Flowback: Federal Regulation of Wastewater from Hydraulic Fracturing

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INTRODUCTION

A variety of production techniques, including hydraulic fracturing ("fracking"), have opened new reserves of natural gas from unconventional sources in the United States.[1] The resulting

1. *See infra* notes 14–27 and accompanying text. *See also* U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-12-874, UNCONVENTIONAL OIL AND GAS DEVELOPMENT: KEY ENVIRONMENTAL AND PUBLIC HEALTH REQUIREMENTS 1 (2012) [hereinafter GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT], *available at* http://www.gao.gov/assets/650/647782.pdf ("[A]dvances in horizontal drilling techniques combined with hydraulic fracturing have recently increased domestic production of oil and natural gas from such onshore unconventional formations."); GROUND WATER PROT. COUNCIL, MODERN SHALE GAS DEVELOPMENT IN THE

growth of natural gas production in the last decade has dramatically altered the U.S. energy picture.[2] Increasing supplies of natural gas have lessened reliance on coal for electricity generation, and the United States may be poised to be an exporter of natural gas.[3]

The expansion of natural gas production through fracking has, however, generated significant controversy. Although much of the controversy has focused on the environmental impact of the fracking process itself,[4] the enormous quantities of contaminated wastewater produced by fracking also raise environmental concerns.[5] Wastewater generated from oil and gas production, generally known as "produced water," typically contains toxic constituents including metals, naturally occurring radioactive

UNITED STATES: A PRIMER 8 (2009) [hereinafter MODERN SHALE GAS DEVELOPMENT], *available at* http://www.gwpc.org/sites/default/files/Shale%20Gas%20Primer%202009.pdf.

2. Shale gas produced by hydraulic fracturing is expected to account for almost half of domestic production in the next twenty-five years. *See infra* notes 28–393 and accompanying text.

3. As of August 2011, three permits were pending before the Department of Energy requesting authorization to export liquefied natural gas. *See* OFFICE OF ENERGY ANALYSIS, EFFECT OF INCREASED NATURAL GAS ON DOMESTIC ENERGY MARKETS 20 (2012), *available at* http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf*; U.S. Opportunity to Export: Sabine Pass Liquefaction Project*, CHENIERE ENERGY, www.cheniere.com/lng_industry/sabine_pass_liquefaction.shtml (last visited Apr. 15, 2014).

4. One of the most controversial aspects of fracking is its potential to contaminate drinking water supplies. The Academy Award nominated movie *Gasland*, with its image of flaming tap water, created widespread public concern. *See, e.g.*, Bryan Walsh, *A Documentary on Natural Gas Drilling Ignites an Oscar Controversy*, TIME (Feb. 26, 2011), http://science.time.com/2011/02/26/a-documentary-on-natural-gas-drilling-ignites-an-oscar-controversy/. The Environmental Protection Agency ("EPA"), for some time, has been engaged in a long-term study of the potential impact of fracking on drinking water supplies. *See* ENVTL. PROT. AGENCY, OFFICE OF RESEARCH AND DEV., PLAN TO STUDY THE POTENTIAL IMPACTS OF HYDRAULIC FRACTURING ON DRINKING WATER RESOURCES 11 (2011) [hereinafter EPA HF STUDY PLAN], *available at* http://water.epa.gov/type/groundwater/uic/class2/hydraulic fracturing/upload/hf_study_plan_110211_final_508.pdf; *see also* ENVTL. PROT. AGENCY, OFFICE OF RESEARCH AND DEV., STUDY OF THE POTENTIAL EFFECTS OF HYDRAULIC FRACTURING ON DRINKING WATER SUPPLIES: PROGRESS REPORT 17 (2012) [hereinafter 2012 HF STUDY PROGRESS REPORT], *available at* http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/hf_study_plan_110211_final_508.pdf. Other environmental concerns associated with fracking, include air pollution, oil spills, and diversion of vast quantities of clean water. *See* Thomas W. Merrill & David M. Schizer, *The Shale Oil and Gas Revolution, Hydraulic Fracturing, and Water Contamination: A Regulatory Strategy,* 98 MINN. L. REV. 145, 170–197 (2013). The most fundamental impact of fracking, however, may be that expanded production of relatively low-cost natural gas will delay the transition to non-carbon based renewable energy. *See, e.g.*, Thomas W. Merrill, *Four Questions about Fracking*, 63 CASE W. RES. L. REV. 971, 992 (2013).

5. Estimates of the amounts generated are in the billions of gallons per year. *See infra* notes 70–74 and accompanying text.

materials, and high concentrations of salts and total dissolved solids. The portion of produced water generated during the early period of operation of a fracked well, known as "flowback," may also have constituents derived from chemicals used in the fracking process itself.[6] Proper management and disposal of this wastewater is one of the major challenges for environmentally sustainable fracking.[7]

Congress has largely excluded the fracking process itself from federal regulation,[8] and most regulation of fracking has been at the state and local levels.[9] The U.S. Environmental Protection Agency ("EPA"), however, has substantial authority to regulate the management and disposal of wastewater generated by fracking. Hazardous wastes are subject to regulation under the Resource Conservation and Recovery Act ("RCRA"), and classification of fracking wastewaters as a RCRA hazardous waste would have significant implications for their management. Since 1988, however, EPA has excluded most oil and gas wastes, including fracking wastewater, from regulation as a hazardous waste under RCRA.[10]

EPA also has authority under the Clean Water Act ("CWA") to regulate the discharge of fracking wastewater to surface water.[11] EPA has promulgated national "technology-based" effluent

6. *See infra* notes 75–82 and accompanying text for a discussion of the constituents of produced water and flowback.

7. *See infra* notes 83–101 and accompanying text for a discussion of current management techniques. The Obama Administration has stated "[i]n order to take full advantage of this important domestic energy resource, we must proactively address concerns that have been raised regarding potential negative impacts associated with hydraulic fracturing ('fracking') practices." THE WHITE HOUSE, BLUEPRINT FOR A SECURE ENERGY FUTURE 13 (2011), *available at* http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf.

8. *See infra* notes 53–662 and accompanying text.

9. *See, e.g.*, Christopher S. Kulander, *Shale Oil and Gas State Regulatory Issues and Trends*, 63 CASE W. RES. L. REV. 1101, 1103 (2013); *see also* NATHAN RICHARDSON ET AL., THE STATE OF STATE SHALE GAS REGULATION 5 (2013), *available at* http://www.rff.org/rff/documents/RFF-Rpt-StateofStateRegs_Report.pdf.

10. A petition requesting removal of this exclusion filed by the Natural Resources Defense Council is pending before EPA. Letter from Amy Mall, Senior Policy Analyst, Natural Res. Def. Council, to Lisa Jackson, Adm'r., U.S. Envtl. Prot. Agency, Re: Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy (Sept. 8, 2010) [hereinafter NRDC Petition], *available at* http://docs.nrdc.org/energy/files/ene_10091301a.pdf.

11. Congress has limited regulation of stormwater runoff from oil and gas sites under the Clean Water Act. *See* Clean Water Act, 33 U.S.C. § 1342(l)(2) (2012). This article does not address the issues associated with stormwater runoff from fracking facilities.

limitations that prohibit the direct discharge of most wastewater generated from onshore oil and gas activities, including wastewater generated by fracking in shale formations.[12] EPA's existing regulations do not, however, prohibit the discharge of all fracking wastewater. Discharge from off-site private and public treatment systems is authorized. Also, EPA claims that the national prohibition on the direct discharge of wastewater does not apply to wastewater generated from fracking to produce coal bed methane ("CBM"). EPA has considered, but recently proposed to abandon, development of national regulations for the discharge of wastewater from CBM activities.

