be built out to 2020. Each of these non-GHG producing turbines can provide electricity for 25 years. In contrast, due to rapid rates of production decline, an individual well-head has a 3-4 year useful lifetime. To reach 200 GW nameplate of shale gas then will require the construction of 50,000 new well heads from now until 2020. In turn, this NG fired electricity would produce a cumulative total of 7.5 gigatons of CO_2 emission over this time period. Furthermore, these built out well heads (including the dry ones) would ultimately cover 15% of the state of Pennsylvania. From this model comparison, we easily conclude that the harvesting of shale gas for new electricity generation is not scalable or sustainable with respect to our 200 GW target goal.

I. **Introduction**

In this article we critically examine the overall impact of harvesting shale gas located in the Marcellus Shale Basin as the principal means of reducing US greenhouse gas (GHG) emission that is associated with the generation of electricity. We begin by discussing, in the context of total US greenhouse gas emissions, whether or not the increasing use of natural gas (NG) as a source of electricity generation is an effective "low carbon" alternative to coal. We next construct an electricity generation model based on increasing US nameplate[1] electrical generation capacity by 20% from its 2010 value by the year 2020. A 20% increase from 2010 levels is approximately 200 GW of new generation infrastructure. This proposed increase is a reasonable extrapolation from previous trends. From available generation data[2] US name plate capacity was approximately 750 Gigawatts[3] (GW) in 1990, 835 GW in 2000, and 1139 GW in 2010. Thus over the 20 year period 1990 through 2010, nameplate capacity increased by 47%. We directly compare the facility of reaching that goal by either shale gas infrastructure or wind energy infrastructure. Following the presentation and discussion of that model we move into the legal and regulatory aspects of hydraulic fracking include local land use law, mineral rights, water rights, and applicable federal law including EPA regulations and tax incentives.

[1] Nameplate capacity represents the physical capacity of a generation device; this can be less than the operational capacity

[2] Unless otherwise indicated, all facts and figures for this article were obtained from various data tables available at the Energy Information Administration Web

[3] Throughout electrical capacity is either stated in Terrawatts (TW), Gigawatts (GW), or Megawatts (MW)

II. Environmental Issues

a) Coal vs. Natural Gas and associated GHG emissions

There is no question that NG fired electricity is increasing and has been touted as a “low carbon” alternative to coal. In this context, NG can be considered as a bridge fuel. In November of 2011, for the first month ever, coal fired electricity fell to less than 40% of total US generation due to gains made in NG fired electricity. While some might view this as reinforcing the assertion that NG is an effective bridge fuel, that statistic only creates the illusion of a decarbonized electrical grid as our total GHG emission continues to grow due to increasing consumption (see also Nelson etal 2012). We note that NG emits about ½ as much carbon emission per generated MW as coal.

We begin by setting the numerical context of electricity generation in the US and the role of natural gas (NG) in that generation. Total generator nameplate capacity is a measure of direct investment in infrastructure. In 2008, US nameplate capacity was 1.104 Terawatts (TW); by 2010 this had risen to 1.139 TW through capacity additions (primarily NG and wind) of 35,000 MW. In 2010, coal nameplate was 342 GW while NG was 467 GW. In 1990 those nameplates capacities were 330 GW coal compared to 153 GW NG. Currently NG is operating strictly as a capacity addition which serves to increase total US GHG emission. To show this we normalize 330 GW of coal to 2 coal units of emission; 153 GW NG then equates to 0.46 units leading to 2.46 units of emission in 1990. For 2010, coal is 2.07 units while NG has risen to 1.4 units for a total emission of 3.47 units or a 41% increase in GHG emissions associated with increasing electricity generation over the last 20 years. This trend will continue if NG remains strictly a capacity addition instead of a 1 for 1 replacement for coal fired electricity.

b) **200 GW of new facilities by 2020: Wind vs. Shale Gas**

By the end of 2012 the US will have an installed wind nameplate capacity of 53 GW. In 2011 and 2012 approximately 13 GW has been installed using mostly 1.5 MW turbines yielding a deployment rate of 4,300 turbines per year. In the near future, wind farms will install 2.5 MW turbines with 3 MW considered the limit (due to transporting the blades) for any land based wind farm. Our model assumes continued investment that allows for a 15% annual growth rate in turbine build out over the 2013-2020 period (this is a lower growth rate than the current rate of about 23%; we adopt this lower rate as its unclear if the production tax credit for wind installation will continue throughout until 2020). We further assume that 2.5 MW turbines will be installed from 2013-2016 and then 3 MW turbines installed from 2017-2020. As shown in the graph below, this model produces 68,000 new turbines with combined nameplate capacity of 200 GW by the end of 2020:

