

**UP IN THE AIR: THE FUTURE OF
ENVIRONMENTAL MANAGEMENT FOR
HYDRAULIC FRACTURING WILL BE
ABOUT AIR, NOT WATER**

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UP IN THE AIR: THE FUTURE OF ENVIRONMENTAL MANAGEMENT FOR HYDRAULIC FRACTURING WILL BE ABOUT AIR, NOT WATER

JIM WEDEKING*

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I. INTRODUCTION

When word circulated that an obscure film called *Gasland* showed a Colorado homeowner igniting their tap water in January 2010, the clarion call of opposition to hydraulic fracturing has been allegations of water pollution. The visual image of exploding tap water was so emotionally captivating that it completely obscured the Colorado Oil and Gas Conservation Commission's earlier findings that the source of methane in the homeowner's well was naturally occurring and "unlikely" to be attributed to shale gas production.¹ The *Gasland* "flaming faucet" anecdote is emblematic of the errant focus on hydraulic fracturing as a source of groundwater con-

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1. Letter from John Axelson, Colorado Oil & Gas Conservation Commission, to Mark Markham at 5-6 (Sept. 30, 2008), available at <http://ogccweblink.state.co.us/results.aspx?classid=02&id=200190138> (document number 1984779). The Colorado Oil & Gas Commission's analysis of Mr. Markham's well water samples determined that it contained high levels of methane but lacked the presence of propane, iso-butane, butane, isopentane, pentane, and hexane, which are consistent with "thermogenic gas originating from deeper gas producing formations." *Id.* at 5. The methane was consistent, however, with biogenic methane, the product of near-surface organic decomposition common throughout Weld County, Colorado. *Id.*

tamination; stentorian and frenzied accusations that have, to date, never withstood scrutiny.

Although the oil and gas industry is devoting substantial resources to fending off recriminations, unsupportable regulations, and dubious studies about the potential impacts on groundwater, many regulators and industry personnel are sensibly shifting their attention to air emissions from oil and gas operations. Within a few years, concerns over hydraulic fracturing as a source of groundwater contamination will dissipate as government studies run their course, toxic tort suits largely fail, and shale development continues without the predicted catastrophic impacts on drinking water. Responsible management of air emissions, however, will be the environmental management issue that will require long-term attention.

This article examines several aspects of regulating air emissions from hydraulically fractured wells that have both arrived and will soon emerge. Part II of this article will review emerging issues related to criteria and hazardous air pollutant emissions. These issues include new EPA regulations, known as the Oil & Gas NSPS, as well as the recent ozone non-attainment designations for largely rural Rocky Mountain States which accommodate a lot of oil and gas development. Part III discusses a series of challenges to how oil and gas wells, and their related processing facilities, are permitted under the Clean Air Act. A series of new policies and new court cases are determining when and how separate wells and processing facilities can be treated as a single “stationary source” under the Title V and Prevention of Significant Deterioration permitting programs. Part IV of this article covers the regulation of greenhouse gas emissions from oil and gas wells, including EPA’s current indirect approach to controlling fugitive methane emissions and the potential for future direct regulations.

II. HYDRAULIC FRACTURING AND EMISSIONS OF CRITERIA AND HAZARDOUS AIR POLLUTANTS

Natural gas operations, both upstream and downstream, are extensively regulated under the Clean Air Act or similar state laws. Gas wells themselves, which are connected to a pipeline, generally do not emit air pollutants other than potential fugitive emissions around piping connections and pumps. Each well, however, is surrounded by several emission sources during the drilling, completion, and production phases of its life. For drilling and completion, wells require diesel engines to run the drill rigs, mix hydraulic fracturing fluid, and inject those fluids into the well bore. During production, the well is surrounded by hydrocarbon and produced water storage tanks, dehydrators, compressors, pumps, separators, and tank batteries.² All of this equipment emits some type of air pollution, including various organic compounds (hexane, benzene, toluene, ethylbenzene, xylenes), hydrogen sulfide, or sulfur dioxide.³ The engines used to power drill rigs and completion activities can emit nitrogen oxides (“NO_x”), carbon monoxide, volatile organic compounds (“VOCs”), and formaldehyde.⁴ Hydraulic fracturing generally involves a

2. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738-01–52,744 (Aug. 23, 2011).

3. *Id.* at 52,745.

4. See Table 1, 40 C.F.R. § 60.4231 (2013); Table 2, 40 C.F.R. § 63.6600 (2013).

greater use of diesel engines than conventional wells.⁵ Nevertheless, emissions from all of this equipment are regulated under the Clean Air Act's New Source Performance Standards, the National Emission Standards for Hazardous Air Pollutants, or both.⁶

The New Source Performance Standards ("NSPS") set "the degree of emission limitation achievable through the application of the best system of emission reduction" after considering various limiting factors such as cost, and non-air quality health and environmental impacts.⁷ NSPS limits are generally based on a type of control technology, referred to as "BSER,"⁸ specific to a category of stationary sources subject to the NSPS.⁹ EPA sets standards for whatever air pollutants that are emitted from an industry category, such as electric generating units or sulfuric acid plants.¹⁰ This allows the agency to perform a "comprehensive and coordinated" review of all source emissions while also "reviewing multiple regulatory programs together whenever possible . . ."¹¹

EPA's National Emission Standards for Hazardous Air Pollutants ("NESHAPs"), created under section 112 of the Clean Air Act, set emission limits for hazardous air pollutants ("HAPs") in a similar manner.¹² As with the NSPS, EPA takes a category-by-category approach in evaluating emissions and setting limits.¹³ NESHAPs, however, differ in a few important respects. First, there is a threshold limit of emissions; NESHAPs only apply to "major sources" of HAPs.¹⁴ Major sources are those with a potential to emit ten tons or more of any listed HAP¹⁵ or twenty-five tons of any combination of HAPs.¹⁶ Second, instead of BSER, emission limits are subject to more stringent maximum achievable control technology standards.¹⁷ Third, every eight years, EPA must review its NESHAPs for "residual risk" to determine whether they provide adequate protection for public health.¹⁸

5. *Id.*

6. *See e.g.*, 42 U.S.C. § 7411(a) (2012).

7. *Id.* § 7411(a)(1).

8. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. at 52,741.

9. *See* 42 U.S.C. § 7411(b)(1)(A) (providing that the EPA Administrator designates categories of stationary sources that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare").

10. *Id.*

11. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. at 52,743-44.

12. 42 U.S.C. § 7413.

13. *See* 42 U.S.C. § 7412(b).

14. *Id.* § 7412(a).

15. *See id.* § 7412(b)(1) (listing hazardous air pollutants).

16. *Id.* § 7412(a)(1).

17. *See id.* § 7412(d)(2) & (3).

18. *Id.* § 7412(f)(2); *see also* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 76 Fed. Reg. 52,741-43 (Aug. 23, 2011) (giving a more detailed explanation of the residual risk process).

The EPA Administrator first listed the oil and gas production sector as a source category under the NSPS in 1979.¹⁹ EPA revised these standards in 1985²⁰ and has only recently revised them a second time.²¹ EPA regulates the engines used at well sites to generate electricity and power equipment under other New Source Performance Standards.²² Emissions from oil and gas wells and related processing and compression facilities are separately regulated under various state programs.²³ Although oil and gas operations are relatively small on an individual level, the shale boom led to a proliferation of drill rigs in several areas of the country.²⁴ The cumulative emissions have started to attract some attention. What follows below are some of the likely issues that could potentially drive new air emission regulations for oil and gas operations, including those that use hydraulic fracturing.²⁵

A. The Oil and Gas NSPS

EPA issued its revised New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants for the oil and natural gas sector

19. Priority List and Additions to the List of Categories of Stationary Sources, 44 Fed. Reg. 49,222-01 (Aug. 21, 1979).

20. See Standards of Performance for New Stationary Sources; Equipment Leaks of VOC from Onshore Natural Gas Processing Plants, 50 Fed. Reg. 26,122-01 (June 24, 1985); Standards of Performance for New Stationary Sources; Onshore Natural Gas Processing SO₂ Emissions, 50 Fed. Reg. 40,158-01 (Oct. 1, 1985).

21. See generally Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule, 77 Fed. Reg. 49,489 (Aug. 16, 2012).

22. See Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 C.F.R. § 60.4200 (2013) (New Source Performance Standards for stationary compression ignition internal combustion engines); Standards of Performance for stationary spark ignition internal combustion engines, 40 C.F.R. § 60.4230 (2013) (New Source Performance Standards for stationary spark ignition internal combustion engines); National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 C.F.R. § 63.6580 (2013) (National Emission Standard for Hazardous Air Pollutants for reciprocating internal combustion engines). EPA most recently amended the reciprocating internal combustion engine standards on January 15, 2013. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 77 Fed. Reg. 33,812 (Jan. 15, 2013), available at <http://www.epa.gov/ttn/atw/rice/20130114amendments.pdf> (final rule signed but not yet published).

23. See, e.g., 25 PA. CODE §§ 127.401–04 (2013) (Pennsylvania operating permit requirements for air contaminant sources); 58 PA. CONS. STAT. ANN. § 3227 (West 2012) (Pennsylvania air emission reporting requirements specific to unconventional oil and gas operations); 3 WYO. DEP'T OF ENVTL QUALITY, AIR QUALITY §§ 1–3, 5–7 (2012) (general emission standards for all stationary sources); 6 WYO. DEP'T OF ENVTL QUALITY, AIR QUALITY §§ 2–3 (2012) (Wyoming operating permit requirements for newly constructed and modified sources); WYO. DEP'T OF ENVTL QUALITY, PROPOSED REVISIONS TO THE CHAPTER 6, SECTION 2 OIL AND GAS PRODUCTION FACILITIES PERMITTING GUIDANCE (Mar. 2010) (discussing presumptive Best Available Control Technology for non-major oil and gas emission sources, flaring destruction efficiency requirements, among others).

24. The extraction of natural gas from shale has grown from two percent of all domestic natural gas production in 2001 to twenty-three percent in 2010. U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2012, 3 (2012) available at [http://www.eia.gov/forecasts/aeo/pdf/0383\(2012\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf).

25. Air emissions can originate from every facet of the natural gas production process, including the processing, transportation, and distribution of natural gas. See Oil and Natural Gas Sector: New Source of Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 76 Fed. Reg. 52,738, 52,744 (Aug. 23, 2011) (to be codified at 40 C.F.R. pts. 60 and 63). This paper is restricted only to those emissions attributable to the drilling and completion of unconventional wells that are likely to use hydraulic fracturing.

(“Oil & Gas NSPS”) in August 2012.²⁶ This was the first time that EPA updated the Oil & Gas NSPS since 1985,²⁷ meaning that this was the first time that the agency considered air emissions from hydraulic fracturing. It set new standards to reduce emissions from several different processes in the oil and natural gas industry, including compressors, pneumatic controllers, glycol dehydrators, storage tanks, and processing plants.²⁸ Of interest here are its new requirements for onshore gas wells.²⁹ The Oil & Gas NSPS primarily targeted VOC and HAP emissions with respect to the well drilling and completion stage (i.e., the portion that uses hydraulic fracturing).³⁰ In fact, the “completion” stage was the subject of a major new control strategy imposed by the Oil & Gas NSPS. A brief explanation of the “completion” process is required.

After a natural gas well is drilled, it must be “completed” before it can produce gas. The completion process includes stringing and cementing the well casing, perforating the casing in preparation for hydraulic fracturing, and stimulating the well by injecting fluids under high pressure.³¹ After stimulation, plugs and debris are drilled out, and the fluid flows back up the well to the surface.³² During this flowback period, which can take anywhere between three and ten days, liberated gas gradually mixes with the flowback fluid.³³ The well cannot be connected to a sales line until the pressure decreases, and the amount of fluid and other impurities, such as VOCs, carbon dioxide or nitrogen, significantly decline.³⁴ Until then, the hydrocarbon portion of the flowback is generally flared, burning off into mostly carbon dioxide.³⁵ Once the flowback turns almost completely to gas, the well is connected to a pipeline and enters its production stage.

26. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. 49,490 (Aug. 16, 2012) (to be codified at 40 C.F.R. pts. 60 and 63).

27. Oil and Natural Gas Sector: New Source of Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 76 Fed. Reg. at 52,741 (Aug. 23, 2011) (proposed rule). EPA revised the Oil & Gas NSPS pursuant to a 2010 consent decree with WildEarth Guardians and San Juan Citizens Alliance. *Id.* at 52,743.

28. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. at 49,492 (Aug. 16, 2012) (to be codified at 50 C.F.R. pt. 17).

29. Onshore oil wells are not subject to the new standards given their low VOC emissions. EPA estimated that the cost for controlling emissions at oil wells would be between \$520,000 and \$700,000 per ton of VOC reduced. Oil and Natural Gas Sector: New Source of Performance Standards and Nat'l Emission Standards for Hazardous Air Pollutants Reviews 76 Fed. Reg. at 52,759 (to be codified at 40 C.F.R. pts. 60 and 63).

30. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. at 49,492.

31. EPA, OIL & NATURAL GAS SECTOR: STANDARDS OF PERFORMANCE FOR CRUDE OIL & NATURAL GAS PROD., TRANSMISSION, & DISTRIBUTION 4-1 (2011), available at <http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf> [hereinafter NSPS TSD].

32. *Id.*; Mary Lashley Barcella, Samantha Gross, & Surya Rajan, IHS CERA, *Mismeasuring Methane, Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development*, 2 (August 2011) [hereinafter IHS REPORT], available at, <http://www.ihs.com/images/MisMeasuringMethane082311.pdf>.