This Article addresses issues associated with federal regulation of fracking wastewater under RCRA and the CWA.[13] Part I discusses the fracking process and current federal regulation of the fracking process itself under the Safe Drinking Water Act. Part II addresses the potential adverse environmental impacts of fracking wastewater, as well as the management and disposal options currently employed within the industry.

Part III discusses issues associated with EPA's exclusion of this wastewater from classification as a hazardous waste under RCRA. The Article suggests that the focus on the existing exclusion is something of a red herring since it appears that little, if any, fracking wastewater would be classified as a hazardous waste in the absence of this exclusion. The significant issue for regulation of fracking wastewater under RCRA is not whether wastewater should be exempt from hazardous waste classification but whether EPA could, or should, specifically list fracking wastewater as a hazardous waste. This step would open up a variety of regulatory options through EPA's use of the technique of "conditional exclusion."

Part IV addresses regulation of the direct discharge of fracking wastewater to surface water under the Clean Water Act. First, the

12. *See infra* notes 152–164 and accompanying text.

13. Under the Safe Drinking Water Act, EPA also regulates the disposal of fracking wastewater by injection into disposal wells. *See infra* notes 53–62 and accompanying text. The focus of this article, however, is on the regulatory issues relating to the regulation of fracking wastewater as a hazardous waste and the surface discharge of fracking wastewater. This Article also does not address separate issues associated with fracking on federal and Indian lands. The Bureau of Land Management has proposed regulations directly addressing management of fracking activities on federal and Indian lands. *See* Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, 77 Fed. Reg. 27,691 (proposed May 11, 2012) (to be codified at 43 C.F.R. pt. 3160). The BLM regulation that currently addresses regulation of fracking, 43 C.F.R. pt. 3162.3–2, has not been revised since 1988. *See id.* at 27,693.

Article discusses the legal basis for EPA's national prohibition on the direct discharge of wastewater from all fracking activities other than production of CBM. The Article next argues that EPA's original exclusion of CBM wastewater from this prohibition was not factually justified nor implemented through appropriate administrative procedures. Absent EPA's exclusion, the direct discharge of CBM wastewaters is currently prohibited. Second, the Article addresses issues associated with EPA's national regulation of wastewater discharged by privately owned Centralized Waste Treatment facilities ("CWTs"). Third, the Article discusses an alternate basis for regulating the discharge of fracking wastewater to surface waters from CBM facilities and CWTs. The Clean Water Act confers substantial authority to impose restrictions on the discharge of fracking wastewater through case-by-case technology-based limits according to the permit writer's "best professional judgment" ("BPJ").

Finally, Part V discusses issues associated with the regulation of fracking wastewater sent to Publicly Owned Treatment Works ("POTWs"). EPA currently has no categorical pretreatment standards that limit the introduction of fracking wastewaters to POTWs. This Article argues that the Clean Water Act and EPA's existing policies require EPA to develop such pretreatment standards for fracking wastewater.

I. HYDRAULIC FRACTURING

A. The Fracking Process

Extraction of natural gas has traditionally involved collection of oil and gas rising through a vertically drilled well. Typically, natural pressure forces oil and natural gas to rise up the borehole for collection at the surface.[14] Supplies of natural gas from conventional sources are limited by the ability to drill into gas-containing formations and by the ability of gas to flow to the borehole.

In the last forty years, changes in the extraction process have allowed access to previously unavailable supplies of natural gas

14. Extraction of oil and gas can include "enhanced" recovery techniques that increase the amount of product recovered from conventional sources. These enhanced techniques for recovery of conventional oil are generally considered to be distinct from the newer process of horizontal drilling and hydraulic fracturing. *See* Legal Envtl. Assistance Found., Inc. v. EPA, 276 F.3d 1253, 1261 n.6 (11th Cir. 2001).

from unconventional sources, including shale, tight sandstone, and coal bed formations.[15] Development of horizontal drilling techniques, for example, has allowed multiple wells drilled from a single site to reach gas formations located in areas thousands of feet away.[16] It is now common for two to eight wells to be drilled from a single drill pad.[17]

The most significant and controversial change that has allowed extraction from unconventional sources has been the development of hydraulic fracturing or "fracking." Fracking, undertaken after completion of the production well, involves injecting large volumes of water into natural gas formations to fracture the subsurface structures and provide pathways for the gas to migrate to the wells.[18] Wells generally undergo multiple fracturing stages and millions of gallons of water may be injected during the completion process.[19]

Fluids injected to facilitate fracking contain a variety of substances including "propping" agents that hold fractured pathways open, friction reducers, acids, biocides and a variety of other chemical additives that may include guar gel, nitrogen or carbon dioxide gases, gelled oil, diesel oil, sodium hydroxide,

15. The Government Accountability Office has noted "[t]here is no clear and consistently agreed upon distinction between conventional and unconventional oil and gas, but unconventional sources generally require more complex and expensive technologies for production, such as the combination of horizontal drilling and multiple hydraulic fractures." GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 5. *See infra* notes 28–52 and accompanying text for a discussion of unconventional sources of natural gas.

16. *See* GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 10. Horizontal wells are typically used in shale and tight sandstone formations, whereas vertical wells have typically been used for extraction of coal bed methane. *See* 2012 HF STUDY PROGRESS REPORT, *supra* note 4, at 17. Advances in horizontal drilling techniques have increased the economic attractiveness of horizontal drilling in coal bed formations. *See* Greg Meszaros et al., *New Tools Enable CBM Horizontal Drilling*, E&P (July 31, 2007), http://www.epmag.com/archives/features/536.htm.

17. *See* MARY TIEMANN & ADAM VANN, CONG. RESEARCH SERV., HYDRAULIC FRACTURING AND SAFE DRINKING WATER ACT REGULATORY ISSUES 2 (2012), *available at* http://www.fas.org/sgp/crs/misc/R41760.pdf. Materials prepared for the Department of Energy state "[s]ix to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells." MODERN SHALE GAS DEVELOPMENT, *supra* note 1, at ES-3.

18. MODERN SHALE GAS DEVELOPMENT, *supra* note 1 at ES-4.

19. *See id.* (noting that typical shale gas drilling and fracking processes can use from 2 to 4 million gallons of water). Fracking to produce shale gas can, however, require up to 13 million gallons of water. *See* 2012 HF STUDY PROGRESS REPORT, *supra* note 4, at 14. Less water is required to produce coal bed methane. *Id.* (reporting that up to 65,000 gallons of water may be used in fracking to produce CBM).

hydrochloric acid, sulfuric acid, and fumeric acid.[20] Chemicals added to facilitate fracking may constitute one percent of water-based fracking fluids.[21] One of the many controversies over fracking involves the limitations on public disclosure of the constituents of proprietary fracking formulations.[22]

Although hydraulic fracturing has been used since the 1940s to facilitate extraction of natural gas from conventional sources,[23] federally supported research in the 1970's aided the development of fracking to extract natural gas from unconventional sources.[24]

20. *See Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, ENVTL. PROT. AGENCY (March 6, 2012), http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_coalbedmethanestudy.cfm. [hereinafter 2004 EPA HF Impacts Study]; *see also* Leaf Envtl. Assistance Found. v. EPA, 118 F.3d 1467, 1471 (11th Cir. 1997).

21. 2012 HF STUDY PROGRESS REPORT, *supra* note 4, at 28.