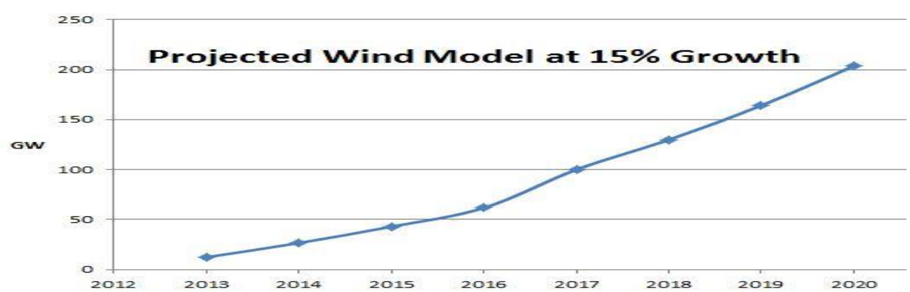

Figure 1: Model cumulative build out of wind nameplate capacity from 2013 to 2020

We next estimate the wellhead infrastructure needed to produce 200 GW of nameplate capacity in the Marcellus shale basin. In 2011 total US Natural Gas Consumption was 24.3 TCF[4]. Of this 14.2 TCF is used for space heating; 7.6 TCF is used to generate electrical power at the 467 GW current nameplate capacity of NG. This scaling yields 3.3 TCF (per year) necessary to produce 200 GW of NG fired electricity. As 75% of the Marcellus resource is contained in Pennsylvania (PA) we will use that data[5] as the basis for our model. Table 1 summarizes recent well head construction in PA:

Table 1: Well Head Construction in PA

Year	**Well Heads Constructed**
2008	**185**
2009	**770**
2010	**1385**
2011	**1850**
Through 9/2012	**1065**
Total:	**5315**

[4] TCF = trillion cubic feet; MCF = million cubic feet
[5] All data come from the State of Pennsylvania Dept. of Environmental Protection Website

The 2012 data suggest that wellhead build-out is no longer increasing at the rate that was previously established as its on pace to be less than 2011. In 2011 on average 5 wellheads per day were constructed. Data for July 2012 show that this has declined to 2.5 well heads per day. This decline in well head construction is consistent with the 2012 NG production data for PA (Figure 2) which shows asymptotic behavior indicating that PA is now at peak production of 5.8 BCF per day from its combined 5000-5500 well heads operational since 2008.