33. *Id.* at 2; NSPS TSD, *supra* note 31, at 4-1 to 4-2.

34. IHS REPORT, *supra* note 32, at 2-3.

35. *Id.* at 4.

During the life of a producing well, gas volumes may decline.³⁶ Returning the well to prior production levels may require a “recompletion” of the well. This may involve re-fracturing the well, fracturing a new producing zone, cleaning out paraffin buildup, or replacing portions of the tubing.³⁷ A recompletion requiring new stimulation with hydraulic fracturing fluid will involve the same high pressure flowback described above, where the well is only re-connected to the sales line when it is producing gas again.³⁸

The Oil & Gas NSPS will require well owners and operators to use “reduced emission completions,” also known as “green completions,” for all well completions and re-completions.³⁹ The regulations define a green completion as routing well flowback to a system that separates the flowback water, sand, natural gas liquids, and natural gas.⁴⁰ This will generally involve additional tanks, separator traps, and a wellhead dehydrator.⁴¹ Well operators are not subject to any numeric standards. Instead, they have only “a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.”⁴² Using methane as a surrogate for VOCs,⁴³ EPA estimated that the green completion requirements will control approximately twenty-three tons of VOCs per well completion or re-completion.⁴⁴

Although the lack of a numeric standard and the beneficial recovery of gas means that the green completion and flaring requirements are not especially onerous or expensive for industry, EPA refused industry’s request to apply its de minimis exemption for “modifications” to recompleted wells⁴⁵ and declined to exempt hydraulically fractured wells with little to no VOCs in the flowback.⁴⁶ In exchange,

36. See EPA, INSTALLING PLUNGER LIFT SYSTEMS IN GAS WELLS 1 (2006), available at http://epa.gov/gasstar/documents/ll_plungerlift.pdf.

37. EPA, *supra* note 31, at 4-2 to 4-3.

38. *Id.* at 4-3.

39. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. 49,490, 49,492 (Aug. 16, 2012) (to be codified at 40 C.F.R. pts. 60 and 63). The compliance date for the use of green completions is January 1, 2015. *Id.* Between the dates of October 15, 2012 and January 1, 2015, wells subject to the green completion requirements must flare their flowback emissions. *Id.* at 49,497. Gas wells are exempted from the green completion requirements where doing so is not technically feasible, would create unsafe conditions, or where the well is a wildcat, delineation, or low-pressure well. *Id.* at 49,544. Wildcat and delineation wells are only required to flare methane and VOC emissions because there are no gathering lines to which they could connect and recover gas. *Id.* at 52,757. Due to the unpredictable slug flow of gas during completions and the large, open flame, flaring is not required when it would create hazardous conditions, such as during dry, windy conditions, or if prohibited by local ordinances. Procurement List Additions, 75 Fed. Reg. 52,724, 52,728 (Aug. 27, 2010) (additions to the procurement list).

40. Oil and Natural Gas Sector: New Source of Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 76 Fed. Reg. 52,738, 52,757 (Aug. 23, 2011) (proposed rule).

41. EPA, *supra* note 31, at 4-14.

42. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. 49,544 (Aug. 16, 2012) (to be codified at 40 C.F.R. pts. 60 and 63).

43. *Id.* at 49,513.

44. Oil and Natural Gas Sector: New Source of Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 76 Fed. Reg. 52,757 (Aug. 10, 2011) (to be codified at 50 C.F.R. pt. 17).

45. *Id.* at 49,512–13.

46. *Id.* at 49,515–16.

EPA granted industry's request to extend the compliance date for green completions by two years to January 1, 2015 due to a shortage of equipment and trained personnel to install the equipment.⁴⁷ Until then, emissions must be flared.⁴⁸

Most of the provisions were generally well received by industry, in part, because several jurisdictions already required green completions for hydraulically fractured wells under certain circumstances,⁴⁹ and industry generally flared gas while attempting to capture the salable methane flow as quickly as possible.⁵⁰ Although both industry and environmental groups are challenging various aspects of the Oil & Gas NSPS in court, the general requirements for green completions with flaring are not a part of those challenges.⁵¹

One aspect of the Oil & Gas NSPS that has riled environmental groups, however, is EPA's decision not to regulate nitrogen oxide ("NO_x") emissions from well completions and re-completions, citing NO_x controls under other applicable NSPS regulations.⁵² In fact, EPA determined that the Oil & Gas NSPS flaring requirements to reduce ozone will result in an additional 550 tons per year of NO_x emis-

47. *Id.* at 49,517–19. Note that the issues described above are just the controversies involving the green completion and flaring standards that affect hydraulically fractured wells. Both industry and environmental groups had several other bones of contention with the remainder of the NSPS and NESHAP that apply to downstream sources. The views of industry and environmental groups are generally described in the following comments: CRAIG SEGALL ET AL., COMMENT ON NEW SOURCE PERFORMANCE STANDARDS: OIL AND NATURAL GAS SECTOR; REVIEW AND PROPOSED RULE FOR SUBPART OOOO, (Nov. 30, 2011), available at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4240>; DEVORAH ANCEL ET AL., COMMENT ON NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: OIL AND NATURAL GAS SECTOR; REVIEW AND PROPOSED RULE FOR 40 C.F.R. PART 63, (Nov. 30, 2011), available at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4457>; AM. PETROLEUM INST., REQUEST FOR ADMINISTRATIVE RECONSIDERATION AND AN ADMINISTRATIVE STAY OF TARGETED ELEMENTS OF EPA'S FINAL RULE "OIL AND NATURAL GAS SECTOR: NEW SOURCE PERFORMANCE STANDARDS AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS REVIEWS" (Aug. 16, 2012), available at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4590>.

48. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. 49,490, 49,492 (Aug. 16, 2012) (to be codified at 40 C.F.R. pts. 60, 63).

49. Colorado, Wyoming, and the cities of Fort Worth and Southlake, Texas have already required green completions. *Id.* at 49,517.

50. IHS REPORT, *supra* note 32, at 10.

51. See Non-Binding Statement Of Issues to Be Raised By Petitioners in Case No. 12-1410, Am. Petroleum Inst. v. EPA, No. 12-1405, (D.C. Cir. Nov. 16, 2012). Environmental groups are challenging various hazardous air pollutant emissions standards for glycol dehydrators, EPA's review of hazardous air pollutant standards for the industry sector as a whole, the agency's maximum achievable control technology review for the source category. See *id.* Industry petitioners have not yet filed their statement of issues; however, several trade associations filed petitions for reconsideration and a request for a stay of the rule with EPA. See, e.g., AM. PETROLEUM INST., REQUEST FOR ADMINISTRATIVE RECONSIDERATION AND AN ADMINISTRATIVE STAY OF TARGETED ELEMENTS OF EPA'S FINAL RULE "OIL AND NATURAL GAS SECTOR: NEW SOURCE PERFORMANCE STANDARDS AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS REVIEWS", Dkt No. EPA-HQ-OAR-2010-0505-4590 (Aug. 16, 2012), available at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4590>; TEXAS OIL & GAS ASSOCIATION PETITION FOR RECONSIDERATION AND REQUEST FOR STAY, Dkt No. EPA-HQ-OAR-2010-0505-4586 (Oct. 15, 2012), available at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4586>. These petitions requested various clarifications and additional exemptions, but none attack the basic requirements for green completions and flaring.

52. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 77 Fed. Reg. at 49,514.

sions.⁵³ As described below, NO_x emission reductions from shale gas and oil drilling operations may become a major issue as states begin searching for ways to reduce ground-level ozone.

B. Emissions of Ozone Precursors

In 2012, Wyoming's Upper Green River Basin, Sublette County, and parts of Lincoln and Sweetwater Counties were designated as not attaining the eight-hour National Ambient Air Quality Standards ("NAAQS") for ground-level ozone.⁵⁴ Ozone non-attainment is generally associated with industrial urban areas with high vehicle traffic, making high ozone levels in rural Wyoming a surprise. Similarly high ozone concentrations were found in Utah and attributed to oil and gas development.⁵⁵ Since the Clean Air Act generally requires that states design plans for implementing regulations that will allow for compliance with ambient air quality standards,⁵⁶ oil and gas operations may be facing more stringent state emission regulations. Studies on how to reduce ozone concentrations are already underway. Wyoming's Department of Environmental Quality formed an advisory committee to implement additional controls to reduce wintertime ozone levels.⁵⁷ Other studies are examining ozone levels in Utah's Uinta Basin⁵⁸ and Pennsylvania.⁵⁹ The Ozone Transport Commission, a consortium of Mid-Atlantic and Northeast state environ-

53. *Id.* at 49,493.

54. See Letter from Lisa P. Jackson, EPA, to Matt Mead, Governor of Wyo. (Apr. 30, 2012), available at http://deq.state.wy.us/aqd/downloads/Nonattainmentletter4_30_12.pdf; 77 Fed. Reg. 30,088, 30,157–58 (May 21, 2012); see generally *Ozone Nonattainment Information*, WYO. DEP'T OF ENV'T'L QUALITY, <http://deq.state.wy.us/aqd/Ozone%20Nonattainment%20Information.asp> (last visited Jan. 30, 2013). The NAAQS establish maximum acceptable concentrations for what are known as "criteria pollutants" including oxides of nitrogen, carbon monoxide, sulfur dioxide, particulate matter with an aerodynamic diameter less than or equal to 10 microns (also known as "PM10"), or with an aerodynamic diameter less than or equal to 2.5 microns (known as "PM2.5"), ozone, and lead. See Proposed Rule, National Ambient Air Quality Standards for Ozone, 75 Fed. Reg. 2,938, 2,941 (Jan. 19, 2010) (to be codified at 40 C.F.R. pt. 50).

55. See UTAH DEP'T OF ENV'T'L QUALITY, RURAL AIR QUALITY AND OIL/GAS DEVELOPMENT IN UTAH FACT SHEET, (June 2010), available at [http://www.deq.utah.gov/locations/uintahbasin/docs/2012/Feb/June 2010- Air_Issues.pdf](http://www.deq.utah.gov/locations/uintahbasin/docs/2012/Feb/June%2010-Air_Issues.pdf).

56. See 42 U.S.C. § 7410(a) (2006). If states fail to timely submit implementation plans ("SIPs") for NAAQS compliance, or if those plans are not approved by the EPA Administrator, the Administrator must issue a Federal Implementation Plan directly regulating the sources of air pollution that are causing the state's non-attainment status. *Id.* § 7410(c).

57. See WYOMING DEP'T OF ENV'T'L QUALITY, AIR QUALITY DIVISION OZONE TECHNICAL ADVISORY GROUP TRANSITION TO OZONE TECHNICAL FORUM (Aug. 2011) (formation of the Ozone Technical Forum to concentrate on wintertime ozone levels), available at http://deq.state.wy.us/aqd/Technical%20Documents%20-%20Ozone/TAG_TransitionOTF_Aug2011.pdf.

58. *Utah's Environment: 2012: Cleaner Air: Uintah Basin: Three-State Pilot Project*, UTAH DEP'T OF ENV'T'L QUALITY, <http://www.deq.utah.gov/locations/uintahbasin/2012study.htm> (last visited Jan. 30, 2013), (discussing interim findings of Uintah Basin Impact Mitigation Special Service District's 2011–2012 winter ozone study and planning for 2012–2013 winter ozone study).

59. Pa. Dep't of Env't'l Quality, *Long-Term Ambient Air Monitoring Project Near Permanent Marcellus Shale Gas Facilities Protocol* (July 23, 2012), available at http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Long-Term_Marcellus_Ambient_Air_Monitoring_Project-Protocol_for_Web_2012-07-23.pdf.

mental agencies, issued a draft technical study advising states on ways to potentially reduce ozone-forming emissions from the oil and gas sector.⁶⁰

Both VOCs and NO_x are precursors to ground-level ozone; reducing emissions of these pollutants is necessary to reduce ozone concentrations.⁶¹ EPA's decision not to regulate NO_x emissions in the revised Oil & Gas NSPS means that states must now determine the relative importance of each precursor to ground-level ozone formation in their areas. Yet, knowing the degree of VOC or NO_x emission contributions to ground-level ozone can be difficult because ozone monitoring stations are typically concentrated around urban areas, not the rural areas where oil and gas wells are located in many states.⁶² A number of environmental groups petitioned the EPA Administrator to require oil and gas operators to install additional ozone monitoring stations under section 114 of the Clean Air Act.⁶³ One of the controversies to come will be the possible installation of new monitoring stations, their number and locations, and the method of potentially implementing such a program—such as federal grants to state agencies, requiring ozone monitoring as part of a Clean Air Act settlement agreement, or a broad mandate imposed on all oil and gas owners and operators under section 114 of the Clean Air Act.⁶⁴

While additional monitoring data could be useful in gauging compliance with the ozone NAAQS, and to determine how to either return areas to attainment or avoid a non-attainment designation, it is not entirely clear what additional regulation of hydraulic fracturing operations could be required. EPA estimated that the Oil & Gas NSPS revisions will reduce VOC emissions by 190,000 tons per year.⁶⁵ This will be a dramatic reduction in VOCs from current baseline estimates.⁶⁶ With regulations already requiring green completions and flaring, there will be limited

60. Ozone Transport Comm'n, Draft, Technical Information Oil and Gas Sector, Significant Stationary Sources of NO_x Emissions (on file with author).

61. See, e.g., National Ambient Air Quality Standards for Ozone, 75 Fed. Reg. 2,938, 2,941 (proposed Jan. 19, 2010) (to be codified at 40 C.F.R. pt. 50).