22. A number of states have passed requirements for disclosure of the constituents of fracking fluid, but concerns over trade secrecy have led to states to adopt disclosure laws of varying stringency. *See generally* Keith B. Hall, *Hydraulic Fracturing: Trade Secrets and the Mandatory Disclosure of Fracturing Water Composition,* 49 Idaho L. Rev. 399. (2013); MATTHEW MCFEELY, NATURAL RES. DEF. COUNCIL, STATE HYDROFRACTURING DISCLOSURE LAWS AND ENFORCEMENT: A COMPARISON, *available at* http://www.nrdc.org/energy/files/Fracking-Disclosure-IB.pdf (2012). In addition, the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission have established a national hydraulic fracturing chemical registry. *See* FRAC FOCUS: CHEMICAL DISCLOSURE REGISTRY, http://fracfocus.org/ (last visited June 3, 2014). EPA is considering action under the Toxic Substances Control Act to require companies to provide information about fracking fluids. Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, 78 Fed. Reg. 41,768 (2013).

23. *See* Daniel R. Cahoy, Joel Gehman, & Zhen Lei, *Fracking Patents: The Emergence of Patents as Information-Containment Tools in Shale Drilling,* 19 MICH. TELECOMM. & TECH. L. REV. 279, 283–86 (2013). The first experimental fracking operation was performed in 1947 in what appears to have been a "conventional" limestone formation. *See* 2004 EPA HF Impacts Study, *supra* note 20, at A-1, app. A, Dept. of Energy Hydraulic Fracturing Whitepaper. One report states that fracking treatments "reached more than 3,000 wells a month for stretches during the mid-1950s." *See* CARL T. MONTGOMERY & MICHAEL B. SMITH, SOC'Y OF PETROLEUM ENG'RS, HYDRAULIC FRACTURING: HISTORY OF AN ENDURING TECHNOLOGY 27 (2010), *available at* http://www.ourenergypolicy.org/wp-content/uploads/2013/07/Hydraulic.pdf. Actually, fracking has been traced to the 1860's when nitroglycerin "torpedoes" were inserted into wells to fracture subsurface formations. *See Shooters – A "Fracking" History,* AM. OIL & GAS HISTORICAL SOC'Y, http://aoghs.org/technology/shooters-well-fracking-history/ (last visited Aug. 7, 2014).

24. *See* MICHAEL SHELLENBERGER ET. AL., THE BREAKTHROUGH INST., WHERE THE SHALE GAS REVOLUTION CAME FROM: GOVERNMENT'S ROLE IN THE DEVELOPMENT OF HYDRAULIC FRACTURING IN SHALE (2012), *available at* http://thebreakthrough.org/images/main_image/Where_the_Shale_Gas_Revolution_Came_From2.pdf; Ted Nordhaus and Michael Shellenberger, *Lessons from the Shale Revolution,* THE AMERICAN (Feb. 22, 2013), *available at* http://www.american.com/archive/2012/february/lessons-from-the-shale-revolution ("[V]irtually all subsequent commercial fracturing technologies have been built upon the basic understanding of hydraulic fracturing first demonstrated by the Department of Energy in the 1970s."); Kevin Begos, *Fracking Developed with Decades of Government Investment,*

An alternative energy tax credit adopted in 1980 also encouraged the commercial production of gas from unconventional sources.[25] As of 2005, natural gas from unconventional sources had increased to forty-six percent of the nation's production.[26] Unconventional sources of natural gas now account for sixty percent of estimated recoverable onshore natural gas reserves.[27]

B. Unconventional Sources of Natural Gas Through Fracking

Fracking has allowed access to natural gas from three underground formations that previously could not yield commercial quantities of natural gas.

1. Shale

"Shale gas" results from extraction of natural gas from subsurface shale formations.[28] Shale is generally located thousands of feet below ground in low-permeability or "tight" formations from which gas cannot be profitably extracted without fracking.[29] Shale formations are located in various areas across the continent, including the Marcellus Shale in Pennsylvania and West Virginia, the Barnett Shale in Texas, the Bakken Shale in North Dakota and Montana, the Haynesville and Fayetteville Shale formations in Louisiana and Arkansas, and the Mancos Shale in Wyoming and Colorado.[30]

Fracking has dramatically expanded production of shale gas.[31] Although shale gas constituted only 2% of domestic production of natural gas in 2001, in 2011 shale gas accounted for nearly 30% of total domestic natural gas production.[32] The Energy Information

HUFFINGTON POST (Sept. 23, 2012), http://www.huffingtonpost.com/2012/09/23/fracking-developed-government_n_1907178.html.

25. *See* SHELLENBERGER ET AL., *supra* note 24, at 7 (describing the effect of the Section 29 production tax credit for nonconventional gas contained in the 1980 Crude Oil Windfall Profit Tax Act, P.L. 96-223).

26. MODERN SHALE GAS DEVELOPMENT, *supra* note 1.

27. *Id.* at 3.

28. *Id.* at 1.

29. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 5.

30. MODERN SHALE GAS DEVELOPMENT, *supra* note 1, at 16–24.

31. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 1–2.

32. SEC. OF ENERGY ADVISORY BD., SHALE GAS PRODUCTION SUBCOMMITTEE 90-DAY REPORT 6 (2011), *available at* http://energy.gov/sites/prod/files/Final_90_day_Report.pdf.

Administration projects that shale gas will constitute almost half of U.S. production in the next twenty-five years.[33]

2. Tight Sandstone

Natural gas can also be extracted from tight sandstone.[34] Tight sandstone consists of formations with unconnected "pores" with low permeability.[35] Tight sandstone basins are located in a number of states including Texas, Louisiana, Pennsylvania, New York, Colorado, Wyoming and Montana.[36] Fracking techniques in tight sandstone formations are similar to those used in shale formations.[37] Gas produced from tight sandstone is a significant and growing source of domestically produced natural gas.[38] In 2009, natural gas from tight sandstone formations accounted for 28% of domestic production.[39]

3. Coal Bed Methane

"Coal bed methane" is natural gas extracted from coal beds. The majority of CBM has come from coal formations in the West, including the Powder River, Raton, Greater Green River, San Juan and Uinta basins; the Gulf Coast, including the Black Warrior and

33. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 2; *Producing Natural Gas from Shale*, U.S. DEP'T OF ENERGY (Jan. 26, 2012), http://energy.gov/articles/producing-natural-gas-shale.

34. *See* GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 12. As with shale gas, the development of fracking techniques before 1980 spurred the development of extraction of gas from tight sandstone. *See* SHELLENBERGER ET. AL., *supra* note 22.

35. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 1. A report from the Congressional Research Service states:

> The crucial geologic difference between tight sand gas formations and shale gas formations is that shale gas formations are both the source rock and the reservoir rock. The natural gas is formed within the shale layers, but because shale is virtually impermeable to flow, the gas remains trapped and bound to the matrix of organic matter in the shale. Shale gas formations are also deemed unconventional gas deposits.

PETER FOLGER, MARY TIEMANN, & DAVID BEARDEN, CONG. RESEARCH SERV., THE EPA DRAFT REPORT OF GROUNDWATER CONTAMINATION NEAR PAVILLION, WYOMING: MAIN FINDINGS AND STAKEHOLDER RESPONSES, CONGRESSIONAL RESEARCH SERVICE 16 (2012).

36. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1 at 7.

37. *See National Oil and Gas Assessment 2013 Assessment Update*, U.S. GEOLOGICAL SURVEY, http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment/AssessmentUpdates.aspx (last updated May 15, 2013).

38. *See* U.S. ENERGY INFO. ADMIN., NATURAL GAS PRICES: STATE PORTFOLIO STANDARDS INCREASE RENEWABLE GENERATING CAPACITY (2010), *available at* http://www.eia.doe.gov/oiaf/aeo/pdf/trend_4.pdf.