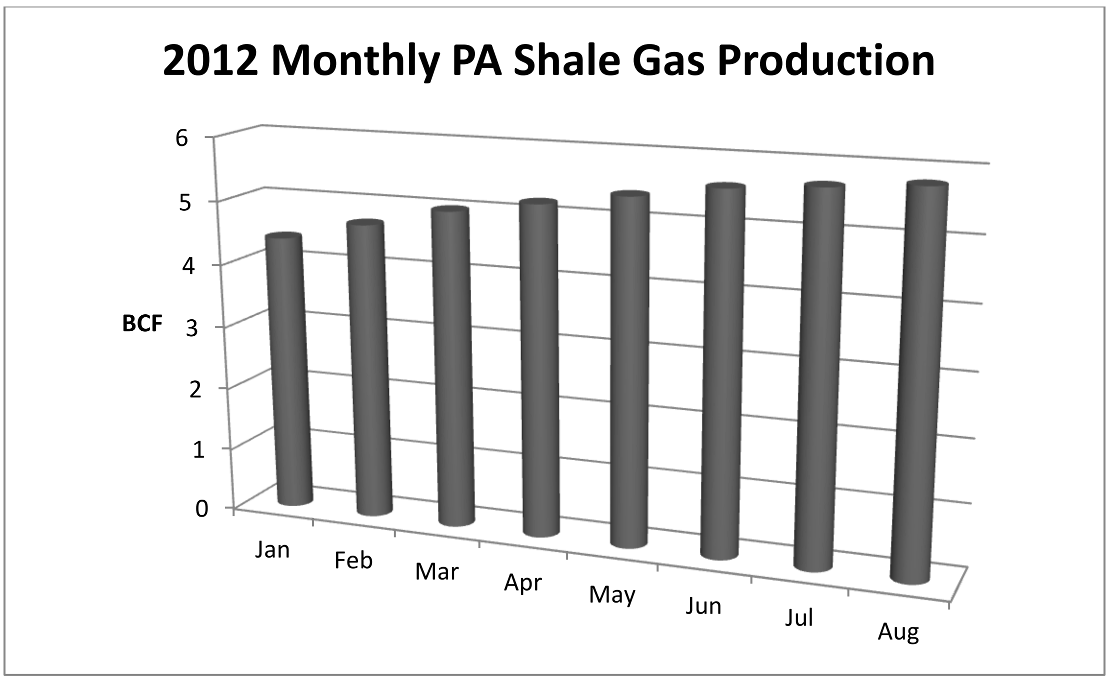

Figure 2. Monthly averages of shall gas production in PA in units of BDF per day. Data Source: Bertek Energy (EIA)

Figure 2 shows an increase of about 1.3 BCF per day from Jan to August. This increase is the result of about 1,000 new wells coming on line during this period. Thus a new well-head yields an average of 1.3BCF/1000 = 1.3 MCF at peak production. But peak production declines (significantly) with time as the pressure inside the well head drops. The estimated ultimate recovery (EUR) from a given wellhead is currently a contentious issue between the industry and independent studies, due to strong differences in formal mathematical models of individual well head decline[6]. While complex hyperbolic functions are often used (e.g. Mason 2011; England etal 2000) to formally compute daily well head declines, we take a simpler approach by using a simple exponential decline as we are interested in declines of production on years timescales rather than months.

Much individual gas field data can be found at www.hdpi.com. Averaging several raw data sets we end up with a formal exponential decline rate of 0.3 +/- 0.05% per day. We adopt this value for the well heads in the Marcellus shale basin. This rate of decline means that production reaches a level of 34% of peak after just one year and falls to 4% after three years. Hence any annual yield comes from wellheads constructed over the most recent 3 year period. Our model also uses a somewhat high initial production rate of 2 MCF per day (recall the data suggests 1.3 MCF) for a PA Marcellus new well head. Using 2MCF as initial peak production and the 0.3% per day decline rate yields the following scenario: if 2,000 new wells were (hypothetically) built in 2012 and turned on for one year starting Jan 1 2013 they would produce approximately 1.1 TCF of NG for 2013, 0.4 TCF in 2014 and 0.1 TCF in 2015 The combined 3 year sum is 1.6 TCF or about ½ of the 3.3 TCF target value needed for 200 GW of nameplate production. Therefore to reach 3.3 TCF would require the building of 4,000 new wells every year for each 3 year period out to 2020 to maintain a constant supply for electricity production.

[6] See the extensive discussion at http://www.theoildrum.com/node/8212

If the initial yield was 1 MCF per day then 8,000 new wells per year would need to be built. Averaging between these values means building 6,000 new wells per year or 16 wellheads a day; 7 times larger than the current rate of deployment. At a current well head surface density of 8 per square mile this would mean that, on average**,** PA would acquire about 750 square miles of abandoned well head surface area per year. A possible alternative is re-fracking every 3 years but re-fracking permits in PA have declined sharply[7] in 2012. In addition, re-fracking requires significant water resources (see section III.b below) and provides additional stresses on aging well-casings.

Moreover, on a 25 year timescale our model wind energy build out would yield 200 GW*0.4 (capacity factory)*25 years = 17,250 TW-hrs of total electricity generated with 0 GHG emissions. In comparison, at a constant value of 2000 well heads per year (closer to real world numbers), assuming 1 MCF initial yield, we reach a nameplate capacity of ~100 GW operating at about 90% capacity factory. Over the same 25 year period this produces slight more energy (19,710 TW-hrs) but would require installing 50,000 well-heads occupying approximately 15% of the available land area in PA. In addition, 7.5 Gigatons of CO_2 emissions would also be incurred.