62. Approval and Promulgation of Implementation Plans; Texas; Revisions to General Air Quality Rules and the Mass Emissions Cap and Trade Program, 74 Fed. Reg. 34,525, 34,530 (proposed July 16, 2009) (to be codified at 40 C.F.R. pt. 52) (footnote omitted) (stating that "many large mid-western and western states have one or no non-urban monitors"). For a map of existing ozone monitoring stations, see *Ozone*, EPA, <http://www.epa.gov/airtrends/ozone.html> (last visited Jan. 30, 2013).

63. CAL. KIDS IAQ, ET AL., PETITION TO THE U.S. ENVIRONMENTAL PROTECTION AGENCY TO 1) PROMPTLY REQUIRE OIL AND GAS OWNERS AND OPERATORS TO MONITOR FOR OZONE AND 2) TO ISSUE CONTROL TECHNIQUES GUIDELINES FOR OIL AND NATURAL GAS OPERATIONS IN NON-ATTAINMENT AREAS (Dec. 19, 2012), available at http://www.edf.org/sites/default/files/Ozone_Monitoring_and_Oil_and_Natural_Gas-Petition.pdf.

64. See generally 42 U.S.C. § 7414(a)(1) (2006).

65. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,492 (Aug. 16, 2012) (to be codified at 40 C.F.R. pt. 60, 63).

66. Even if one credits EPA's baseline estimate of 505,879 tons per year of VOC emissions from production, exploratory, and developmental gas and oil well completions and recompletions, TSD at 4-13, this is an approximate thirty-eight percent reduction in VOC emissions. EPA, OIL AND NATURAL GAS SECTOR: STANDARDS OF PERFORMANCE FOR CRUDE OIL AND NATURAL GAS PROD., TRANSMISSION, AND DISTRIBUTION 2-2 (July 2011), available at <http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf>. As discussed below, however, EPA's assumptions grossly overestimate the amount of emissions vented to the atmosphere from well completions and re-completions. See *infra* at note 239 and accompanying text (making VOC reductions from the Oil & Gas NSPS even larger as a proportion of existing emissions).

options for further VOC reductions. Environmental groups, as part of their petition for additional ozone monitoring, requested that the EPA Administrator issue VOC Control Technique Guidelines for oil and gas operations located in ozone non-attainment areas.⁶⁷ Among those suggested for hydraulically fractured well sites were fugitive emission leak detection and repair programs; stringent VOC emission controls for area source glycol dehydrators (i.e., those emitting less than five tons per year) and existing condensate, crude oil, and produced water tanks; VOC controls for pits that receive flowback water; requiring plunger lift systems or closed loop systems during maintenance activities known as liquids unloading; and limiting the use of flaring.⁶⁸ Evaluating such control strategies, however, would be a major undertaking. Aside from the questions about whether these controls could be cost effective after implementing the revised Oil & Gas NSPS,⁶⁹ at least one of these suggestions, limits on flaring, is contrary to the Oil & Gas NSPS requirements.⁷⁰ Additional methods to reduce VOCs may be needed; however, those methods are more likely to come from evolving industry practices or agreements with state regulatory agencies, not EPA.

Nitrogen oxide emissions from oil and gas wells are largely emitted as exhaust from engines⁷¹ and are already regulated by EPA New Source Performance Standards.⁷² EPA declined to tighten these standards in the Oil & Gas NSPS.⁷³ Therefore, states would have to implement new regulations or craft agreements with well developers to find additional NO_x reductions. Future NO_x regulations may rely on new practices being developed by the industry right now. Several companies are experimenting with methods for dramatically reducing NO_x emissions in order to cut completion costs. Toward the end of 2012 and the beginning of 2013, diesel fuel was averaging approximately \$3.91 per gallon.⁷⁴ Encana Corporation estimated that the entire industry used 1.2 billion gallons of diesel fuel for hydraulic fracturing in 2012, costing oil and gas developers billions of dollars each year.⁷⁵ In response to this, wellfield services company Baker Hughes recently con-

67. See 42 U.S.C. § 7511b (1997) (allowing new Control Technique Guidelines for VOC sources “as the Administrator deems necessary”).

68. CAL. KIDS IAQ, ET AL., *supra* note 63, at 28–29.

69. See EPA, OFFICE OF AIR AND RADIATION, THE BENEFITS AND COSTS OF THE CLEAN AIR ACT FROM 1990 TO 2020 3-6-307 (Mar. 2011), available at www.epa.gov/air/sect812/feb11/summaryreport.pdf (“Controls more costly than \$15,000 per ton” of ozone precursor removed “may not be cost effective.”).

70. See, e.g., 40 C.F.R. § 63.771(d)(4)(i) (2012) (requiring flare to “be operating at all times when gases, vapors, and fumes are vented from the HAP emissions units”).

71. See EPA OFFICE OF COMPLIANCE, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY 38 (Oct. 2000), available at <http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oilgas.pdf>.

72. See 40 C.F.R. § 60.4204 (2012) (NOX emission standards for compression ignition internal combustion engines); *id.* § 60.4233 (NOX emission standards for spark ignition combustion engines).

73. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,514 (Aug. 16, 2012).

74. U.S. Energy Info. Admin., *Gasoline and Diesel Fuel Update*, EIA.GOV (Jan. 7, 2013), <http://www.eia.gov/petroleum/gasdiesel/>.

75. Estimates on the amount of diesel and the average cost of diesel vary. See *Apache Would Replace Diesel with Gas on Frac Jobs*, OIL & GAS J. (Jan. 21, 2013), <http://www.ogj.com/articles/print/volume-111/issue-1b/general-interest/apache-would-replace-diesel-with-gas.html> (estimating that industry spent \$2.38 billion on diesel at an average cost of \$3.40 per gallon); Zain Shauk, *Fracking with Natural Gas to Trim Fuel Costs 40%*, FUELFIX.COM (Jan. 7, 2013), <http://fuelfix.com>

verted some of its energy-intensive portable pumps to use a mix of diesel fuel and natural gas.⁷⁶ These “bifuel” pumps can reduce diesel usage, and their accompanying emissions—including NO_x and VOCs—by up to sixty-five percent.⁷⁷ The company reported that the bifuel pumps were successfully used for hydraulically fracturing a well in the Eagle Ford Shale play, and the company expects to deploy more of them in the future.⁷⁸ Apache Corporation, partnering with Halliburton, Schlumberger, and Caterpillar, announced a similar move, hydraulically fracturing a well in January 2013 with twelve bifuel engines.⁷⁹ The company reported a forty percent savings on fuel and expects that its average cost will decline from \$123,000 per job to approximately \$75,000.⁸⁰ And Halliburton recently debuted its SandCastle process, a new method of injecting sand into hydraulic fracturing fluid using gravity and solar panels instead of diesel engines.⁸¹ As an additional emission savings, tapping gas from a nearby wellhead would reduce tanker truck emissions as less diesel fuel must be hauled out to the site.⁸² Given the financial incentives to reduce the use of diesel fuels, and the rapid adoptions of alternatives to diesel engines, NO_x and VOC emissions will likely decline even as federal and state governments work to establish a baseline for these emissions.⁸³ These alternatives, however, may become industry standards that help return some areas to attainment with the ozone NAAQS.

C. Air Emissions from Oil and Gas Activities on Federal Lands in Non-Attainment Areas

The regulation of hydraulic fracturing, and any related air emissions, will often fall to state agencies, both as a matter of state oil and gas law and under the Clean Air Act’s cooperative federalism scheme.⁸⁴ Yet, there is significant oil and gas development outside of state jurisdictions.⁸⁵ The federal government, through

blog/2013/01/07/fracking-with-natural-gas-to-trim-fuel-costs-40/ (estimating that the industry used 700 million gallons of diesel in 2012 for a total industry cost of \$2.38 billion).

76. Baker Hughes Press Release, Baker Hughes Converts Fleet of Hydraulic Fracturing Units to Bifuel (Nov. 26, 2012), <http://www.bakerhughes.com/news-and-media/media-center/press-releases/monday-november-26-2012-baker-hughes-converts-fleet-of-hydraulic-fracturing-units-to-bifuel>.

77. *Id.*

78. *Id.*

79. Zain Shauk, *Fracking with Natural Gas to Trim Fuel Costs 40%*, FUELFIX.COM (Jan. 7, 2013), <http://fuelfix.com/blog/2013/01/07/fracking-with-natural-gas-to-trim-fuel-costs-40/>.

80. *Id.*

81. David Wethe, *Fracking Companies Embrace Solar to Cut Carbon Emissions: Energy*, BLOOMBERG NEWS (Nov. 29, 2012), <http://www.bloomberg.com/news/2012-11-29/fracking-companies-embrace-solar-to-cut-carbon-emissions-energy.html>.

82. *See* Shauk, *supra* note 75.

83. *See, e.g.*, Office of Sci., *NO_x and VOC Emission Trends*, N.J. DEP’T OF ENVTL. PROT., 1-2 (Sept. 2011), <http://www.nj.gov/dep/dsr/trends/pdfs/nox-voc.pdf> (discussing New Jersey’s adoption of standards for NO_x and VOC emissions).

84. *See Summary of the Clean Air Act*, EPA, <http://www.epa.gov/regulations/laws/caa.html> (last visited Feb. 24, 2013).

85. *See* U.S. Dep’t of Interior, *The Bureau of Land Management: Who We Are, What We Do*, BUREAU OF LAND MGMT, http://www.blm.gov/wo/st/en/info/About_BLM.html (last visited Mar. 20, 2013).

the U.S. Bureau of Land Management (“BLM”), manages 245 million surface acres of land and 700 million acres of mineral rights.⁸⁶ BLM will frequently open these federal lands to oil and gas leasing as part of area resource management plans,⁸⁷ subject to the National Environmental Policy Act (“NEPA”), among other statutory restrictions.⁸⁸ Under NEPA, the lead federal agency will perform an air quality and air quality-related values analysis when leasing federal land for oil and gas development.⁸⁹ Additionally, no federal agency, including BLM, may “engage in, support in any way or provide financial assistance for, license or permit, or approve, any activity which does not conform to an implementation plan” under the Clean Air Act.⁹⁰ Put simply, this provision, known as the Conformity Rule, prohibits federal agencies from authorizing any activity that will cause or contribute to NAAQS violations.⁹¹

Under this combined review process, BLM must perform an Environmental Assessment, and possibly issue an Environmental Impact Statement, for resource management plans involving oil and gas leases, and if the action is in a non-attainment area, then BLM must also perform a Conformity Evaluation. Under NEPA, a BLM Environmental Impact Statement, if required, would examine potential “near-field” and “far-field” impacts from hazardous air pollutants, ozone precursors, and other criteria pollutants.⁹² These would include potential impacts on visibility in Class I areas, cancer and non-cancer health effects from both acute and long-term exposure to emissions, and compliance with all applicable NAAQS.⁹³ The Conformity Rule, however, adds a much more detailed layer of air emissions analysis. In addition to the NEPA analysis, BLM would have to determine if its

86. *Id.*

87. Resource Management Plans are developed to guide individual land management actions in a way that balances the multiple uses to which federal lands are subject, such as recreation, grazing, timbering, and oil and gas production. *See generally* Resource Mgmt. Planning, 43 C.F.R. § 1610 (2012) (BLM’s resource management plan regulations). Under the Federal Land Policy and Management Act of 1976, federal lands must be managed “in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resources, and archeological values.” 43 U.S.C. § 1701(a)(8) (2012).

88. *See, e.g.*, *New Mexico ex rel. Richardson v. BLM*, 565 F.3d 683, 689-691 (10th Cir. 2009) (describing resource management plan process that included oil and gas leasing of public lands and its operation under NEPA). BLM resource management plans may be subject to the requirements of several other statutes, including the Endangered Species Act, Federal Land Policy and Management Act, the National Historic Preservation Act, the Native American Graves Protection and Repatriation Act, the Federal Onshore Oil and Gas Leasing Reform Act of 1987, and several others. *See* Consistency Requirements, C.F.R. § 1610.3-2 (2012).

89. *See* Memorandum of Understanding Among the U.S. Dep’t of Agric., U.S. Dep’t of the Interior, and the EPA, Regarding Air Quality Analyses and Mitigation for Federal Oil and Gas Decisions Through the Nat’l Env’tl. Policy Act Process 8 (June 23, 2011), *available at* <http://www.epa.gov/compliance/resources/policies/nepa/air-quality-analyses-mou-2011.pdf> (describing collaborative performance of air quality and air quality related value analyses for federal oil and gas leasing decisions).

90. 42 U.S.C. § 7506 (2012).

91. These actions include anything that will delay attainment of a NAAQS or required interim milestone, or exacerbate existing violations of the NAAQS. *See id.* §§ 7516(c)(1)(A)–(B). EPA promulgated implementing regulations, known as the General Conformity Rule. 40 C.F.R. § 93.150 (2012).

92. *See* BUREAU OF LAND MGMT., OIL AND GAS DEVELOPMENTS DRAFT RMPA/EIS, APPENDIX F: AIR QUALITY IMPACTS, 8 (Aug. 30, 2012), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/co/programs/land_use_planning/rmp/white_river/documents/rmpa3.Par.22594.File.dat/13_WRFO_RMPA-EIS_Appendix%20F_Aug2012.pdf.