39. *See* EPA HF STUDY PLAN, *supra* note 4, at 11.

Cahaba basins; and from formations in the Gulf Coast and Appalachian regions of the country, including portions of Virginia, West Virginia, Ohio and Pennsylvania.[40]

Unlike shale gas, CBM tends to be extracted from shallower formations and the coal beds themselves are "looser" and more likely to allow subsurface migration of gas and fracking fluids.[41] CBM is produced, in part, through dewatering of the coal bed formation to generate pressures that allow the gas to be recovered,[42] but most production of CBM also involves fracking.[43] Volumes of wastewater decline over the life span, typically five to fifteen years, of gas production.[44] As discussed below, the earliest regulatory issues involving fracking arose in the context of fracking activities to generate CBM.[45]

Significant efforts to produce CBM began in the 1970's,[46] and CBM has been produced in commercial quantities since 1981.[47]

40. See ENVTL. PROT. AGENCY, COALBED METHANE EXTRACTION: DETAILED STUDY REPORT 1-1 (2010) [hereinafter CBM DETAILED STUDY REPORT], *available at* http://water.epa.gov/scitech/wastetech/guide/304m/upload/cbm_report_2011.pdf; ALL CONSULTING & MONTANA BOARD OF OIL & GAS CONSERVATION, COAL BED METHANE PRIMER: NEW SOURCES OF NATURAL GAS-ENVIRONMENTAL IMPLICATIONS 18–24 (2004) [hereinafter DOE CBM PRIMER], *available at* http://www.oilandgasbmps.org/docs/GEN03-CBMPRIMER FINAL.pdf.

41. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 5. EPA has stated that coal bed methane reservoirs "are typically closer to the surface and in greater proximity to USDWs [underground sources of drinking water] compared to conventional gas reservoirs." *Hydraulic Fracturing Background Information*, ENVTL. PROT. AGENCY, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydrowhat.cfm (last updated May 9, 2012). CBM formations range in depth from 450 feet to more than 10,000 feet. *See* EPA HF STUDY PLAN, *supra* note 4, at 11.

42. *See* ENVTL. PROT. AGENCY, TECHNICAL SUPPORT DOCUMENT FOR THE 2010 EFFLUENT GUIDELINES PROGRAM PLAN 17-1 (2011) [hereinafter TSD 2010 EG PROGRAM PLAN], *available at* http://water.epa.gov/scitech/wastetech/guide/304m/upload/tsd_effluent_program_10_2011.pdf.

43. *See* EPA HF STUDY PLAN, *supra* note 4, at 11; 2004 EPA HF IMPACTS STUDY, *supra* note 20, app. A-1–A-3; AM. PETROLEUM INST., WATER MANAGEMENT ASSOCIATED WITH HYDRAULIC FRACTURING 5 (2010), *available at* http://www.shalegas.energy.gov/resources/HF2_e1.pdf; *see also* Legal Envtl. Assistance Found. v. E.P.A., 118 F.3d 1467, 1470 (11th Cir. 1997).

44. *See* ENVTL. PROT. AGENCY, OFFICE OF WATER, TECHNICAL DEVELOPMENT DOCUMENT FOR THE COALBED METHANE (CBM) EXTRACTION INDUSTRY 3-1–3-2 (2013) [hereinafter EPA TECHNICAL DEVELOPMENT DOCUMENT FOR CBM], *available at* http://water.epa.gov/scitech/wastetech/guide/oilandgas/upload/cbmttd2013.pdf.

45. *See infra* notes 48–49 and accompanying text.

46. U.S. Steel and the Bureau of Mines undertook test projects for production of CBM in the 1970's. *See* Elizabeth A. McClanahan, *Coalbed Methane: Myths, Facts and Legends of Its History and the Legislative and Regulatory Climate into the 21st Century*, 48 OKLA. L. REV. 471, 473 (1995).

Alabama issued what may have been the first permit for a CBM well in May 1980,[48] and, as early as 1982, EPA was addressing Clean Water Act permitting issues arising from commercial production of CBM.[49] CBM now constitutes a significant source of domestic gas, but its production is tied to the overall price of natural gas.[50] In a 2011 report, EPA stated:

> In 2009, natural gas production from coalbed methane reservoirs made up 8 percent of the total US natural gas production; this percentage is expected to remain relatively constant over the next 20 years if current trends and policies persist."[51]

Trends apparently did not continue, and only two years later EPA stated that the falling price of shale gas has substantially limited the economic viability of CBM production.[52]

C. Federal Regulation of the Fracking Process

The Underground Injection Control ("UIC") provisions of the federal Safe Drinking Water Act ("SDWA") provide the basic authority for federal regulation of the injection of materials into wells.[53] Under UIC programs, the "underground injection" of materials into "underground sources of drinking waters" ("USDW") requires a permit that includes restrictions on construction and operation of the well.[54] States may be delegated "primary" regulatory authority to implement these UIC requirements, and EPA approves this delegation of authority based on its

47. Gary C. Bryner, *Coalbed Methane Development: The Costs and Benefits of an Emerging Energy Resource*, 43 NAT. RESOURCES J. 519, 523 (2003).

48. *See Coalbed Methane Resources of Alabama*, GEOLOGICAL SURVEY OF ALA. STATE OIL AND GAS BD, http://www.gsa.state.al.us/documents/oginfo/cbm.pdf (last visited Aug. 7, 2014). CBM wells may have been extracted in Alabama during the 1970's in order to degasify coal wells. *See Coalbed Methane and Fracking,* BLACK WATER RIVERKEEPER, http://blackwarriorriver.org/coalbed-methane.html (last visited Aug. 7, 2014).

49. *See infra* notes 177–80 and accompanying text. *See infra* notes 152–64 and accompanying text for a discussion of Clean Water Act permit requirements.

50. *See* ENVTL. PROT. AGENCY, 820-R-13-006, ECONOMIC ANALYSIS FOR EXISTING AND NEW PROJECTS IN THE COALBED METHANE INDUSTRY 1 (2013) [hereinafter EPA ECONOMIC ANALYSIS OF CBM INDUSTRY], *available at* http://water.epa.gov/scitech/wastetech/guide/oilandgas/upload/cbmea2013.pdf.

51. EPA HF STUDY PLAN, *supra* note 4, at 11.

52. *See infra* notes 228–235 and accompanying text.

53. Safe Drinking Water Act §§ 1421–29, 42 U.S.C. §§ 300h–h-8 (2012).

54. 40 C.F.R. § 145.11(a)(5).

determination that the state UIC program meets minimum federal regulatory requirements.[55]

EPA has established six classes of wells that undertake "underground injection,"[56] and different regulatory requirements apply to the different classes of wells.[57] Wells receiving materials both for purposes of oil and gas production and waste disposal are classified as Class II wells under the UIC program.[58]

Federal regulation of the fracking process under the SDWA has a checkered history. Prior to 1997, EPA took the position that the injection of fracking fluids was not regulated under the SDWA. In EPA's view, injection for purposes of fracking was not "underground injection" since the "principal function" of fracking was not the underground emplacement of fluids but the extraction of natural gas.[59] In *Legal Environmental Assistance Foundation v. EPA, (LEAF I)*, the Eleventh Circuit rejected this position and held that fracking in coal bed formations was "underground injection" that must be regulated under the UIC program.[60] The case, which involved a challenge to the Alabama UIC program, had limited national effect,[61] and EPA stated that it would study the impact of

55. 42 U.S.C. § 300h-1; 40 C.F.R. § 145.1.