c) Estimated yields of the Marcellus Basin

The proper way to estimate the exhaustion timescale of any resource that is consumed is given by the expression below (see Bartlett 1978:)

$$\mathbf{T_e = 1/k * \ln (Rk/r_o +1)}$$

[7] http://www.examiner.com/article/drilling-permits-decline-sharply-for-the-pennsylvania-marcellus-formation

Where k represents annual exponential consumption increase, R represents the total estimated recoverable reserve, and r_o is the initial use. The peak time (**T_p**) occurs at ½ **T_e.** In Table 2 we assume that all the estimated TCF in the Marcellus shale formation will be used for electricity generation and that the resource can be (theoretically mined) to scale with an annual increase of 2% in demand (driven by current low prices). We use an initial value of r_o = 1.5 TCF per year, consistent with the optimistic value previously derived. There are extremely large variations in the overall estimated yields. More recent estimates are much less optimistic than the earlier estimates. Based on these assumptions, Table 2 calculates the values for the peak times as a function of yield estimate.

Table 2: Marcellus Basin Reserve Estimates and Exhaustion Timescales

Year of Estimate	Yield Estimate (TCF)	Agency	T_p (years)
2002	31	USGS[8]	8
2008	392	Engelder and Lash (2008)	45
2009	500	Engelder (2009)	50
2009	1500	Dept. of Energy	76
2011	84	USGS	19
2011	410	EIA	46
2012	141	EIA	26

[8] United States Geological Survey

The relatively small values for $\mathbf{T_p}$ (particularly for the most recent 2012 estimate) provide a clear indication that harvesting the available shale resource is only a short term solution to increasing electricity demand; the reserves simply are not big enough to scale to demand over the long term.

III. **Regulatory and Legal Issues**

The first section of this article addressed some of environmental issues related to fracking in the Marcellus Shale Formation. This section will focus on legal and regulatory aspects of fracking in the Marcellus Shale formation. A primary goal of legal and regulatory frameworks is to limit the harmful impact from resource extraction under a variety of extraction scenarios.

a) Shale Rock Characteristics:

The potential damage to humans, animals, and water resources caused by fracking depends on the physical characteristics of the particular shale gas deposit. Soeder (1988) demonstrates that significant variations exist in the porosity and permeability of the shale gas deposits throughout the northeastern US. Due to the potential extraction of shale gas (see Soeder 2010), there have been a flood of more recent studies (e.g. Eseme etal 2007; Passey et al 2010; Sondergeld et al 2010; Curtis et al 2011;). Porosity and permeability characteristics within shale formations determine the amount of “gas flow” that can occur and the overall efficiency of extraction. Explosive release (e.g. hydraulic fracking) of trapped gas can have a wide range of outcomes depending upon these physical characteristics. Simply put, shale gas that is entrained in rock with high porosity/permeability will more readily “leak” to places other than the intended well head pipe. Mining operations in these kinds of formations enhance the probability of methane release to the environment.

Pipeline leaks can also vent methane into the atmosphere. In August of 2011, the US Department of Transportation issued a safety order[9] on the newly constructed Millennium pipeline in New York for apparently faulty welds. Santoro et al (2011) and Howarth et al (2011,2012) have both argued that the combined effects of these processes may be leading to more methane release to the atmosphere than is actually captured by the well-head/pipeline infrastructure. While the magnitude of well head or pipeline leakage remains controversial (and under studied) it nevertheless raises the issue that porosity and permeability characteristics of each individual shale deposit should become part of the scientific basis for regulation and permitting.

b) Water Usage Details

Since large volumes of water are required to drill the wellhead, large volumes of waste water are generated by this drilling process. This wastewater is considered by the Susquehanna and Delaware River Basin commissions to be industrial wastewater and the permitting process must identify where drillers plan to obtain and store their water and to specify their rate of water withdrawal. Drillers must also specify where the produced wastewater will be stored and properly treated. According to a 2012 study by Chesapeake Energy 5.6 million gallons[10] of water per well are needed for the initial fracking or re-fracking process. For 6000 wells per year, this is a daily water usage of 90 million gallons all of which needs to be regulated and monitored to be in compliance with existing codes.