93. *Id.*

action (leasing federal land for oil and gas development) would result in reasonably foreseeable direct and indirect criteria pollutant emissions (or precursor emissions) in excess of de minimis levels for a non-attainment area.⁹⁴ In this review, BLM bears a burden of demonstrating that leasing will not cause new violations of the NAAQS.⁹⁵ This conformity demonstration can be made through one of several avenues: (1) demonstrating that the direct and indirect emissions are already accounted for in the applicable state implementation plan; (2) showing that they will be offset through enforceable emissions reductions to ensure there is no net increase of the criteria pollutant; or (3) conducting air quality modeling demonstrating that the direct and indirect emissions attributable to the federal action will not cause or contribute to new violations of the NAAQS (or lead to increases in the frequency or severity of existing violations).⁹⁶ These Conformity Evaluations are subject to public notice and comment, and they are often combined with the NEPA public review process.⁹⁷

Although BLM has previously undertaken NEPA reviews of oil and gas leasing on federal lands, a combined NEPA review and General Conformity Rule assessment for oil and gas projects on large western lands in non-attainment areas is relatively new. This could lead to two major controversies in the next few years. The first could be BLM's emission estimates for oil and gas leases on federal lands in non-attainment areas. In performing a Conformity Evaluation, BLM must consider all direct and indirect emissions from its decision to open federal lands to leasing.⁹⁸ This requires an estimate of both the number of wells that would be drilled and the emissions from each well.⁹⁹ For hydraulic fracturing, most VOC and NO_x emissions take place during the drilling and completion stage, after which there are comparatively few emissions from the wells.¹⁰⁰ It is possible that BLM could require a staged process where a relatively small set of wells are drilled and completed during any given time frame. Such staging could keep emissions below the de minimis level and preclude a Conformity Evaluation.¹⁰¹ Yet, this is complicated by the fact that EPA has a penchant for overestimating emissions from hydraulic fracturing operations.¹⁰² The debate as to BLM's ability to stagger well drilling and completions, and the emissions estimates it uses, could spill into court. Second, there is evidence that ozone non-attainment results largely from atmos-

94. See 40 C.F.R. § 93.153 (detailing factors for applicability of the General Conformity Rule).

95. *Id.* § 93.158(c).

96. *Id.* § 93.158(a).

97. *Id.* § 93.155-156.

98. *Id.* § 53.158(a)(2). This language is similar to that in the Council on Environmental Quality's regulations requiring federal agencies to consider both the direct and indirect "effects" of agency actions under an Environmental Impact Statement. *Id.* § 1502.16(a), (b).

99. It would only be logical to count both the wells and their emissions. See *id.*

100. See generally EPA, REDUCED EMISSIONS COMPLETIONS FOR HYDRAULICALLY FRACTURED NATURAL GAS WELLS (2011), available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.

101. *Id.*

102. See Gayathri Vaidyanathan, *The Entire Natural Gas System' Is Driving Methane Emissions – MIT study*, EENEWS.NET (Nov. 28, 2012), <http://eenews.net/public/energywire/2012/11/28/1>.

pheric inversions during the winter months.¹⁰³ This means that legal limitations on oil and gas ozone precursor emissions during the winter months could potentially lead to a conformity determination.¹⁰⁴ Wyoming, for example, has already implemented an Ozone Contingency Plan where oil and gas companies take measures to reduce ozone precursor emission whenever the Department of Environmental Quality declares an “Ozone Action Day.”¹⁰⁵ States and the industry may have to get creative, and potentially restrict oil and gas activities during certain times of the year, to avoid a determination that new operations on federal lands would cause or contribute to a NAAQS violation. Many of these questions may be resolved over the next few years in litigation.

III. AGGREGATION

The oil and gas industry is likely to be involved in several years of conflict regarding the aggregation of emission sources. In Clean Air Act parlance, “aggregation” refers to the combination of several different emission sources into a single “major source” for permitting purposes, either under the Prevention of Significant Deterioration (“PSD”) or Title V programs.¹⁰⁶ The concept of aggregation dates back to the mid-1970s, as EPA grappled to define a “source” under early PSD regulations. When the D.C. Circuit struck down the “source” definition in 1979, it advised that “EPA should devise regulatory definitions of the” statutory “terms ‘structure,’ ‘building,’ ‘facility,’ and ‘installation’ to provide for the aggregation, where appropriate, of industrial activities according to considerations such as proximity and ownership.”¹⁰⁷

After *Alabama Power*, EPA adopted regulations defining a “major source” for the PSD program.¹⁰⁸ First a “major source” must be a “stationary source,” defined as “any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant.”¹⁰⁹ The term “[b]uilding, structure, facility, or installation” is then defined as “all of the pollutant-emitting activities” that meet all of the following criteria: they are (1) located on one or more contiguous or adjacent properties; (2) under common ownership or control; and (3) belonging to a single major indus-

103. See Air Quality Div., The Wyo. Dep’t of Env’tl. Quality, Technical Support Document I For Recommended 8-Hour Ozone Designation for the Upper Green River Basin, WY 31, (Mar. 26, 2009), available at http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf.

104. EPA, GENERAL CONFORMITY TRAINING MODULE 36 (July 22, 2011), available at http://www.epa.gov/oar/genconform/training/files/General_Conformity_Training_Manual.pdf. Note that such legal limitations would have to be specified in a revision to the state’s implementation plan that would establish an emissions budget to reduce overall emissions. See 40 C.F.R. § 93.158(a)(5)(B) (2012).

105. Memorandum from Brett Davis, Wyo. DEQ, Air Quality Div. Planning Section, to Ozone Contingency Plan Participants (Oct. 14, 2011), available at <http://deq.state.wy.us/aqd/Ozone/2012%20OCP%20Instruction%20Memo.pdf>.

106. See 42 U.S.C. § 7661a(a) (2012) (requiring a “major source” to obtain a Title V permit in order to operate); 40 C.F.R. § 52.21(b)(5) (2012) (defining a “stationary source” subject to PSD). These definitions are virtually identical.

107. *Ala. Power v. Costle*, 636 F.2d 323, 397 (D.C. Cir. 1979).

108. Requirements for Preparation, Adopting, and Submittal of Implementation Plans; Approval and Promulgating of Implementation Plans, 45 Fed. Reg. 52,676 (Aug. 7, 1980) (codified at 40 C.F.R. §§ 51.24, 52.21, 52.24, & 51.18(j)).

109. 40 C.F.R. § 52.21(b)(5) (2012).

trial grouping.¹¹⁰ EPA explained that these criteria should be applied to “approximate a common sense notion of ‘plant’” and avoid “group[ing] activities that ordinarily would be considered separate.”¹¹¹ Thus, more than one emission source (“all of the pollutant-emitting activities”) may be aggregated into a single stationary source for PSD permitting purposes. The 1990 Clean Air Act Amendments included these three criteria in defining a “major source” for Title V permitting purposes.¹¹² The practical utility of this test is fairly obvious. A source owner or operator would not be able to escape permitting requirements by artificially separating two or more related emission sources by merely constructing them on distant and opposite ends of their property or paving a road between them.

Despite promising to be restrained by common sense, EPA gradually interpreted the aggregation provisions in a way that contested that boundary. In a series of letters, colloquially known as “source determinations,” EPA regional offices advised both individual companies and state permitting agencies whether it believed that separate emission sources should be aggregated into a single “major source.”¹¹³ The criteria of common ownership or control and common industrial classifications were rarely contentious. Instead, source determinations frequently required disparate emission sources to be aggregated across considerable distances under the justification that they were “contiguous or adjacent.” For example, EPA Region VIII determined that the Great Salt Lake Minerals’ processing facility was “contiguous or adjacent” to a pump station 21.5 miles away and separated by the Great Salt Lake.¹¹⁴ Other “contiguous or adjacent” emission points included (1) a soda processing plant and a mine, forty-four miles distant;¹¹⁵ (2) a brewery and a farm, six miles apart;¹¹⁶ (3) a steel mill and a coke plant, separated by 3.7 miles and Lake Calumet, a landfill, and the Little Calumet River;¹¹⁷ and (4) a wood recycling center and a combined heat and power boiler three miles away.¹¹⁸

No person could seriously claim that any of these points, miles apart from each other, were “contiguous or adjacent” (at least if asked to walk between them), but EPA determined that physical proximity was of little relevance in determining whether emission sources were contiguous or adjacent. Over the years, EPA deter-

110. 40 C.F.R. § 52.21(b)(6).

111. 45 Fed. Reg. 52,676, 52,695 (Aug. 7, 1980).

112. 42 U.S.C. § 7661(2) (2006).

113. Source determinations are not subject to public notice and comment and are considered by EPA to be informative but non-binding. *See, e.g.*, Letter from Cheryle L. Newton, EPA Region V, to Scott Huber, Summit Petroleum Corporation (Oct. 18, 2010), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/singler5.pdf> (“Neither the final determination nor the specific facts considered are binding on other source determinations for pollutant-emitting activities with different fact specific circumstances.”).

114. Letter from Richard Long, EPA Region VIII, to Lynn R. Menlove, Utah Dep’t of Env’tl Quality (Aug. 8, 1997), available at <http://www.epa.gov/region07/air/nsr/nsrmemos/utl-at1.pdf>.

115. Letter from Richard Long, EPA Region VIII, to Dennis Myers, Colorado Air Pollution Control Div. (Apr. 20, 1999), available at <http://www.epa.gov/region07/air/nsr/nsrmemos/amersoda.pdf>.

116. Memorandum from Robert G. Kellam, EPA OAQPS, to Richard Long, EPA Region VIII (Aug. 27, 1996), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/abnt.pdf>.

117. Letter from Cheryl L. Newton, EPA Region V, to Donald Sutton, Illinois EPA (Mar. 13, 1998), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/acme.pdf>.

118. Letter from Pamela Blakley, EPA Region V, to Don Smith, Minn. Pollution Control Agency (Mar. 23, 2010), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/single.pdf>.

mined that the “functional interrelationships” between two emission sources was the key consideration in its source determinations.¹¹⁹ EPA informally defined functional interrelationships to involve the following criteria: (1) whether the locations of two facilities were selected to enable integration; (2) whether there is any physical link or transportation of materials between the two emission sources; (3) whether workers travel between the two emission sources; or (4) whether one facility will produce an intermediate product that requires further processing by the other.¹²⁰ As applied by EPA regional offices, this entails a case-by-case review with no single factor appearing to outweigh the others.¹²¹ EPA regional offices therefore have substantial flexibility to find “functional interrelationships” on rather thin reeds. For example, EPA Region V affirmed that a wood recycling center and a combined heat and power boiler, three miles apart, were “contiguous or adjacent” simply because the boiler received truckloads of wood waste as fuel via public roads.¹²²

Of course, one will look in vain for any mention of functional interrelationships in the Clean Air Act or EPA’s regulations.¹²³ The only place, outside of its source determinations where EPA discussed the concept was in the preamble to its final aggregation regulations. There, EPA “asked for comment on whether factors other than proximity and control, such as the functional relationship of one activity to another, should be used.”¹²⁴ Instead of adopting the “functional relationship” analysis, however, EPA explicitly rejected it.¹²⁵ The Agency found that applying such a principle “would be highly subjective,” and would “have made administration of the definition substantially more difficult, since any attempt to assess those interrelationships would have embroiled the Agency in numerous, fine-grained analyses.”¹²⁶ Such a view would also “severely strain the boundaries of even the most elastic of the four terms ‘building,’ ‘structure,’ ‘facility’ and ‘installation.’”¹²⁷

A. Aggregation for Oil and Gas Facilities

The “functional interrelationships” test poses especially sticky problems for oil and gas wells and processing facilities. Recognizing this, EPA’s Office of Air and Radiation issued a guidance memorandum instructing regional offices to rely on the actual regulatory criteria for aggregation, with a special emphasis on physi-

119. See, e.g., Letter from Winston A. Smith, EPA Region IV, to Randy C. Poole, Mecklenburg County Env’tl Protection, at 6 (May 19, 1999), available at <http://www.epa.gov/region07/air/nsr/nsrmemos/we1999.pdf> (“In most of the EPA documents we reviewed, the key factor in deciding that separate facilities should be considered as one source was the facilities were interdependent or linked in some sense.”).

120. Memorandum from Douglas E. Hardesty, EPA Region X, to Robert R. Robichaud, EPA Region X, at 5–6 (Aug. 21, 2001), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/20010821.pdf>.

121. Memorandum from Robert G. Kellum, EPA OAQPS, to Richard Long, EPA Region VIII, at 3 (Aug. 27, 1996), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/abnt.pdf>.

122. Letter from Pamela Blakley, EPA Region V, to Don Smith, Minn. Pollution Control Agency, at 3 (Mar. 23, 2010), available at <http://www.epa.gov/region7/air/nsr/nsrmemos/single.pdf>.

123. Requirements for Preparation, Adopting, and Submittal of Implementation Plans; Approval and Promulgating of Implementation Plans, 45 Fed. Reg. 52,694 (Aug. 7, 1980).

124. *Id.*

125. *Id.* at 52,695.