56. 40 C.F.R. § 144.6. Class I wells are wells used to dispose of hazardous, industrial, or municipal wastes beneath underground sources of drinking water. *Id.* §144.6(a). Class II wells are wells that receive fluids "(1) [w]hich are brought to the surface in connection with . . . conventional oil or natural gas production . . . and (2) [f]or enhanced recovery of oil or natural gas; and (3) [f]or storage of hydrocarbons." *Id.* § 144.6(b). Class III wells are wells that inject for the purpose of extraction of minerals. *Id.* § 144.6(c). Class IV wells are wells used to dispose of hazardous or radioactive wastes into or above underground sources of drinking water. *Id.* § 144.6(d). Class V wells are injection wells not included in Classes I, II, III, or IV. *Id.* §144.6(e). Class VI wells are wells used for sequestration of carbon dioxide. *Id.* § 144.6(f).

57. *See* 40 C.F.R. §§ 146.1–.95 (2014).

58. *See Class II Wells—Oil and Gass Related Injections Wells*, ENVTL. PROT. AGENCY, http://water.epa.gov/type/groundwater/uic/class2/index.cfm (last updated May 9, 2012). *See also* GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 18.

59. *See* Legal Envtl. Assistance Found. v. EPA, 118 F.3d 1467, 1471 (11th Cir. 1997) [hereinafter *LEAF I*].

60. It characterized EPA's argument that a CBM well is not regulated under the UIC because it is used primarily for gas extraction as "spurious." *Id.* at 1475.

61. *LEAF I* involved a challenge to Alabama's UIC program based on its failure to address fracking in coal bed formations. EPA's response was to approve a revised Alabama UIC program that included regulation of fracking as "Class II-like injection activities." 65 Fed. Reg. 2889 (2000). In a subsequent case challenging this approval, the court upheld EPA's approach to approval of the Alabama program (*LEAF II*) but concluded that fracking wells constituted Class II wells under EPA's regulatory provisions. Legal Envtl. Assistance Found. v. EPA, 276 F.3d 1253 (11th Cir. 2001) [hereinafter *LEAF II*]. The actual results of the *LEAF* litigation were (1) a holding by one circuit that hydraulic fracturing into coal bed formations

fracking in coal bed formations before it took additional regulatory action.[62]

Two events followed soon after the *LEAF* decisions that dramatically affected the application of the SDWA to fracking nationwide. In 2003, the largest producers of fracking fluids, Halliburton, B.J. Services, and Schlumberger, entered into a voluntary "Memorandum of Agreement" ("MOA") with EPA in which they agreed not to include diesel fuel in fracking fluids used to produce CBM.[63] The voluntary MOA did not contain any agreement about the applicability of the SDWA to the fracking process nor did it limit, even on a voluntary basis, the use of diesel fuel as a fracking additive in shale gas formations.

In 2005, however, Congress largely exempted the fracking process from regulation under the SDWA. In the Energy Policy Act of 2005, Congress amended the definition of "underground injection" in the SDWA expressly to exclude the injection of fluids and propping agents, other than "diesel fuel," undertaken pursuant to hydraulic fracturing.[64] The effect of the amendment has been to ensure that, unless diesel oil is included in the fracking fluid, the fracking process itself is excluded from regulation under

was subject to Class II requirements of the UIC and (2) EPA's approval of the revision of a single state UIC program.

62. EPA stated:

> In the wake of the Eleventh Circuit's decision, EPA decided to assess the potential for hydraulic fracturing of CBM wells to contaminate USDWs. EPA's decision to conduct this study was also based on concerns voiced by individuals who may be affected by CBM development, Congressional interest, and the need for additional information before EPA could make any further regulatory or policy decisions regarding hydraulic fracturing.

2004 EPA HF IMPACTS STUDY, *supra* note 20, at ES-7.

63. Memorandum of Agreement between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corp. (Dec. 12, 2003), *available at* http://www.epa.gov/safewater/uic/pdfs/moa_uic_hyd-fract.pdf.

64. Energy Policy Act of 2005, Pub. Law 109-58, 42 U.S.C. § 1421(d)(1)(B) (2012). Section 322 of the Act defines "underground injection" as follows:

> The term "underground injection"—(A) means the subsurface emplacement of fluids by well injection; and (B) excludes—(i) the underground injection of natural gas for purposes of storage; and (ii) the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.

the SDWA.[65] In 2012, EPA published "guidance" on the issuance of UIC permits where diesel fuel is included in the fracking fluid.[66] This guidance defines the limited circumstances in which the fracking process itself is subject to UIC permit requirements.

II. FRACKING WASTEWATER

Among the major environmental challenges associated with fracking is the proper management and disposal of the vast amounts of contaminated wastewater generated by the process. Although most wastewater from fracking to extract shale gas is injected into disposal wells,[67] a significant portion of fracking wastewater is discharged to surface water. Discharges of fracking wastewater can result in significant adverse environmental impacts. As EPA has noted with respect to CBM discharges:

> Coalbed methane-produced water discharges can impact receiving surface waters and soils. Saline discharges from coalbed methane

65. Although prior to *LEAF I* EPA had claimed that fracking was not subject to the SDWA, EPA posted a statement on its website in 2010 stating that fracking involving diesel fuel requires a permit under the SDWA. Industry groups challenged the legality of EPA's assertion of permitting authority without going through the notice and comment process. *See* Opening Brief of Appellants, Indep. Petroleum Ass'n of Am. v. EPA, No. 10-1233 (D.C. Cir. Mar. 31, 2011). The case was settled with an agreement that EPA would revise language on the web page to, among other things, include a reference to EPA permitting guidance. Settlement Agreement at 2–3, Indep. Petroleum Ass'n of Am. v. EPA, No. 10-1233 (D.C. Cir. Feb. 23, 2012), *available at* http://www.eenews.net/assets/2012/02/24/document_gw_01.pdf.

66. ENVTL. PROT. AGENCY, EPA 816-R-12-004, PERMITTING GUIDANCE FOR OIL AND GAS HYDRAULIC FRACTURING ACTIVITIES USING DIESEL FUELS – DRAFT: UNDERGROUND INJECTION CONTROL PROGRAM GUIDANCE #84 (2012), *available at* http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/hfdieselfuelsguidance.pdf. The guidance also addresses the definition of "diesel fuel." *Id.* at 6–9.

67. EPA has a rather benign view of the disposal of fracking wastewater in UIC wells. In a study of CBM disposal options, EPA stated:

> By injecting produced water with high salt content or other contaminants deep underground, Class II wells prevent surface contamination of soil and water. CBM produced water typically has lower TDS concentrations than the water in the injection zone. If the well is properly designed, maintained, and operated, there is little risk of groundwater contamination from produced water.

CBM DETAILED STUDY REPORT, *supra* note 40, at 3–16. The trick, of course, is assuring that Class II wells are "properly designed, maintained, and operated." There is also increasing concern that disposal of wastewater in Class II wells is associated with increased earthquake activity. *See* Bryan Walsh, *Deep Disposal Wells from Oil and Gas Drilling Linked to Earthquakes,* TIME (July 12, 2013), http://science.time.com/2013/07/12/deep-disposal-wells-from-oil-and-gas-drilling-linked-to-earthquakes/.

> operations can adversely affect aquatic life. The large volume of water discharged can also cause stream bank erosion and salt deposition, creating hardpan soil. Long-term impacts include sodium buildup, reduction of plant diversity, mobilization of salts and other elements, and alteration of surface and subsurface hydrology.[68]

EPA is evaluating the environmental consequences of surface disposal of fracking wastewater as part of its long-term study of the impact of fracking on drinking water resources.[69] This part describes the common contaminants associated with fracking wastewater, as well as options for management and disposal of such wastewater.