Drilling down a few thousand feet should protect groundwater resources from contamination, but flaws in well casings may result in leakage. Between 15 to 80 percent of the

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[9] http://primis.phmsa.dot.gov/comm/reports/safety/psi.html?nocache=8805
[10] http://www.chk.com/media/educational-library/fact-sheets/marcellus/marcellus_water_use_fact_sheet.pdf

fracking fluid is recovered as “flowback”[11]. The flowback fluid is contaminated with the fracking chemicals as well as salts, metals, and radioactive chemicals that come out of the rock itself. Fracking wastewater is a combination of flowback liquid and waste water. The wastewater is typically stored in surface containment ponds until it can be treated and either pumped into permanent storage wells or discharged into surface water. In some cases, the wastewater is reused as fracking fluid. Contaminants may find their way to groundwater or the surface by way of abandoned gas wells or natural fractures. In addition, methane from fracking operations may migrate to drinking water wells. While methane does not affect the potability of the water, it does pose an asphyxiation and explosion hazard when it moves from the water into the air, for example, when an indoor tap is turned on (Jackson et al., 2011).

c) Potential Harmful Impacts

Reports detail many instances of animal and human injury attributed to fracking. (Bamberger & Oswald 2012). Inadvertent release of fracking fluids into a cow pasture killed 17 cows in one hour. Out of sixty cows that were exposed to where fracking wastewater was dumped, 21 died, and 16 failed to produce calves the next spring. Reproductive and neurological problems were most commonly reported among the animals studied. Some of the exposed animals continued to produce milk and meat products that were sold for human consumption without testing of the animals or products. The animals’ owners most frequently suffered from respiratory symptoms, headaches, and gastrointestinal problems. In addition, numerous fish kills in Pennsylvania have been attributed to fracking operations. (Dutzik, Ridlington, & Rumpler, 2012).

[11] Tiemann, et al., 2012 Marcellus Shale Gas, CRS p. 11

d) Applicable/Inapplicable Federal Law

Fracking is exempt from most federal environmental laws. The Clean Water Act (CWA) specifically exempts oil and gas operations from federal storm water regulations. (33 U.S.C. § 1362(6)). Fracking operations are subject to the CWA requirements for discharge into surface waters, although the CWA's regulatory program is not comprehensive and does not include pretreatment requirements for fracking wastewater. (33 U.S.C. § 1251 et seq.) The Resource Conservation and Recovery Act (RCRA) exempts natural gas exploration wastes from federal regulation. 42 U.S.C. § 6901 (Ch 82). The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) excludes natural gas and natural gas liquids from its definition of hazardous substance, although fracking fluids are not specifically exempted. 42 U.S.C. (CERCLA) § 101(14). The oil and gas industry is exempt from reporting releases of toxic materials under the Emergency Planning and Right to Know Act (EPCRA). 42 U.S.C. § 11047 (Ch 116). The Safe Drinking Water Act (SDWA) does not apply to injections of fracking fluid for gas recovery purposes (unless diesel fuel is used). 42 U.S.C. § 300h(d). The SDWA does apply to disposal of fracking wastewater by injection, but fracking wastewater is not considered hazardous and can be disposed of in Class II wells, subject to less stringent requirements than Class I wells for hazardous waste. The EPA directly implements the Underground Injection Control (UIC) program in New York and Pennsylvania. Ohio and West Virginia have assumed primacy as allowed under the SDWA and implement their own UIC programs. 42 U.S.C. § 300h-4.

The fracking exemption under SDWA was added by the Energy Policy Act of 2005 (P.L. 109-58, § 322), which also limited the applicability of the National Environmental Policy Act (NEPA, 42 U.S.C. ch 55) review procedures to oil and gas well expansions. The provision in the Energy Policy Act may have originated with a recommendation by the National Energy Task Force that technologically advanced resource extraction techniques, such as fracking, should be exempted.[12] In 2004, the EPA published a study of fracking's impact on public water supplies, concluding that fracking posed little risk to water supplies[13]. A 2007 Washington Post[14] article noted that the Energy Task Force was dominated by industry groups and excluded the views of environmental groups. Congress has since requested the EPA to revisit the issue, and the final report is expected in 2014. (P.L. 111-88, H. Rept. 316).