126. *Id.*

127. *Id.*

cal proximity instead of interdependence, in making aggregation determinations for oil and gas emission sources.¹²⁸ The so-called Wehrum Memo noted that “well sites can be located hundreds of miles from” a connected natural gas processing plant and “some oil and gas operations (e.g., a production field) can cover many square miles.”¹²⁹ The separation of surface property rights and subsurface mineral rights also complicates the question of what is “contiguous or adjacent” as oil and gas companies typically only control the surface area necessary for well pads and related equipment.¹³⁰ This means that a well field will include small and scattered islands of land controlled by the company amidst a sea of property owned and controlled by third parties. Wells are, by necessity, connected via gathering pipelines to processing facilities, but actual interdependence can vary from field to field. Because of this, the Wehrum Memo harkened back to EPA’s preamble warning and noted that applying the interdependence test to oil and gas operations “would embroil the Agency in precisely the fine-grained analysis we intended to avoid” and “potentially lead to results which do not adhere to the common sense notion of a plant.”¹³¹ The memo advised that permitting authorities “can find that two pollutant-emitting activities are separate sources when they are located far apart, irrespective of the presence of physical connections and operational dependence between the sites.”¹³²

EPA’s respect for physical proximity was short-lived. A September 22, 2009 memorandum by Assistant Administrator Gina McCarthy withdrew the Wehrum Memo.¹³³ In a puzzling passage, the McCarthy Memo stated that EPA is “instead re-emphasizing the fundamental criteria for making source determinations.”¹³⁴ Although this was the purpose of the Wehrum Memo, the McCarthy Memo disclaimed any emphasis on physical proximity in determining whether emission sources were contiguous or adjacent.¹³⁵ Curiously, the McCarthy Memo only indirectly recalled the interdependence test from its short hiatus as it is never mentioned by name or even described. In fact, the McCarthy Memo’s brief summary of the aggregation

128. Memorandum from William L. Wehrum, EPA, to Regional Administrators I-X, (Jan. 12, 2007) [hereinafter Wehrum Memo] available at https://docs.google.com/viewer?a=v&q=cache:25lmDPe4DIgJ:www.eenews.net/public/25/12769/features/documents/2009/10/13/document_pm_02.pdf+wehrum+memo+source+determination+for+oil+and+gas+pdf&hl=en&gl=us&pid=bl&srcid=ADGEESjzS3nzKqt2QyMzVd_lr2oVUnq1m6_ET5LaP4K1_wZqV4j_1_sUSAjDegYHSBISdXpIQw8gKV6hOE8u5pPWl66P3TlkyPa5CD9Yh__h86BuOtCWUafMnObTclC_13ZmBOyElw&sig=AHIEtbQKGXOuV1fd-Kq1pAs8JKH-2V6d-w.

129. *Id.* at 2.

130. *Id.*

131. *Id.* at 3. Note also that in this preamble, EPA also “confirm[ed] that it d[id] not intend ‘source’ to encompass activities that would be many miles apart along a long-line operation.” Requirements for Preparation, Adopting, and Submittal of Implementation Plans; Approval and Promulgating of Implementation Plans, 45 Fed. Reg. at 52,695. This would appear to preclude stringing several distant emission sources together simply because they are connected by a pipeline.

132. Wehrum Memo, *supra* note 128, at 3.

133. Memorandum from Gina McCarthy, to Regional Administrators Regions I-X, “Withdrawal of Source Determinations for Oil and Gas Industries, U.S. Env’tl. Prot. Agency” (Sept. 22, 2009), <http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf>, at 1.

134. *Id.*

135. *Id.*

regulations and their preamble would seem to foreclose the interdependence test. However, the McCarthy Memo advised regional offices to rely on EPA's database of source determinations—the collection of documents where the interdependence test lived out its cloistered existence—as they “illustrate the kind of reasoned decision-making that is necessary to justify adequately a permitting authority's source determination decision.”¹³⁶

B. The *Summit Petroleum* Decision

The interdependence test operated for decades as a substitute for the “contiguous or adjacent” criterion for aggregation until a small oil and gas company in Michigan filed a petition for review with the U.S. Court of Appeals for the Sixth Circuit. Summit Petroleum Corporation appealed an EPA Region V source determination finding that its natural gas sweetening plant must be aggregated with its approximately 100 sour gas production wells and flares into a single “major source” under Title V.¹³⁷ The gas wells and flares were spread over forty-three square miles and were located anywhere from 500 feet to eight miles away from the sweetening plant.¹³⁸ Third parties owned the properties between the wells, and none of them shared a common boundary with the sweetening plant.¹³⁹ Only by aggregating these sources together could their cumulative emissions top 100 tons per year, vaulting the “source” over the major source threshold.¹⁴⁰

Beginning its journey in January 2005, Summit and the Michigan Department of Environmental Quality requested EPA Region V to issue a source determination as to whether its sweetening of plant, sour gas wells, and flares required a Title V permit.¹⁴¹ Summit opposed aggregation, noting that its wells and flares were “located at great distances from its production facility on entirely different tracts, leases and surface sites.”¹⁴² After rounds of additional submissions to the region, EPA finally concluded in October 2010 that Summit's sweetening plant, gas wells, and flares must be aggregated and required a Title V permit, citing the “degree of interdependence between them.”¹⁴³ Summit petitioned the Sixth Circuit for review of the source determination, on the sole question of whether its gas sweetening plant was “adjacent” to its wells and flares.¹⁴⁴

The court's decision was a true rarity in administrative law, striking down a long-standing agency interpretation of its own regulations by finding that the term “adjacent” was unambiguous.¹⁴⁵ Relying on the ordinary dictionary definition of “adjacent,” as well as its etymology, the Sixth Circuit found that the word *must* involve the physical proximity of two or more points.¹⁴⁶ The EPA begged that “dic-

136. *Id.* at 2.

137. *Summit Petroleum Corp. v. EPA*, 690 F.3d 733, 736 (6th Cir. 2012), *reh'g denied* 2012 U.S. App. LEXIS 23988 (Oct. 29, 2012).

138. *Id.* at 735–36.

139. *Id.* at 736.

140. *Id.*

141. *Id.* at 737.

142. *Id.* (internal quotations omitted).

143. *Id.* at 738–40.

144. *Id.* at 741.

145. *Id.*

146. *Id.* at 741–43.

tionaries provide an incomplete definition of ‘adjacent,’ and that the functional interrelationship of two facilities *must* be considered because physical distance is meaningless without context.”¹⁴⁷ The court responded with two points. The first was that no dictionary definition suggested that the word “adjacent” connotes any assessment of a relationship between two points other than distance.¹⁴⁸ The second was that, although context is important (“it is certainly correct that two states could be adjacent to one another in the context of a country, just as two houses could be adjacent in the context of a neighborhood”), this context does not include “the *purpose* for which two activities exist in order to consider whether they are adjacent to one another.”¹⁴⁹ In short, the court concluded that two points will either be adjacent or distant regardless of what goes on at those points.¹⁵⁰ Without finding that the word “adjacent” is ambiguous, or at least not ambiguous in the fashion that the EPA proposed, the Sixth Circuit owed no deference to the Agency’s interpretation. Without that deference, the court found the EPA’s interpretation to be unreasonable and contrary to the plain meaning of “adjacent” as it would find emission sources to “be adjacent so long as they are functionally related, irrespective of the distance that separates them.”¹⁵¹ Thus, at least in the Sixth Circuit, the EPA’s regional staff will no longer be inquiring about the functional relationship between multiple, far-flung emission sources.

C. Oil and Gas Aggregation after *Summit*

The Sixth Circuit denied the EPA’s motion for rehearing, and the Agency declined to file a petition for a writ of certiorari. Nevertheless, the Agency obstinately adheres to the interrelatedness test. In a December 21, 2012 memorandum, the EPA’s Office of Air Quality Planning and Standards advised regional offices that the *Summit Petroleum* case is binding in the states under the Sixth Circuit’s juris-

147. *Id.* at 742.

148. *Id.*

149. *Id.*

150. *Id.*

151. *Id.* at 744. The Sixth Circuit continued putting the EPA’s interpretation of “adjacent” through the meat grinder for several more pages. However, for the sake of mercy, those reasons will only briefly be described here. First, the court rejected the EPA’s appeal to the longstanding duration of its interdependence test, quipping that “a longstanding error is still an error.” *Id.* It then concluded that the EPA’s interpretation was effectively foreclosed by the 1980 preamble language rejecting the use of an interdependence test. *Id.* at 746–48. This separate consideration of interdependence, alongside the already accepted criterion of proximity, “belies [the EPA’s] current contention that the factors of proximity and functional relatedness are one in the same.” *Id.* at 748. The court continued on to find that the interrelatedness test was inconsistent with the McCarthy memo, which “promotes a neutral and plain meaning application of the” Title V regulations, while failing to mention the interrelatedness test. *See id.* at 749. Lastly, citing an amicus curiae brief by the American Petroleum Institute (“API”), the court found that the EPA’s caution that source determinations should correspond with a “common sense notion of a plant” were “clearly meant to constrain, rather than enlarge” the EPA’s discretion. *Id.* at 750. It also credited API’s explanation of various practical difficulties in applying the interrelatedness test to oil and gas facilities and noted that EPA led itself down the path that, in 1980, it was trying to avoid. *Id.* *Summit*’s source determination took five years, involved at least twenty-five conference calls and the exchange of “a small mountain of paper.” *Id.* at 750–51 (internal quotations omitted). This fine-grained analysis by EPA was expensive, burdensome, and showed exactly why the Agency rejected the interrelatedness test in 1980. *Id.* at 751.

diction (Michigan, Ohio, Tennessee, and Kentucky), but that “EPA does not intend to change its longstanding practice of considering interrelatedness in the EPA permitting actions in other jurisdictions.”¹⁵² The *Summit Petroleum* case was a 2-1 decision, with dissenting Judge Karen Nelson Moore finding that the word “adjacent” is ambiguous, that the EPA is owed deference, and that the majority’s decision “hamstrings” the EPA’s ability to carry out the policy goals of the Clean Air Act.¹⁵³ With the dissent in its pocket and the EPA expressing its commitment to the interrelatedness test in all other jurisdictions, another appeal is probable. This means that a circuit split on the meaning of “adjacent” may be coming soon.

Apart from the federal court system, a state court may have its opportunity to explore the word “adjacent” in one of the most important jurisdictions for shale gas development—Pennsylvania. The Pennsylvania Department of Environmental Protection (“PDEP”) released its final guidance memorandum for performing oil and gas source determinations just two months after the *Summit Petroleum* decision.¹⁵⁴ Originally released as a draft in October 2011,¹⁵⁵ the guidance relied upon dictionary definitions of “contiguous” and “adjacent” to the exclusion of the interrelatedness test.¹⁵⁶ PDEP found that the aggregation of widely dispersed well pads and compressor stations connected by a pipeline “would not comport with the ‘common sense notion of a plant’” and would not be “consistent with the plain meaning of the terms contiguous or adjacent properties.”¹⁵⁷ Rejecting the EPA source determinations as “non-binding” and “merely instructive,” PDEP imposed a “quarter mile rule of thumb . . . properties located a quarter mile or less apart are considered contiguous or adjacent properties . . . [p]roperties located beyond this quarter mile range may only be considered contiguous or adjacent on a case-by-case basis.”¹⁵⁸ PDEP called this a “common sense approach” that complies with the Clean Air Act’s definition of a “source” as a “building,” “structure,” “facility,” or “installation.”¹⁵⁹

Comments from environmental groups pummeled PDEP for relying on the plain meaning of the term “contiguous or adjacent” to exclude the interdependence test.¹⁶⁰ They argued that the quarter mile rule effectively “disallowed aggregation in

152. Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, to Regional Air Division Directors, Regions 1–10 (Dec. 21, 2012), <http://www.epa.gov/nsr/documents/SummitDecision.pdf>, at 1.

153. See generally *Summit Petroleum Corp.*, 690 F.3d at 751–57.

154. PA. DEP’T OF ENVTL. PROT., GUIDANCE FOR PERFORMING SINGLE STATIONARY SOURCE DETERMINATIONS FOR OIL AND GAS INDUSTRIES 1 (Oct. 6, 2012), available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document90745/Final%20Guidance%20for%20Performing%20Single%20Stationary%20Source%20Determinations%20for%20OG%20Industries_Technical%20Guidance10-6-12.pdf.

155. PA. DEP’T OF ENVTL. PROT., GUIDANCE FOR PERFORMING SINGLE STATIONARY SOURCE DETERMINATIONS FOR OIL AND GAS INDUSTRIES 1 (Oct. 12, 2011) available at http://files.dep.state.pa.us/PublicParticipation/Citizens%20Advisory%20Council/CACPortalFiles/Meetings/2011_11/Technical%20Guidance_SingleSource%20Air%20Aggregation_101211.pdf.

156. *Id.* at 5.

157. *Id.* at 3–4.

158. *Id.* at 4.

159. *Id.* at 5.