A. Wastewater Generated During the Fracking Process

The primary wastewater generated by oil and gas production consists of groundwater remaining after the separation of oil and natural gas. This wastewater is generally described as "produced water,"[70] and all oil and gas operations generate it in significant quantities.[71] The quantities of wastewater generated during natural gas extraction vary widely depending both on the formation from which the gas is extracted, the form of fracking, and the geographic location of the well.[72] A single hydraulic fracture can generate 10,000 to 60,000 barrels of flowback, and a single well may undergo fracking over a dozen times during its life.[73] EPA estimated that over 47 billion gallons of produced waters were generated in the production of CBM in 2008.[74]

68. Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. 66,293 (Oct. 26, 2011).

69. *See* EPA HF STUDY PLAN, *supra* note 4.

70. Produced water, because of its typically high salt content, is also known as brine or saltwater waste. ARGONNE NAT'L LAB., ENVTL. SCI. DIV., PRODUCED WATER VOLUMES AND MANAGEMENT PRACTICES IN THE UNITED STATES 13 (2009), *available at* http://www.ipd.anl.gov/anlpubs/2009/07/64622.pdf.

71. One estimate of the average "water to gas ratio" for onshore natural gas production in 2007 was 260 bbl/Mmcf. *Id.* at 8.

72. *See* U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-12-156, ENERGY-WATER NEXUS: INFORMATION ON THE QUANTITY, QUALITY, AND MANAGEMENT OF WATER PRODUCED DURING OIL AND GAS DEVELOPMENT 10–11 (2012) [hereinafter GAO ENERGY-WATER NEXUS], *available at* http://www.gao.gov/assets/590/587522.pdf.

73. *Id.* at 12.

74. CBM DETAILED STUDY REPORT, *supra* note 40, at 3–8. Data from 1997 suggests that all onshore oil and gas activities in the United State daily generate 57 million gallons of wastewater. *See* Argonne Nat'l Lab., *supra* note 70, at 47. This may underestimate the actual quantities of produced water. GAO ENERGY-WATER NEXUS, *supra* note 72, at 9.

Produced waters contain a variety of contaminants not uniquely associated with the fracking process. Wastewaters typically are highly saline with a high "sodium absorption ratio" (SAR).[75] They may also contain total dissolved solids ("TDS"), metals and "naturally occurring radioactive material" ("NORM").[76] The particular constituents and their concentration can vary depending on the formation from which the gas is extracted.[77]

Produced waters are generated throughout the life of a well,[78] but only a portion of produced water generated during the early stage of gas production is thought to contain significant quantities of constituents introduced during the fracking process. This portion of produced water is known as "flowback." The amount of produced water containing flowback varies by well and declines with the age of the well, but EPA has stated that between 10% and 70% of injected fracking fluids return to the surface.[79] A

75. One court described the measurement of sodium and salinity content of CBM wastewater:

> SAR adversely affects the physical properties of soil, resulting in deterioration of the soil's hydraulic characteristics such as permeability. SAR is an expression of the concentration of sodium relative to the concentrations of calcium and magnesium in water. Salinity is indicated by electrical conductivity (EC). It means the ability of water to conduct an electrical current. The EC of water represents the amount of total dissolved solids in the water and is expressed as microSiemens per centimeter (<<mu>>S/cm), micromhos per centimeter (<<mu>>mhos/cm), or as total dissolved solids, TDS, in units of mg/I. Id. EC directly affects a plant's ability to uptake water, while SAR affects the soils in which the plants grow.

Pennaco Energy Co. v. EPA, 692 F. Supp. 2d 1297, 1303–04 (D. Wyo. 2009) (citations omitted).

76. Referring generally to produced waters generated in the oil and gas industry, EPA has stated that produced waters contain "High concentrations of chloride, sodium, magnesium, potassium; Organic compounds such as benzene, naphthalene, toluene, phenanthrene, and oxygen-demanding compounds; Inorganics such as lead, arsenic, barium, antimony, sulfur and zinc; and Radionuclides including uranium, radon, and radium." *See* U.S. ENVTL. PROT. AGENCY, TECHNICAL SUPPORT DOCUMENT FOR THE 2004 EFFLUENT GUIDELINES PROGRAM PLAN 5–218 (2004) [hereinafter TSD 2004 EG PROGRAM PLAN], *available at* http://water.epa.gov/scitech/wastetech/guide/304m/upload/2008_08_19_guide_304m_2004_tsd.pdf. *See also* OFFICE OF SOLID WASTE AND EMERGENCY RESPONSE, U.S. ENVTL. PROT. AGENCY REPORT TO CONGRESS: MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY III-33 (1987), *available at* http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/sierra_ex12_97/Ex._66_-_EPA_Report_to_Congress_-_part_1.pdf.

77. *See* ARGONNE NAT'L LAB., *supra* note 70, at 14.

78. *SEE* EPA TECHNICAL DEVELOPMENT DOCUMENT FOR CBM, *supra* note 44 at 3-1–3-2.

79. *See* Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. 66,286–295 (Oct. 26, 2011); 2012 HF STUDY PROGRESS REPORT, *supra* note 4, at 19 ("For a hydraulic

substantial portion of flowback occurs in the first thirty days of gas production.[80]

Flowback contains not only the constituents typically found in produced water, but also chemicals from the fracking fluid itself.[81] Thus, flowback generally contains not only metals, TDS, salts and NORM, but also hazardous constituents contained in the fracking fluid. EPA has identified large numbers of chemical constituents in the produced water and flowback that comprise fracking wastewater.[82]

B. Disposal Options for Fracking Wastewater

Wastewater from fracking is generally disposed of or managed in one of a number of ways. The management technique employed is affected by the quantities of wastewater generated, the location of the well-site, the composition of the wastewater and state regulatory requirements.[83] As the Government Accountability Office notes, the "primary driver" for decisions about management of wastewater from oil and gas activities is "ultimately, cost."[84]

fracturing job that uses 5 million gallons of hydraulic fracturing fluid, this means that between 500,000 and 3.5 million gallons of fluid will be returned to the surface.").

80. *Id* at 84; JAMES SILVA, RPSEA FINAL REPORT 08122-36, PRODUCED WATER PRETREATMENT FOR WATER RECOVERY AND SALT PRODUCTION 1 (2012), *available at* http://www.rpsea.org/media/files/project/18621900/08122-36-FR-Pretreatment_Water_Mgt_Frac_Water_Reuse_Salt-01-26-12.pdf. The flowback period—the time during which substantial amounts of fracking materials return to the surface—varies, but is typically described as occurring during the first days to weeks. *See* EPA HF STUDY PLAN, *supra* note 4, at 43; Lara O. Haluszczak, Arthur W. Rose, Lee R. Kump, *Geochemical Evaluation of Flowback Brine from Marcellus Gas Wells in Pennsylvania, USA*, 28 APPLIED GEOCHEMISTRY 55 (Jan. 2013), *available at* http://catskillcitizens.org/learnmore/Fracking-Flowback-Brine.pdf. In its study of the impact of hydraulic fracturing on drinking water resources, EPA considers "flowback" to include wastewaters generated after fracking but before the well is placed into production. HF STUDY PLAN, *supra* note 4, at 15.

81. *See* Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. at 66,295.

82. *See* 2012 HF STUDY PROGRESS REPORT, supra note 4, at app. A, Table A-3, A-4. FracFocus, a website operated by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission, manages an online registry of constituents used in fracking fluids. *See FracFocus: Chemical Disclosure Registry*, www.fracfocus.org (last visited Aug. 7, 2014).