E. State Law

Although fracking largely escapes federal regulations, it is subject to a number of state and local laws and regulations. State laws govern the permitting process, the drilling and fracturing process, production operations, management and disposal of wastes, and abandonment and plugging of the well. In some states, local authorities may also regulate well placement and operations. Fracking may provide significant financial benefits to state and local governments in the form of tax revenue, impact fees, and employment. Thus, the governmental authorities may have conflicting interests: protecting citizens' rights to clean water and encouraging economic growth. On the other hand, polluting streams and water sources can have a negative impact on economic growth, as damage to aquatic systems can have impacts on local businesses. In Pennsylvania, fishing had an economic impact of $1.6 billion in 2001. (Dutzik & Ridlington 2012).

A. New York

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[12] National Energy Policy 2001, p. x & 5-6.
[13] EPA National Study Final Report 2004.
[14] Michael Abramowitz and Steven Mufson, Papers Detail Industry's Role in Cheney's Energy Report, Washington Post A01, July 18, 2007.

New York's fracking industry is regulated by the Department of Environmental Conservation (DEC). New York has particular cause to be concerned about water pollution. New York City's water supply comes from pristine upstate New York watersheds that need no water filtration. (Dutzik & Ridlington 2012). These upstate watersheds sit atop the Marcellus Shale formation. If the watershed were to become polluted, the cost of building a filtration plant would be significant. In 2009, Governor Patterson issued an executive order[15] putting a moratorium on new fracking permits until an environmental impact statement could be updated. (The supplemental generic environmental statement (SGEIS) is required by the State Environmental Quality Review Act (SEQRA). The SGEIS notes that DEC's existing oil and gas well regulations will need to be revised to face the new challenges of fracking. On September 20, 2012, Governor Cuomo announced that the moratorium will continue until the health commissioner analyzes the health effects of fracking. The oil and gas extraction industry is a very small portion of total employment in New York, less than 0.01 percent of the state's total employment[16]. The Park Slope Food Cooperative, which buys more than $3 million worth of products from upstate farms, has told farmers its members will not buy products from any area that allows fracking, due to fear of contamination.[17]

B. Pennsylvania

The Pennsylvania Department of Environmental Protection (PADEP), Office of Oil and Gas Management, administers the state laws and regulations relating to fracking. In the Marcellus Shale formation, over 12,000 drilling permits have been issued since the first fracking

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[15] Ex. Ord. 41 (2009).

[16] (NYSDEC, Economic Assessment Report 2011)

[17] Mary Esch, Fracking in New York: For Farmers, Gas Drilling Could Mean Salvation—Or Ruin, Huffington Post, May 20, 2012

operations began in 2005. The PADEP increased the size of its enforcement staff to 130 employees, 65 of which are inspectors. In 2010, each Pennsylvania oil and gas inspector was responsible for, on average, 1,092 active wells. Pennsylvania has seen some of the most spectacular environmental problems from fracking, including methane gas incursions into drinking water wells, resulting in flaming water coming out of household taps. In response, in 2011, the legislature amended 25 Pa. Code Ch 78 to update regulations for the drilling, casing, cementing, testing, and monitoring of oil and gas wells. The PADEP issued 1,192 violations to drilling companies in 2011, but only six percent of those violations resulted in fines, which totaled $2.4 million[18]. In February 2012, the Pennsylvania legislature enacted Act 13, which removes local municipalities' power to ban drilling, requiring drilling to be allowed in all zoning districts. The legislation faces a legal challenge from municipalities[19].

In addition to the zoning override, Act 13 allows doctors to receive information about fracking chemicals, but if the doctors receive such information, they must agree not to disclose it to their patients. A Pennsylvania doctor has challenged this provision under 1st Amendment grounds. *Rodriguez v. Krancer*,[20]. Act 13 also imposes an impact fee on drillers of $50,000 per well for horizontal wells. Five percent of the impact fees, estimated to raise a total of $206 million in 2012, are earmarked for infrastructure improvements to attract drillers[21]. The most recent legislation, enacted Oct. 9, 2012, opens up state public university campuses to fracking operations[22].

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[18] (Clean Water Action Report: Few Penalties for Violated Gas Drilling Rules (June 8, 2012).