160. See, e.g., PENNFUTURE, COMMENTS ON GUIDANCE FOR PERFORMING SINGLE STATIONARY SOURCE DETERMINATIONS FOR OIL AND GAS INDUSTRIES (Nov. 21, 2011) [hereinafter PENNFUTURE COMMENTS]; COLUMBIA UNIV SCH. OF LAW, ENVIRONMENTAL LAW CLINIC, COMMENTS ON THE

the context of natural gas operations in Pennsylvania.”¹⁶¹ Among the alleged defects of the draft guidance was its failure to comport with an unspecified dictionary definition of “adjacent,”¹⁶² that it “blatantly ignores the Federal Register definition of a source” by imposing a bright-line rule,¹⁶³ and that it improperly “deemphasizes EPA’s” body of source determinations to which PDEP “must defer” to avoid violating the state’s implementation plan.¹⁶⁴ For this multitude of reasons, each of the environmental groups argued that, if finalized, the PDEP guidance would violate the Clean Air Act for its failure to tow the EPA’s interdependence test line. One group, the Clean Air Council, did not bother to wait for PDEP to finalize the guidance. In February 2012, after PDEP issued the *draft* guidance, the Clean Air Council petitioned the EPA Administrator to find that Pennsylvania was violating its state implementation plan and improperly administering its delegated Title V program, and requesting the EPA Administrator to impose sanctions on Pennsylvania for its failure to adhere to EPA source determinations.¹⁶⁵

For its part, EPA Region III’s comments on the draft were largely identical to those of the environmental groups. It accused PDEP of “attempting to alter the plain meaning of ‘source,’” which is a matter of federal law and would violate Pennsylvania’s implementation plan,¹⁶⁶ and that declining to aggregate oil and gas emission sources spread out over a “large geographic area” . . . would be contrary to federal law.”¹⁶⁷ Although Region III never explicitly called for PDEP to adopt the interrelatedness test, it opined that “by making proximity the only dispositive factor to be considered in determining whether sources are adjacent or contiguous, the interim guidance appears contrary to federal law and the legal and regulatory requirements of the PSD program.”¹⁶⁸

Given the opposition by EPA and environmental groups, it was not surprising that PDEP’s response to comments, issued in October 2012 along with a largely unchanged final version of its guidance document, touted the *Summit Petroleum* decision with some relish. In response to several comments, PDEP noted that the *Summit Petroleum* decision found that viewing adjacency through the lens of “functional relatedness is unreasonable and contrary to the plain meaning of the

“GUIDANCE FOR PERFORMING SINGLE STATIONARY SOURCE DETERMINATIONS FOR OIL AND GAS INDUSTRIES” (Nov. 21, 2011) [hereinafter COLUMBIA COMMENTS] (both on file with author).

161. COLUMBIA COMMENTS, *supra* note 160, at 7.

162. *Id.* at 8.

163. *Id.* at 9.

164. PENNFUTURE COMMENTS, *supra* note 160, at 6.

165. Clean Air Council, Petition to the Administrator to Make a Finding that Pennsylvania is Failing to Implement its State Implementation Plan; To Make a Determination that Pennsylvania is not Adequately Administering and Enforcing its Clean Air Act Title V Permitting Program; and to Apply Sanctions Against Pennsylvania for these Failures (Feb. 16, 2012). The Clean Air Council also based its petition on individual instances where Pennsylvania Department of Environmental Protection did not aggregate wells with compressor stations or other processing plants. *Id.* at 10–13.

166. EPA COMMENTS ON PADEP TECHNICAL GUIDANCE ON AIR AGGREGATION IN OIL AND GAS INDUSTRIES 1 (Nov. 21, 2011).

167. *Id.* at 4.

168. *Id.* at 6.

term.”¹⁶⁹ Despite the Sixth Circuit’s validation, however, EPA’s December 21, 2012 memorandum asserts that it still views the interrelatedness test to be governing law in the Third Circuit.¹⁷⁰ This means that the Clean Air Council’s petition, asserting that PDEP’s rejection of the interrelatedness test violates federal law, could still have appeal to the EPA Administrator. Both the PDEP’s guidance and the *Summit Petroleum* decision will be tested before state courts and administrative boards. Environmental groups are currently challenging PDEP approvals before the Environmental Hearing Board, arguing that gas processing facilities should be aggregated with gas wells.¹⁷¹ To date, no state court or administrative board has required the aggregation of oil and gas emission sources under EPA’s interrelatedness test.

D. Environmental Groups and the Interrelatedness Test

The *Summit Petroleum* decision likely did little to dissuade opponents of oil and gas development from pursuing the interrelatedness test. Environmental groups challenged several decisions not to aggregate oil and gas wells before *Summit Petroleum* and have maintained them after its issuance.¹⁷² These challenges, however, show a key difference between the interrelatedness test as seen by EPA and by some environmental groups. Where EPA will decline to aggregate wells and processing facilities that are arguably interrelated but controlled by different companies, some environmental groups advocate for aggregating them anyway because of their connection via pipeline.

WildEarth Guardians advocated for this approach in its challenge to EPA Region VIII’s renewal of a Title V permit for the BP America Production Company (“BP”) Florida River Compression Facility in Colorado. Before the EPA Environmental Appeals Board (“EAB”), WildEarth Guardians argued that the Florida River station should have been aggregated with BP’s Wolf Point Compression Station and over 1,000 BP-owned or -operated gas wells within 600 square miles of Colorado’s Northern San Juan Basin.¹⁷³ Wolf Point was 4.5 miles away from Florida

169. PDEP, COMMENT AND RESPONSE DOCUMENT CONCERNING THE PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION’S INTERIM FINAL TECHNICAL GUIDANCE ENTITLED GUIDANCE FOR PERFORMING SINGLE STATIONARY SOURCE DETERMINATIONS FOR OIL AND GAS INDUSTRIES 33 (Oct. 6, 2012), available at http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Aggregation_Policy_Comment_and_Response_Document_10-6-2012.pdf.

170. Memorandum from Stephen D. Page, OAQPS, to Regional Air Division Directors (Dec. 21, 2012), available at <http://www.epa.gov/nsr/documents/SummitDecision.pdf>.

171. See Grp. Against Smog and Pollution v. PDEP, No. 2011-065-R, Pa. EHB (Pa. Commw. Ct. filed May 2, 2011); Clean Air Council v. PDEP, No. 2011-072-R, Pa. EHB (Pa. Commw. Ct. filed May 13, 2011); Clean Air Council v. PDEP, No. 2012-141-R, Pa. EHB (Pa. Commw. Ct. filed July 30, 2012); Clean Air Council v. PDEP, No. 2012-1650-R, Pa. EHB (Pa. Commw. Ct. filed Sept. 24, 2012). All case dockets are accessible through the Pennsylvania Environmental Hearing Board’s website: http://ehb.courtapps.com/public/commonsearch_ehb.php.

172. See Grp. Against Smog and Pollution v. PDEP, No. 2011-065-R, Pa. EHB (Pa. Commw. Ct. filed May 2, 2011); Clean Air Council v. PDEP, No. 2011-072-R, Pa. EHB (Pa. Commw. Ct. filed May 13, 2011); Clean Air Council v. PDEP, No. 2012-141-R, Pa. EHB (Pa. Commw. Ct. filed July 30, 2012); Clean Air Council v. PDEP, No. 2012-1650-R, Pa. EHB (Pa. Commw. Ct. filed Sept. 24, 2012). All case dockets are accessible through the Pennsylvania Environmental Hearing Board’s website: http://ehb.courtapps.com/public/commonsearch_ehb.php.

173. Petition for Review, In re: BP Amer. Prod. Co., Appeal No. CAA 10-04, (No. 1) (Env’tl. App. Bd. filed Nov. 18, 2010) [hereinafter Pet. for Rev.] available at

River and the gas wells up to eighteen miles away.¹⁷⁴ The Region found that aggregation was inappropriate due to the presence of thirty-three other companies within the wellfield.¹⁷⁵ Specifically, Florida River, Wolf Point, and BP's wells lacked "exclusive dependency" because BP had operating agreements allowing gas to flow to other companies' gathering lines and compressors.¹⁷⁶ Additionally, BP's compressors could accept gas from other companies' wells.¹⁷⁷ After its review of BP's gathering system, the Region found "dozens of points across the field where BP-gathered gas can be offloaded to other companies' pipelines, compressors, or gas plants *or* where BP may accept gas from non-BP-operated wells and systems."¹⁷⁸ Due to the commingling of gas from different companies and its direction through infrastructure owned and operated by different companies, the Region concluded that Florida River, Wolf River, and the BP wells were not functionally interdependent because, even if one or multiple points shut down, the others could continue operating.¹⁷⁹ Therefore, the Region concluded, the compressors and wells were not "adjacent" because of this operational independence.¹⁸⁰

In its petition for review, WildEarth Guardians opened with the orthodox EPA view of aggregation: "the distance between sources is not necessarily a determinative factor for assessing contiguousness or adjacency, but rather interrelationship. Units that are miles apart commonly fit within the ordinary meaning of 'facility' and 'installation' for aggregation if the sources are integrated and physically connected."¹⁸¹ It parted ways with the agency by assailing the Region for declining to aggregate the compressors and wells based on a belief "that the only time a finding of adjacency would be appropriate from an interrelatedness standpoint is where there exists complete and exclusive interdependence."¹⁸² It asserted that, while pri-

[http://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/35BAC83723EC8E4E852577E000729F84/\\$File/WildEarth%20Guardians...1.pdf](http://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/35BAC83723EC8E4E852577E000729F84/$File/WildEarth%20Guardians...1.pdf); EPA, EPA Region VIII, Response to Comments on the Florida River Compression Facility's March 28, 2008 Draft Title V Permit to Operate at 3, 7, 12 (Oct. 18, 2010) [hereinafter RTC]. All docket material can be accessed at [http://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/ED74782DD76C7C708525786400577848/\\$File/Administrative%20Record%20-%20EPA%20FL%2000036...9.36.pdf](http://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/ED74782DD76C7C708525786400577848/$File/Administrative%20Record%20-%20EPA%20FL%2000036...9.36.pdf).

174. RTC, *supra* note 173, at 7.

175. *Id.* at 7, n. 11. The Region also placed an unusual emphasis on the physical distance between points, detailing that "Wolf Point is physically separate from Florida River . . . and separated by rugged terrain." *Id.* at 7. It also described the BP gas wells as being "spread throughout the entire [600 square mile] basin" and "are not physically contiguous" to the Florida River compression station. *Id.*; *see also id.* at 12 ("[T]he fact that many of BP's [Northern San Juan Basin] wells are located in La Plata County does not mean they are 'adjacent.' La Plata County covers 1,692 square miles, or nearly 1.1 million acres. All BP owned and operated wells that happen to be co-located within such a large area cannot reasonably be said to be 'adjacent' to one another simply because they are located in the same county.").

176. *Id.* at 11.

177. *Id.*

178. *Id.*

179. *Id.* at 13.

180. The EPA Administrator reached a similar conclusion in denying WildEarth Guardians' petition requesting that the Administrator object to a state operating permit issued by the Colorado Department of Public Health and Environment's Air Pollution Control Division for Anadarko Petroleum Corporation's Frederick Compressor Station. Anadarko Petroleum Corporation, Petition Number: VIII-2010-4 (2011), available at http://www.epa.gov/region7/air/title5/petitiondb/petitions/anadarko_response2010.pdf.

181. Pet. for Rev., *supra* note 173, at 22.

182. *Id.* at 25.

or EPA source determinations did not expressly address this point, they implied that emission sources are interdependent whenever they regularly support each other and that temporarily shutting down one source, while the other continues to operate, does not sever their interdependence.¹⁸³ This position can best be summarized as interdependence being a binary concept; two emission sources are either interdependent or they are not. There are no degrees or gradations.¹⁸⁴

Region VIII's brief in response leaned heavily on the deference owed to agency decisions regarding complex technical matters and that its findings of fact and conclusions of law were not clearly erroneous.¹⁸⁵ Briefs by BP and API as an amicus curiae discussed the practical difficulties of implementing WildEarth Guardians' view of the interrelatedness test.¹⁸⁶ To begin, BP's compressors and wells were not, by any normal definition, "contiguous or adjacent" to one another due to the distances involved and the patchwork of intervening ownership rights. As BP noted, the "surface and mineral estates in the Northern San Juan Basin are highly fractured and owned by a mix of entities", including federal, state, tribal, and private parties.¹⁸⁷ This fracturing resulted in "over 60 surface use agreements, pipeline agreements, and rights-of-way just in the area near Florida River."¹⁸⁸ Together, with all of the different oil and gas leases in the area, there is "a maze of boundary lines" near Florida River.¹⁸⁹ This would make administering BP's compressor and well system as a single, unitary source under the Clean Air Act virtually impossible. The location of the well pads was further dictated by surface owner preferences, state spacing orders, the rugged terrain, and proximity to BP's offices and pipelines.¹⁹⁰ This was simply not an example of a company artificially partitioning its operations to escape Title V or PSD permitting requirements.¹⁹¹

The API brief focused on how difficult source determinations for the oil and gas industry become under the interrelatedness test. It explained that well fields, where several different companies commonly do business, involve a complicated

183. *Id.* at 26–28.

184. *Id.* at 29 (stating that "[a]lthough the EPA may argue the nature of interdependency between the Florida River Compression Facility and BP's wells in the vicinity, fundamentally, a relationship of interdependence exists") (emphasis deleted).

185. See generally Response to Petition for Review, *In re* BP Amer. Prod. Co., EAB (Feb. 23, 2011) (No. CAA 10-04, Dkt. No. 9), available at [http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/643E7175F0DE1C888525784100541A4B/\\$File/Region%208%27s%20RESPONSE%20TO%20PETITION%20FOR%20REVIEW...9.pdf](http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/643E7175F0DE1C888525784100541A4B/$File/Region%208%27s%20RESPONSE%20TO%20PETITION%20FOR%20REVIEW...9.pdf).

186. See BP America Production Company's Response to WildEarth Guardians' Petition for Review, *In re* BP Amer. Prod. Co., EAB (Feb. 24, 2011) (No. CAA 10-04, Dkt. No. 10) (EAB) (Feb. 24, 2011) [hereinafter BP Brief] available at [http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/B518FE26EE49F04A8525784200559182/\\$File/BP%27s%20Response%20to%20WildEarth%27s%20Petition%20for%20Review...10.pdf](http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/B518FE26EE49F04A8525784200559182/$File/BP%27s%20Response%20to%20WildEarth%27s%20Petition%20for%20Review...10.pdf); Motion for Leave to File Amicus Curiae Brief in Opposition to the Petition for Review, *In re* BP Amer. Prod. Co., Appeal (No. CAA 10-04, Dkt. No. 11) (EAB) (filed Feb. 24, 2011) [hereinafter API Brief] (amicus brief attached to motion for leave), available at [http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/4E6355C531B2F9EC852578420059F67D/\\$File/Motion%20for%20Leave%20to%20File%20Amicus%20Curiae%20Brief%20-%20Exhibits...11.01.pdf](http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/4E6355C531B2F9EC852578420059F67D/$File/Motion%20for%20Leave%20to%20File%20Amicus%20Curiae%20Brief%20-%20Exhibits...11.01.pdf).