83. *See generally* AM. PETROLEUM INST., *supra* note 43, at 20–23); ARGONNE NAT'L LAB., *supra* note 66. EPA's 2010 CBM Report states "[t]he produced water management methods used in a particular basin depend on a variety of factors such as water quantity, water quality, availability of receiving waters, availability of formations for injection, landowner interests, and state regulations." CBM DETAILED STUDY REPORT, *supra* note 40, at 3–12.

84. GAO Energy-Water Nexus, *supra* note 72, at 14.

1. Disposal in Injection Wells

A substantial portion of fracking wastewater is currently disposed of by injection into Class II disposal wells regulated under the SDWA.[85] There are approximately 30,000 active Class II disposal wells operating in the United States,[86] with most of these wells located in Texas, California, Wyoming, Kansas, New Mexico and Louisiana.[87] Most of the wastewater generated from fracking in shale formations is injected into disposal wells.[88] A portion of the produced water generated during production of CBM is also disposed of by injection into disposal wells.[89]

2. Treatment and Surface Discharge

In some cases, fracking wastewaters are treated and discharged to surface waters. Under EPA's current policies, CBM facilities may directly discharge their fracking wastewaters,[90] and EPA has estimated that 45% of produced waters from CBM are directly discharged into navigable waters.[91] EPA has further stated that over 70% of fracking wastewater generated from the Powder River Basin in Colorado and Montana is directly discharged.[92]

Fracking wastewater is also sent to off-site privately owned Centralized Waste Treatment ("CWT") facilities for treatment.[93] Some CWTs directly discharge treated fracking wastes to surface water;[94] others send the treated waste for disposal by publicly owned treatment works.[95]

85. *Id.* at 15. *See* Modern Shale Gas Development, *supra* note 1, at 68 ("Underground injection has traditionally been the primary disposal option for oil and gas produced water. In most settings, this may be the best option for shale gas produced water.").

86. The GAO reports that approximately 20% of the 151,000 active SDWA Class II wells are used for disposal of oil and gas wastewater. GAO UNCONVENTIONAL OIL AND GAS DEVELOPMENT, *supra* note 1, at 90.

87. GAO ENERGY-WATER NEXUS, *supra* note 67, at 17.

88. *See* MODERN SHALE GAS DEVELOPMENT, *supra* note 1, at 69.

89. *See* CBM DETAILED STUDY REPORT, *supra* note 40, at 3–14.

90. *See infra* Part IV for a discussion of CWA regulation of the discharge of fracking wastewater.

91. Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. 66,293 (Oct. 26, 2011).

92. *Id.*

93. Attachment to Memorandum from James A. Hanlon, Dir., Office of Wastewater Mgmt., to Water Div. Dirs., Regions 1–10, Regulating Natural Gas Drilling in the Marcellus Shale under the NPDES Program 11 (Mar. 17, 2011 [hereinafter Hanlon Memo], *available at* http://www.epa.gov/npdes/pubs/hydrofracturing_faq_memo.pdf.

94. Although the direct discharge of shale gas wastewater from the well site is prohibited, this same wastewater sent to a CWT for treatment may be discharged to surface waters. *See*

Fracking wastewater is also sent to municipal sewage treatment plants, known as a "Publicly Owned Treatment Works." The discharge from the POTW itself is subject to regulation under the permit requirements of the Clean Water Act; wastes sent to a POTW are regulated under the "pretreatment" program of the Clean Water Act.[96] However, there are currently no national categorical "pretreatment" regulations applicable to wastewater generated from onshore fracking. [97]

3. Reuse, Recycling, and Evaporation

Fracking wastewater can be reused by reinjection into the fracking well, not for disposal, but for additional fracking.[98] Reuse of wastewater for fracking is complicated by the fact that fracking waters must meet certain levels of quality that wastewater generally does not meet. Therefore, reuse and recycling may require extensive treatment of the wastewater prior to reinjection.[99] In some cases, wastewater is also "recycled" by use in agriculture or livestock watering.[100] Depending on climate and location, some wastewaters are managed by use of on-site evaporation ponds that eliminate the need for disposal of produced water.[101]

III. REGULATION OF FRACKING WASTEWATER AS A HAZARDOUS WASTE

Fracking wastewaters contain a variety of hazardous constituents,[102] and one significant issue associated with management of fracking wastewaters is whether they should be

infra notes 236–48 and accompanying text for a discussion of EPA requirements for the discharge of fracking wastewater from a CWT.

95. EPA has stated that 90% of CWTs receiving shale gas wastewater discharge to POTWs. *See* Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. at 66,296.

96. *See infra* Part V for a discussion of CWA requirements applicable to POTWs and facilities that send wastes to POTWs.

97. *See infra* Part IV.D.2 and accompanying text.

98. *See* MODERN SHALE GAS DEVELOPMENT, *supra* note 1, at 67.

99. *Id.*

100. CBM DETAILED STUDY REPORT, *supra* note 40, at 3-17–3-18; DOE CBM PRIMER, *supra* note 40, at 18. EPA regulations authorize the use of fracking wastewaters for agricultural and livestock watering in certain cases. *See* 40 C.F.R. §§ 435.50–52 (2014) (Oil and Gas Point Source Category, Agricultural and Wildlife Water Use Subcategory).

101. *See* MODERN SHALE GAS DEVELOPMENT, *supra* note 1, at 66–70; CBM DETAILED STUDY REPORT, *supra* note 40, at 3-15.

102. *See* 2012 HF STUDY PROGRESS REPORT, supra note 4, at 5; NRDC Petition, *supra* note 10, at 8–10.

subject to regulation as a "hazardous waste" under the Resource Conservation and Recovery Act. EPA currently excludes fracking wastewater from classification as a hazardous waste, but the impact of this exclusion may be limited. It appears that most fracking wastewaters would not be classified as a hazardous waste even absent the exclusion.

As discussed below, to be subject to regulation under RCRA, fracking wastewaters must be designated as a "listed" hazardous waste. However, listing fracking wastewaters as a hazardous waste would trigger what EPA has considered to be costly and unnecessary requirements. This section identifies and describes those requirements and suggests a method by which EPA could adopt RCRA requirements tailored to address specific environmental concerns arising from management of fracking wastewaters.

A. The RCRA Oil and Gas Exploration and Production Exclusion

1. The Scope of the Exclusion

Since its first RCRA regulations promulgated in 1980, EPA has excluded certain oil and gas wastes, including produced water, from regulation as a hazardous waste.[103] Even before these regulations took effect, however, Congress amended RCRA to suspend regulation of most oil and gas and mining wastes pending EPA's study and determination whether regulation of the wastes under RCRA was "unwarranted."[104] In 1988, EPA issued a

103. *See* 45 Fed. Reg. 33,177 (1980) (codified at 40 C.F.R. §261.4(b)(5)). For a discussion of the oil and gas exclusion, see JEFFREY M. GABA & DONALD STEVER, LAW OF SOLID WASTE, POLLUTION PREVENTION AND RECYCLING §§ 6:20–6:22 (2013). Although frequently described as an "exemption," this Oil and Gas E&P provision is included among provisions characterized as "exclusions" from classification as a hazardous waste. *See* 40 C.F.R. 261.4(b) (2014).

104. Section 3001(b)(2)(A) provides:

> Notwithstanding the provisions of paragraph (1) of this subsection, drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy shall be subject only to existing State or Federal regulatory programs in lieu of this subchapter [Subtitle C] until at least 24 months after October 21, 1980, and after promulgation of the regulations in accordance with subparagraphs (B) and (C) of the paragraph.