[19] Inglar, Communities see Marcellus law as striking at the heart of autonomy, Post-Gazette July 26, 2012
[20] 12 CV-01458 (M.D. Pa. July 27, 2012)
[21] Morgan, Impact Fees Bring $10 Million for Infrastructure Improvements, shalereporter.com (Oct. 8, 2012)
[22] Brownstone, Pennsylvania Fracking Law Opens Up Drilling on College Campuses, Mother Jones Oct. 12, 2012

C. Ohio

In 2004, H.B. 278 gave the Ohio Department of Natural Resources sole authority to regulate oil and gas wells, removing any authority by local governments. More recent legislation includes the doctors' "gag rule" similar to Pennsylvania's Act 13. In 2011, Ohio opened up its parks and other state-held lands for drilling. 140 permits for horizontal drilling into Marcellus Shale formation have been issued by the Ohio Department of Natural Resources. Ohio charges a resource severance fee of $0.025/1,000 cubic feet of natural gas. While drilling in Ohio is far behind Pennsylvania, Ohio's big contribution to fracking is in wastewater disposal. West Virginia and Pennsylvania ship most of their wastewater to Ohio for disposal. Ohio had 177 active Class II injection wells that absorbed almost 370 million gallons of wastewater in 2011. In 2012, Ohio increased its penalty for violation of storage regulations for natural gas fluids to a maximum of $20,000 per day in violation. (15 ORC ch 509 (2012)). Ohio collected only $17,500 in penalties in 2011.[23]

D. West Virginia

The Office of Oil and Gas of the West Virginia Department of Environmental Protection (WVDEP) is responsible for regulating fracking in West Virginia. Between 2002 and 2008, the WVDEP issued over 2,800 permits for drilling in the Marcellus Shale formation[24]. West Virginia drilling permit costs are low ($600 per permit), but the state charges a 5 percent severance fee based on the value of the extracted fuel.

[23] Oil and Gas Drilling Enforcement data by state, http://www.eenews.ent/special_reports/ground_rules

[24] Paul J. Nyden, WVU Study Details Marcellus Shale permits, income, The Charleston Gazette (Jan. 25, 2011)

The WVDEP Office of Environmental Advocate publishes a guide for citizens outlining how to file complaints, although it has not been updated for the most recent legislation. In 2010, West Virginia imposed $87,710 in drilling violation penalties. In 2011, the West Virginia legislature enacted its Horizontal Drilling Act (H.B. 401), which emphasizes the positive employment aspect of fracking in its first section (§5B-2B-4a.) However, the legislation specifically preserves the common law rights of injured plaintiffs and creates a rebuttable presumption for litigation purposes that the drilling of a horizontal well is the proximate cause of any contamination of fresh water supply that occurred within 1,500 feet of the center of the well pad. (§22-6A-18). The WVDEP has also promulgated standards for centralized pits for wastewater disposal and casing and cementing standards for drilling. This legislation has restricted the rights of municipalities to regulate fracking. In Northeast Natural Energy LLC v. City of Morgantown, the court allowed a mining company to circumvent Morgantown's ban on hydraulic fracking, holding that the city ordinance was preempted by state law. Civil Action No. 11-C-411 (Cir. Ct. W. Va. Aug. 12, 2011).

F. River Basin Commissions

River basin commissions are regional governmental agencies created for the purpose of planning for conservation, use, development and management of the water and related natural resources of the basin. Three river basin commissions cover the Marcellus Shale formation: the Delaware River Basin Commission (DRBC), the Susquehanna River Basin Commission (SRBC) and the Ohio River Basin Commission (ORBC). The DRBC and SRBC are interstate compacts approved by Congress with the force of law. Each has one representative from each participating state and a representative from the federal government. The federal representative is a member of the Army Corps of Engineers. In 2010 DRBC drafted regulations[25] requiring all natural gas plans in the region to be approved by the commission. These include Natural Gas Development Plans (NGDP), water withdrawals, and water treatment and discharge plans.

The State of New York and various non-governmental organizations (NGOs) sued the DRBC, seeking to require the DRBC to consider NEPA requirements in its final natural gas permitting regulations[26]. The Court dismissed the case without prejudice, finding that the plaintiffs lacked standing and deeming it premature as the final regulations had not been issued yet. In order to have standing a plaintiff must show 1) injury-in-fact; the injury is an actual or imminent, concrete and particularized, invasion of a legally protected interest; 2) causation; a fairly traceable causable connection to the injury; and 3) redressability; it is likely that a favorable decision will redress the plaintiff's injury. The Court stated that New York has a proprietary interest in the case in order to protect land, wildlife, and residents from pollution. The NGOs also have an interest through their members who use the area for hunting, hiking, skiing, boating, agriculture, and drinking water.