187. BP Brief, *supra* note 186, at 4.

188. *Id.*

189. *Id.*

190. *Id.* at 5–6.

191. See RTC, *supra* note 173, at 11–13 (EPA Region VIII observed that BP had no control over the location of well sites and therefore the policy reasons behind aggregation did not apply).

and enmeshed series of equipment, pipelines, processing facilities, ownership interests, contracts, and cooperative agreements.¹⁹² Practices can include sharing well-head processing equipment and the commingling of different companies' gas in gathering lines.¹⁹³ The gathered gas is frequently diverted to different compressors or processing facilities based on pipeline pressure changes driven by well field activity (e.g., new wells connecting to the system, stimulation of existing wells, maintenance at processing stations, etc.).¹⁹⁴

The cooperation between companies and dynamic gas flow creates two major impediments to WildEarth Guardians' theory of treating all well field emission sources as a single stationary source under the control of a single company. First, no single company would actually have control over the "interrelated" emission sources that it would be obligated to manage under a Title V permit.¹⁹⁵ The permit holder would be required to track the frequent changes to other companies' "interdependent" wells or compressors, be they legal (e.g., changes in ownership or to operating agreements) or physical (a well or compressor going off line) and account for them, lest it risk a Title V permit violation.¹⁹⁶ Second, the complicated gas flow, operating agreements, and frequent turnover of ownership, leasehold, and service contract rights would make defining the gas flow attributable to a single company extremely difficult.¹⁹⁷ As with *Summit Petroleum*, understanding BP's operations in the Northern San Juan Basin involved extensive correspondence, meetings, and submissions between BP and Region VIII.¹⁹⁸ Thus, aggregating oil and gas well emission sources would require exactly the kind of burdensome and subjective analyses that EPA sought to avoid.¹⁹⁹

Unfortunately, the EAB never had an opportunity to issue a decision in the *BP Florida River* appeal. WildEarth Guardians, EPA Region VII, and BP reached a settlement to resolve the appeal.²⁰⁰ Nevertheless environmental groups will continue to press the "interrelatedness" interpretation of aggregation as a way to delay or stop oil and gas development, and EPA regional offices may feel the need to push back against *Summit Petroleum* through more source determinations or an en-

192. API Brief, *supra* note 186, at 18–20.

193. *Id.* at 18–19.

194. *Id.* at 19.

195. *Id.* at 24.

196. For example, Title V permits require monitoring and reporting of emissions monitoring. See WildEarth Guardians' Petition for Review, Exh. 1 at 6–7, *In re BP Am. Prod. Co.*, Appeal No. CAA 10-04, Dkt. No. 1.01 (EAB) (filed Nov. 18, 2010) (copy of BP's Title V permit), available at [http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/35BAC83723EC8E4E852577E000729F84/\\$File/WildEarth%20Guardians...1.pdf](http://yosemite.epa.gov/oa/eab_web_docket.nsf/All%20Content%20-%20Web/35BAC83723EC8E4E852577E000729F84/$File/WildEarth%20Guardians...1.pdf). If all of BP's wells, as well as other companies' wells, were covered under the Title V permit, BP would be compelled to track the gas flow in order to know which wells must be accounted for in measuring their collective emissions. Yet, this gas flow is constantly and unpredictably changing and would require knowledge of its competitors' operations to which BP would not have access.

197. *Id.* at 19–20.

198. *Id.* at 21.

199. *Id.* at 21–23 (citing 45 Fed. Reg. at 52,695 (1980)).

200. Proposed Settlement Agreement, Clean Air Act Citizen Suit, 76 Fed. Reg. 71,027 (proposed Nov. 16, 2011). A copy of the settlement agreement is on file with the author and available upon request.

forcement action. The issue of whether oil and gas emission sources are “contiguous or adjacent” is ripe for a circuit split, and potentially, Supreme Court review.

IV. GREENHOUSE GAS EMISSIONS

The push to develop unconventional gas resources is aided, in part, by its lower carbon dioxide emissions when combusted as compared with coal. Some, however, have questioned whether unconventional gas actually has lower greenhouse gas (“GHG”) lifecycle emissions.²⁰¹ Others want unconventional gas development severely curtailed or prohibited for reasons beyond GHGs²⁰² but may use claims of high lifecycle emissions as a reason to stop hydraulic fracturing. If EPA pursues regulations to directly control methane emissions in the future, they will largely be shaped by the controversy surrounding lifecycle emissions. This section provides an overview regarding the sources and estimated amounts of GHG emissions from unconventional well development as well as EPA’s revised New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants for the oil and natural gas sector.

A. Methane Emissions from Unconventional Wells

Methane is the largest constituent of natural gas.²⁰³ It is a potent greenhouse gas with a global warming potential between twenty-one and twenty-five times that of carbon dioxide.²⁰⁴ As a source of fuel, however, natural gas emits less GHGs than coal.²⁰⁵ This advantage would disappear if natural gas had higher lifecycle GHG emissions than coal. Unconventional gas production involves three stages where methane may be emitted to the atmosphere: completion, liquids unloading, and re-completions.

201. See Robert W. Howarth, et al., *Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations*, 106 CLIMATIC CHANGE LETTERS 507, 679 (June 2011), available at <http://graphics8.nytimes.com/images/blogs/greeninc/Howarth2011.pdf> (last visited Jan. 30, 2013) [hereinafter Howarth Letter]. Life-cycle emissions accounts for all emissions throughout the process of extracting, manufacturing, transporting, or using a product or fuel. *Life-Cycle GHG Accounting Versus GHG Emission Inventories*, available at <http://www.epa.gov/climatechange/waste/downloads/life-cycle-ghg-accounting-versus-ghg-emission-inventories10-28-10.pdf> (last visited Mar. 22, 2013). A lifecycle analysis for unconventional gas would include GHG emissions from the well drilling and completion stages, gathering, processing, transportation by pipeline, and consumption of that gas by the ultimate user. Howarth Letter, *supra* note 201, at 2.

202. See, e.g., *Dirty, Dangerous, and Run Amok*, SIERRA CLUB, <http://content.sierraclub.org/naturalgas/> (last visited Mar. 20, 2013) (stating that “[i]f drillers can’t extract natural gas without destroying landscapes and endangering the health of families, then we should not drill for natural gas”) (internal quotations omitted). *Fracking*, FOOD & WATER WATCH, available at <http://www.foodandwaterwatch.org/water/fracking/> (last visited January 15, 2013) (“Why a Ban? Can’t Better Regulations Make Fracking Safer? No. Fracking is inherently unsafe and we cannot rely on regulation to protect communities’ water, air and public health.”).

203. NSPS TSD, *supra* note 31, at 2-2.

204. IHS Report, *supra* note 32, at 1.

205. See, e.g., Proposed Rule, Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 72 Fed. Reg. 22,392, 22,396 (Apr. 13, 2012) available at <http://regulations.vlex.com/vid/performance-greenhouse-emissions-stationary-364731962> (“Natural gas combustion inherently emits less CO₂ than coal combustion and the technology of choice for generating electricity with natural gas, stationary combined cycle gas turbines, is also more efficient.”).

As explained above, unconventional wells must be “completed” before they can produce natural gas or oil.²⁰⁶ As the flowback shifts from liquids and solids to primarily gas, the methane portion of the flowback is flared, burning the methane off into carbon dioxide.²⁰⁷ Once the flowback turns almost completely to gas, the well is connected to a pipeline and enters its production stage. As gas or oil production declines, the stimulation and completion process may need to be repeated.²⁰⁸ Performing a “recompletion” with hydraulic fracturing fluid involves the same high pressure flowback of liquids and gas with methane flared off.²⁰⁹ Despite these standard industry practices, many seem to believe that flaring is a rarity and that well service companies and their clients prefer to vent methane directly to the atmosphere. As explained below, this causes considerable controversy in estimating greenhouse gas emissions from hydraulically fractured wells.

GHG emissions from natural gas production are included in EPA’s GHG emissions inventory.²¹⁰ EPA estimated that each unconventional well emits 9,175 thousand cubic feet (“Mcf”) of methane per completion.²¹¹ This estimate was assumed to be the same for well recompletions.²¹² After eliminating emissions for wells in states that required flaring, EPA estimated that unconventional gas wells emit approximately 48 billion cubic feet of methane per year.²¹³ According to this estimate, the natural gas industry (emissions from conventional wells, unconventional wells, gas processing, transport, and distribution) was the highest source of methane emissions in 2010.²¹⁴ The results shocked the industry as EPA’s 2010 estimates were more than double its 2006 estimates due to a change in the agency’s estimation methodology.²¹⁵ According to EPA, its prior estimate of 0.02 metric tons of methane per well completion was now increased to a staggering 177 metric tons.²¹⁶

206. Pa. Dep’t of Env’t. Protection, *Act 13 Frequently Asked Questions Act 13*, (last visited Mar. 22, 2013) http://www.portal.state.pa.us/portal/server.pt/community/act_13/20789/act_13_faq/1127392.

207. MARY LASHLEY BARCELLA, SAMANTHA GROSS & SURYA RAJAN, IHS CERA, MISEASURING METHANE: ESTIMATING GREENHOUSE GAS EMISSIONS FROM UPSTREAM NATURAL GAS DEVELOPMENT, 2 (2011) available at http://www.whitehouse.gov/sites/default/files/omb/assets/oir/ra_2060/2060_03282012b-1.pdf.

208. See EPA, LESSONS LEARNED FROM NATURAL GAS STAR PARTNERS: INSTALLING PLUNGER LIFT SYSTEMS IN GAS WELLS 1 (2006), available at http://epa.gov/gasstar/documents/ll_plungerlift.pdf (last visited January 15, 2013).

209. NSPS TSD, *supra* note 31, at 4-3.

210. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010*, EPA 430-R-12-001, 3-46 (Apr. 15, 2012), available at <http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf> [hereinafter GHG Inventory].

211. EPA, GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUS., BACKGROUND TECHNICAL SUPPORT DOCUMENT, 87, available at http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf (last visited Mar. 22, 2013) [hereinafter GHG TSD].

212. *Id.*

213. *Id.* at 88.

214. GHG Inventory, *supra* note 210, at ES-5.

215. IHS Report, *supra* note 32, at 4.

216. *Id.* Overall, the adjustments to how EPA estimated methane emissions for unconventional wells increased its estimates for the natural gas industry as a whole by 204 percent. Am. Petroleum Inst. & Am.’s Natural Gas Alliance, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production, Summary and Analysis of API and ANGA Survey Responses*, 1 (June 1, 2012),

Relying on EPA's estimates, a study from Cornell University calculated that nearly two percent of all natural gas from unconventional wells will be vented to the atmosphere.²¹⁷ Combined with estimated emissions from well maintenance, processing, transport, storage, and distribution, the study concluded that fugitive methane emissions increased to between roughly 3.5 percent and nearly eight percent.²¹⁸ In a total lifecycle comparison to coal-fired electricity generation, the analysis concluded that "the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion."²¹⁹ These findings were quickly incorporated into a study by the Post Carbon Institute, criticizing shale gas,²²⁰ and publicized by the New York Times.²²¹

Given that government statistics and analyses are often presumed to be credible, and the quick utilization of the GHG inventory calculations by the Howarth Letter, the EPA's estimates for unconventional well methane emissions required close scrutiny. At least two analyses of the EPA's assumptions and methodologies have severely criticized its published methane estimates. A joint survey by the American Petroleum Institute ("API") and America's Natural Gas Alliance ("ANGA") of 91,000 wells showed significantly lower methane emissions (637,766 metric tons) than that estimated by the EPA (4.5 million metric tons).²²² According to the API and ANGA survey, this puts the oil and gas industry behind bovine digestion in terms of methane emissions.²²³

The API/ANGA study attributed the significant discrepancy to poor quality data and methodological problems with the EPA's emissions inventory, including a low number of samples (approximately 8,880)²²⁴ and an inconsistent characterization of conventional and unconventional wells,²²⁵ as well as several flawed assumptions about how gas developers actually operate. A report by industry consultant IHS CERA noted that the EPA assumed that, contrary to industry practice, no unconventional well completions flared methane emissions unless required by law. It also criticized EPA for relying on data regarding methane captured from experimental control methods, and rounding emissions upwards to a significant degree

available at <http://www.iogawv.com/resources/Docs/APIANGA%20Study%20on%20Methane%20Emissions.pdf> (last visited Mar. 22, 2013) [hereinafter API/ANGA Survey].

217. Howarth Letter, *supra* note 201, at 3, 5.

218. *Id.* at 5, 7.

219. *Id.* at 9.

220. See J. David Hughes, *Will Natural Gas Fuel America in the 21st Century?* POST CARBON INST., 27 (May 2011) available at <http://www.scribd.com/doc/55274994/PCI-Report-Nat-Gas-Future> (last visited Mar. 22, 2013) (The Howarth et al. analysis and the EPA report indicate that shale gas may have few or none of the GHG-reduction benefits much advertised by natural gas proponents when life-cycle emissions are considered on a twenty-year time frame).

221. Tom Zeller, Jr., *Methane Losses Stir Debate on Natural Gas*, N.Y. TIMES, (Apr. 12, 2011) available at <http://green.blogs.nytimes.com/2011/04/12/fugitive-methane-stirs-debate-on-natural-gas/> (last visited Mar. 22, 2013).

222. API/ANGA Survey, *supra* note 216.

223. *Id.* at 26.

224. *Id.* at 2, 15.

225. *Id.* at 4. Note that the term "unconventional well" generally connotes one that produces oil or gas from shale, tight sand, or coalbed methane formations. See NSPS TSD, *supra* note 31, at 4-9.

(on the order of 1,000 to 100,000 cubic feet).²²⁶ Additionally, the EPA's analysis included two errors that, under its own assumptions, would have driven its calculations of methane emissions even higher. First, it underestimated the number of wells completed in a year.²²⁷ Second, it erroneously claimed that hydraulically fractured wells do not require a periodic maintenance process called "liquids unloading" that removes fluids and debris from the well with some methane emissions involved.²²⁸

Although the API/ANGA survey did not collect data on completion emissions, the IHS Report made three main points undercutting the credibility of the EPA's estimates. First, it noted that, if the EPA's assumptions about the volume of methane venting during well completion were correct, they would create toxic atmospheres around the well sites that would endanger workers.²²⁹ Even if workers would not be routinely asphyxiated under the EPA's assumptions, methane is extremely flammable and, if the EPA was correct, would regularly ignite from nearby diesel engines and other equipment.²³⁰ Second, IHS pointed out that if each newly completed well vented pure methane for an entire ten-day completion, it would still result in a fraction of the EPA's estimates for methane emissions from gas field production.²³¹ Lastly, it pointed out that well developers have every economic incentive to capture gas as quickly as possible after completion rather than let their product disappear into thin air.²³²

Where the EPA's analysis drew the sharpest criticism, however, was in a comparison of its assumptions to API and ANGA's survey responses.

- The EPA assumed that ten percent of unconventional wells require recompletions. Survey data showed that only 1.6 percent required recompletions with hydraulic fracturing.²³³
- The EPA assumed 41.3 percent of conventional wells vented methane to the atmosphere during liquids unloading. Survey data showed that only eleven percent of conventional wells and sixteen percent of unconventional wells did so.²³⁴
- The EPA assumed that, during liquids unloading, methane vented to the atmosphere for an average time of three hours. Survey data showed that venting time for conventional wells was 0.77 hours and, for unconventional wells, 1.48 hours.²³⁵

226. IHS Report, *supra* note 32, at 5–8. The IHS Report and EPA appear to agree that flaring reduces methane emissions by approximately ninety-eight percent. *Id.* at 4.

227. API/ANGA Survey, *supra* note 216, at 5–7.

228. Compare GHG TSD, *supra* note 211, at 90 (calculating emissions from liquids unloading for only conventional wells while stating that "unconventional wells . . . will not require liquid [sic] unloading") with API/ANGA Survey, *supra* note 216, at 12, Table 5 (providing survey responses regarding unconventional wells subject to liquids unloading).

229. IHS Report, *supra* note 32, at 8.

230. *Id.* at 1.

231. *Id.* at 8.

232. *Id.* at 2.

233. API/ANGA Survey, *supra* note 216, at 15.

234. *Id.* at 12.

235. *Id.*

The IHS Report concluded that the Howarth Letter similarly overestimated methane emissions in its GHG lifecycle comparison with coal by relying on largely the same data as the EPA and making several errors in manipulating another data set.²³⁶ It also argued that the Howarth Letter assumed, not only that all flowback methane emissions are directly vented to the atmosphere (as opposed to being captured or flared), but that flowback methane emission rates were actually higher than the wells' production rates.²³⁷ Several other studies have disputed the findings of the Howarth Letter but limited or inconsistent data and methodological variability has made any consensus about the true GHG lifecycle emissions for shale gas elusive.²³⁸ The importance of determining lifecycle GHG emissions from unconventional gas wells, and the related question of whether direct regulation of methane emissions, will likely be blunted by 2015. That is the compliance date for installing green completion equipment under the EPA's revised New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants for oil and gas sources.

B. The Oil and Gas NSPS

As described previously, the EPA's August 2012 revisions to the Oil & Gas NSPS was the first time the agency considered emissions from hydraulic fracturing. With the agency's use of methane as a surrogate for VOCs,²³⁹ and its requirement for green completions, the EPA strongly advertised the co-benefits of indirect methane reductions. Methane controls were not only desired by environmental groups, but the EPA touted green completions as an \$11 million net cost savings to the industry from the recovery of salable gas and natural gas liquids.²⁴⁰ Methane control and recovery made the Oil & Gas NSPS a compromise for the EPA, where it tried to give something to both sides. Environmental groups got indirect methane emission reductions, but the EPA expressly declined to directly regulate methane it-

236. IHS Report, *supra* note 32, at 9.

237. *Id.* at 9–10. The IHS Report also argued that, as with EPA's assumptions, were the Howarth Letter's assumption correct, unconventional well sites would routinely suffer explosions. *Id.*

238. JEFFREY LOGAN ET AL., NATURAL GAS AND THE TRANSFORMATION OF THE U.S. ENERGY SECTOR: ELECTRICITY 3 available at <http://www.nrel.gov/docs/fy13osti/55538.pdf> (last visited Mar. 22, 2013). Other studies disagreeing with the Howarth Letter's conclusions are: Frances O'Sullivan & Sergey Paltsev, *Shale Gas Production: Potential Versus Actual Greenhouse Gas Emissions*, 7 ENVTL. RESEARCH LETTERS 4 (Nov. 26, 2012), available at http://iopscience.iop.org/1748-9326/7/4/044030/pdf/1748-9326_7_4_044030.pdf; Mohan Jiang et al., *Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas*, 6 ENVTL. RESEARCH LETTERS 3, 1 (2011), available at http://iopscience.iop.org/1748-9326/6/3/034014/pdf/1748-9326_6_3_034014.pdf; Andrew Burnham et al., *Life Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal and Petroleum*, 46 ENVTL. SCI. & TECH. 619, 629–27 (2012); Nathan Hultman et al., *The Greenhouse Impact of Unconventional Gas for Electricity Generation*, 6 ENVTL. RESEARCH LETTERS 4, 1 (2010), http://iopscience.iop.org/1748-9326/6/4/044008/pdf/1748-9326_6_4_044008.pdf; Timothy Skone & Robert James, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant*, NAT'L ENERGY TECH. LABORATORY (Sept. 30 2010), available at http://www.netl.doe.gov/energy-analyses/pubs/NGCC_LCA_Report_093010.pdf; Trevor Stephenson et al., *Modeling the Relative GHG Emissions of Conventional and Shale Gas Production*, 45 ENVTL. SCI. & TECH. 10757 (2011) available at <http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3238415/>.

239. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. at 49,513(Aug. 16, 2012) (to be codified at 40 C.F.R. pts. 60 and 63).

240. *Id.* at 49,534.

self,²⁴¹ which is what environmental groups really wanted.²⁴² Instead, the EPA pleaded that it needed more time “to evaluate the appropriateness of regulating methane.”²⁴³ And while the green completion and flaring requirements were not terribly expensive or burdensome for industry (which was often implementing these controls already), the EPA applied these controls to recompleted wells as “modified” sources²⁴⁴ and wells with very low VOCs in the flowback.²⁴⁵ The trade-off was that industry received its requested compliance date extension for green completions until January 1, 2015.²⁴⁶

Methane control, albeit indirectly, will now be a requirement at all hydraulically fractured gas wells. The Clean Air Act, however, requires the EPA to review, and possibly revise, the Oil & Gas NSPS within eight years.²⁴⁷ Whether future revised standards will require further control of methane will largely depend on the resolution of the EPA’s emission estimate controversy, described above, and demands that the EPA directly regulate methane emissions from the oil and gas industry, described below.

C. Litigation to Require Further Methane Regulation

For the EPA, an agency feeling tensions between an Administration touting the economic and environmental benefits of the hydraulic fracturing-induced energy bonanza and environmental groups demanding stringent GHG controls on shale gas production, the Oil & Gas NSPS probably felt like a solid political compromise. For a group of state attorneys general, however, the new regulations were not enough. On December 11, 2012, seven state attorneys general sent the EPA a notice of their intent to sue the agency under the Clean Air Act to force a determina-

241. *Id.*

242. CRAIG H. SEGALL & SIERRA CLUB ET AL., OIL AND NATURAL GAS SECTOR: NEW SOURCE PERFORMANCE STANDARDS AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS REVIEWS; PROPOSED RULE FOR SUBPART OOOO, DOC. ID. EPA-HQ-OAR-2010-0505-4240 AT 72–80 (Nov. 30, 2011), *available at* <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4240> (click “View Attachment” in “Comments” under “Attachment” section).

243. 77 Fed. Reg. at 49,513.

244. *Id.* at 49,512–13.

245. *Id.* at 49,515–16.

246. *Id.* at 49,517–19. Note that the issues described above are just the controversies involving the green completion and flaring standards that affect hydraulically fractured wells. Both industry and environmental groups had several other bones of contention with the remainder of the NSPS and NESHAP that apply to downstream sources. The views of industry and environmental groups are generally described in the following comments: SEGALL, *supra* note 242; DEVORAH ANCEL & SIERRA CLUB, ET AL., NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: OIL AND NATURAL GAS SECTOR; REVIEW AND PROPOSED RULE FOR 40 C.F.R. PART 63, Doc. ID EPA-HQ-OAR-2010-0505-4457 (Nov. 30, 2011); *available at* <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4457> (click “View Attachment” in “Comments” under “Attachment” section); Letter from Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute to Assistant Administrator Regina McCarthy, U.S. Env’tl. Prot. Agency (Nov. 30, 2011) *in* COMMENT ON OIL AND NATURAL GAS SECTOR: NEW SOURCE PERFORMANCE STANDARDS AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS REVIEWS; PROPOSED RULE, Doc. ID. EPA-HQ-OAR-2010-0505-4266, *available at* <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4266>, (click “View Attachment” in “Comments” under “Attachment” section).

247. 42 U.S.C. § 7411(b)(1)(B) (2012).

tion that methane emissions must be directly regulated.²⁴⁸ Relying on the very data criticized by other studies, and apparently failing to consider the future methane reductions from the Oil & Gas NSPS, the attorneys general concluded that more regulations are necessary to control the “vast quantities of methane” emitted by the oil and gas sector.²⁴⁹

In their notice letter, the attorneys general assert that the EPA failed to satisfy a mandatory duty to directly regulate methane.²⁵⁰ Essentially, the notice letter argues that the EPA was required to either directly regulate methane or affirmatively decline to do so within the New Source Performance Standard’s eight-year review period²⁵¹ instead of stating that it needed more time to evaluate the decision.²⁵² The notice letter hangs much of its force on claims that the oil and gas sector is the second largest source of U.S. greenhouse gas emissions, behind only electric utilities.²⁵³ This means that any real evaluation of whether the EPA must directly regulate methane from unconventional gas wells will be significantly influenced by its emission estimates. As discussed above, industry groups deeply criticized the EPA’s GHG inventory data and methodology for unconventional well emissions.²⁵⁴ A rulemaking process to directly regulate methane would open up that data and methodology to public notice and comment for the first time. Once the EPA irons out how to estimate methane emissions from unconventional wells, it would then have to account for the reductions required by the Oil & Gas NSPS. Given these variables, the EPA stood on firm ground when it deferred methane regulation under the Oil & Gas NSPS until it could further evaluate the question as the current GHG inventory estimates for the sector are now virtually worthless. Due to the substantial impact the attorneys general’s suit would have on the oil and gas sector, the industry would likely attempt to intervene to make these arguments as well as others.²⁵⁵

V. CONCLUSION

Hydraulically fractured unconventional wells will likely be a large part of the United States’ energy policy for a long time. And while the industry may be locked in battles about potential groundwater contamination at the moment, the various requirements of the Clean Air Act will occupy its time over the long term. Long after the EPA and states conclude their various ground water studies, regulators and industry will be coping with revisions to various ambient air quality standards, in-

248. Letter from Eric T. Schneiderman et al., to Lisa P. Jackson, EPA (Dec. 11, 2012), available at http://www.ag.ny.gov/pdfs/ltr_NSPS_Methane_Notice.pdf (last visited January 30, 2013). The notice is on behalf of the attorneys general of New York, Connecticut, Delaware, Maryland, Massachusetts, Rhode Island, and Vermont. *Id.*

249. *Id.* at 1 (citing to the EPA’s “compelling data” from the Natural Gas Star Program that was criticized in the IHS Report).

250. *Id.* at 2.

251. See 42 U.S.C. § 7411(b)(1)(B) (2012).

252. Schneiderman et al., *supra* note 248 at 3 (citing 77 Fed. Reg. at 49,513).

253. *Id.* at 4.

254. See Schneiderman et al., *supra* note 248; see also SEGALL, *supra* note 242.

255. For example, there may be an argument that the attorneys general suit is time-barred. EPA’s decision to defer regulating methane was made in the Oil & Gas NSPS final rule. The suit could be viewed as an attempt to collaterally challenge that decision outside of the sixty-day window that a party may petition for review of a final agency action under 42 U.S.C. § 7607(b)(1) (2012).

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BE ABOUT AIR, NOT WATER

dustry-wide performance standards, and Clean Air Act permitting issues, not to mention a series of Clean Air Act lawsuits by hydraulic fracturing opponents. If an oil and gas company's focus is not already on air issues, they will be soon.