The SRBC was established after the DRBC and includes New York, Pennsylvania, and Maryland. Marcellus Shale lies under more than 72% of the river basin. Unlike the DRBC, the SRBC only regulates water withdrawals from surface and groundwater.[27] The SRBC only uses Approval by Rule, which is the equivalent of a permit from another agency. Companies may obtain approval from the SRBC by using other agency's regulations as their own as long as the regulations have already been pre-approved by the commission. The SRBC usually attaches

[25] Natural Gas Development Regulations, Delaware River Basin Commission, art. 7 part III Dec. 9, 2010
[26] (New York v. Army Corps of Engineers, 1L-CV-2S99, Sept. 24, 2012 (E.D.N.Y)
[27] (Susquehanna River Basin Commission, *The Susquehanna River Basin Commission's Role in Natural Gas Development*, Sept. 24, 2012 http://www.srbc.net/stateofsusq/documents/NaturalGasDevelopmentFeatureArticle.PDF)

"passby flows" conditions, low-flow regulations, to each approval. While the SRBC does monitor water quality, the commission left water quality regulation to the states and the federal government. The commission is in the process of erecting 30 monitoring stations between NY and PA to record real-time water quality data.

The ORBC is the least active of the three commissions. It was dissolved in 1981 by President Reagan because it "accomplished its goals." After being re-established, ORBC now acts to protect waters in Illinois, Indiana, Kentucky, Maryland, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia. It also works in conjunction with the Ohio River Valley Water Sanitation Commission (ORSANCO)[28], which represents IL, IN, OH, KY, WV, VA, PA, and NY.

G. Common law

More than forty lawsuits have been filed in state and federal courts alleging injury or damage from fracking operations. (Hill et al., Shale Development and Fracking Litigation, Blank Rome Legal Intelligencer (July 31, 2012). Most of these claims are based on common law theories of liability, such as public nuisance, private nuisance, trespass, negligence, negligence per se, or strict liability for abnormally dangerous activities. In Fiorentino v. Cabot Oil & Gas Corporation, the plaintiffs (who were depicted in the movie Gasland) sought property and personal injury damage based on negligence, private nuisance, strict liability, and the Hazardous Sites Cleanup Act. *Fiorentino v. Cabot Oil & Gas Corp.*, 750 F. Supp. 2d 506 (M.D. Pa. Nov 15, 2010). The plaintiffs alleged that Cabot had negligently conducted fracking operations that

[28] http://www.marcellus-shale.us/ORSANCO.htm

allowed the release of methane, natural gas, and other toxins onto plaintiff's land and into their groundwater. This case was settled in August 2012. No. 09-CV-2284

IV. Conclusion:

In this paper we examined the issue of harvesting shale gas in the Marcellus shale basin from both an environmental and legal/regulatory framework. From the legal and regulatory views it is clear that extant law has little applicability to shale gas mining operations despite the significant potential of harmful effects to nearby land owners, water quality in the relevant water sheds, and to the consumer. The lack of strong statutory and regulatory control allows for drilling to occur at any location, irrespective of the physical porosity and permeability of the local shale formation which is being drilled and fracked. There is little to no evidence of the application of scientific analysis to this permitting process. In addition, there is evidence of pipeline leakage associated with faulty well heads as well as direct leakage of methane, a potent GHG, into the atmosphere at individual fracking locations. From the scalability view we have argued that a) the estimated size of the harvestable resource is not large compared to current NG use and increasing demand b) the rapid rate of decline of individual well head yield requires a very large commitment to building new wells to make up for these losses. Our model shows that sustainability of shale gas yield (in PA), at the level of 3.3 TCF per year needed to produce 20% more national electricity generation, requires building approximately 6,000 new well heads a year occupying a total of 750 square miles. In turn, this well head build out would produce 7.5 Giga tons of CO_2 emission from these 50,000 individual well heads (occupying 15% of the size of the state of PA) that would need to be built over the period from now until 2020. In contrast, an equivalent nameplate production could be achieved by building 70,000 non GHG emitting wind turbines over the rest of this decade and that array of wind turbines would have production lifetimes of 25 years compared to the 3 useful production life time of an individual shale gas well head.

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