Solid Waste Act, Pub. L. 96-482, 94 Stat. 2334 (1980).
Section 3001(b)(2)(B) provides:

"Regulatory Determination" that concluded that oil and gas exploration and production wastes did not warrant regulation under RCRA.[105] This conclusion was not based on its determinations that the wastes did not contain hazardous constituents.[106] Rather, EPA's conclusion was based, in part, on its

> Not later than six months after completion and submission of the study required by section 6982 (m) of this title, the Administrator shall, after public hearings and opportunity for comment, determine either to promulgate regulations under this subchapter for drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy or that such regulations are unwarranted.

Id.

Section 8002(m) required EPA to study and report to Congress on the "adverse effects" associated with oil and gas wastes. *Id.* The results of the section 8002(m) study were published in December 1987, in a Report to Congress entitled "Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy." *See* 53 Fed. Reg. 81-01 (1988).

105. Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25,446, 25,456 (July 6, 1988). EPA gave six reasons for its decision not to regulate oil and gas wastes under Subtitle C:

> (1) Subtitle C contains an unusually large number of highly detailed statutory requirements which are both extremely costly and unnecessary for the safe management of oil and gas wastes. Subtitle C does not allow for the consideration of costs and EPA would be unable to craft a regulatory program to reduce or eliminate serious economic impacts of regulation under Subtitle C.
> (2) Congress had indicated that Subtitle C regulations were unwarranted when existing programs can be implemented to protect human health and the environment, and EPA concluded that existing state and federal programs, including those under the Clean Water Act, the Safe Drinking Water Act, and Subtitle D of RCRA are adequate.
> (3) Due to the amount of time it takes to process Subtitle C permits a delay could result which would be disruptive to oil and gas exploration and development.
> (4) Subtitle C regulation would subject oil and gas wastes to land disposal restriction requirements, thus potentially straining Subtitle C facility capacity.
> (5) Application of Subtitle C requirements would duplicate and disrupt existing state authorities that administer programs tailored to the oil and gas industry.
> (6) It would be "impractical and inefficient" to implement Subtitle C for oil and gas wastes because of the permitting burden on regulatory agencies.

See GABA & STEVER, *supra* note 103, § 6:22 n.2.

106. In its published 1988 Regulatory Determination, EPA stated:

> Analysis of field data collected by EPA and presented in the January 1987 technical report shows that a portion of oil and gas wastes contain constituents of concern above EPA health- or environmental-based standards. For example, wastes at 7 percent of the sites generating drilling fluids and 23 percent of the statistically weighted sample sites generating produced water contain one or more of the toxic constituents of concern at levels greater than 100 times the health-based standards. The constituents typically exceeding the standards in drilling fluids are fluoride, lead, cadmium, and chromium. The constituents exceeding the standards in produced water are benzene, arsenic,

determination that existing state and federal programs adequately addressed management of these wastes and that classifying oil and gas wastes as hazardous would result in increased administrative burdens.[107] Perhaps the primary reason given by EPA, however, was that stringent regulation under Subtitle C would be both "extremely costly "and "unnecessary for the safe management of oil and gas wastes."[108]

EPA's Oil and Gas Exploration and Production ("E&P") Waste Exclusion now excludes "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" from classification as a "hazardous waste."[109] In its 1988 Regulatory Determination, EPA defined the class of "associated" wastes to include drilling muds, drilling cuttings, and "well completion, treatment and stimulation fluids."[110] EPA determined that other wastes, not "uniquely" associated with oil and gas activities, were not covered by the exclusion.[111] These "non-excluded wastes" include, among others, "unused fracturing fluids or acids," that may be generated at an oil and gas site.[112] This exclusion does not generally affect the management and injection of the fracking fluids themselves; the original fluids when used in the extraction process would not be classified as a "waste." EPA also stated that produced water injected

> barium, and boron. In addition, wastes at 78 percent of the sample sites generating drilling fluids, and 75 percent of the sample sites generating produced water, contain chlorides at levels greater than 1,000 times the EPA secondary maximum contaminant level for chloride.

Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 24,554–55.

107. *Id.* at 25,456.

108. *Id.* As discussed below, EPA concluded that it had no alternative to imposing costly and unnecessary Subtitle C requirements if oil and gas wastes were classified as hazardous wastes. This conclusion is incorrect. *See infra* notes 140–44 and accompanying text.

109. 40 C.F.R. § 261.4(b)(5).(2014).

110. Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,453–54.

111. *Id.* at 25,443. In 1993, EPA issued a "Clarification" of its regulatory determination that addressed the status of certain wastes associated with oil and gas exploration and production that, among other things stated that: (1) the exemption from hazardous waste status only applied to wastes that are "uniquely" associated with oil and gas exploration and production; and (2) wastes generated from the further treatment of exempt materials were also exempt. Clarification of the Regulatory Determination for Wastes From the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy, 58 Fed. Reg. 15,284-01, 15,285 (Mar. 3, 1993) (to be codified at 40 C.F.R. pt. 261).

112. Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,454.

for enhanced recovery is not a "waste" and therefore not subject to regulation under RCRA.[113]

2. The Effect of the Exclusion

Although much of the controversy over the role of RCRA in regulating fracking wastes has focused on EPA's Oil and Gas E&P Waste Exclusion, it is important to understand that the exclusion operates *only* as an exclusion from classification as a hazardous waste. In other words, if the E&P waste would not be classified as a Subtitle C hazardous waste in the absence of the exclusion, the exclusion is in fact irrelevant.

Would fracking wastewater be regulated as a hazardous waste "but for" the exclusion?[114] One thing is clear. Mere recitation of the hazardous or toxic constituents of fracking fluids and fracking wastewater says nothing about whether the material would be regulated as a Subtitle C hazardous waste. This issue requires an assessment of EPA's regulatory definition of hazardous waste.[115]

Since a hazardous waste is a subset of the broader class of solid wastes, a Subtitle C hazardous waste must first fall within EPA's infamous regulatory definition of "solid waste."[116] RCRA defines solid waste to include liquids, and there is no doubt that wastewater can be a RCRA solid waste if discarded.[117] Although several issues complicate the classification of fracking wastewater that is recycled, wastewater that is disposed of through injection into a disposal well or managed prior to discharge to surface waters would in most cases be RCRA "solid wastes."[118]

113. *Id.* *See supra* note 14 and accompanying text for a discussion of enhanced recovery.

114. The effect of the Oil and Gas E&P Exclusion on other fracking wastes, including drilling muds and cuttings, raises factual and legal issues not addressed in this article. As noted, EPA does not consider "unused fracturing fluids or acids" that may be generated at an oil and gas site to be covered by the exclusion. *See infra* note 112.

115. *See* 40 C.F.R. § 261.3 (2014). EPA's regulatory definition of "solid waste" and "hazardous wastes" apply for purposes of determining whether a material is regulated under Subtitle C of RCRA. *Id.* § 261.1(a).

116. 40 C.F.R. § 261.2 (2014). The regulation mirrors the statutory definition of "solid waste" by defining solid wastes to include "discarded materials." RCRA § 1003(27), 42 U.S.C. § 6903(27) (2012)

117. *Id.*

118. One of the complications, discussed below, arises from the fact that RCRA excludes from classification as a "solid waste" materials that are discharged to surface water in compliance with an NPDES permit or wastes that are placed in a sewage system connected to a Publicly Owned Treatment Works. RCRA § 1003(27), 42 U.S.C. 9603(27) (2012); 40 C.F.R. § 261.4(a)(1)-(2) (2014). *See* GABA & STEVER, *supra* note 103, §§ 2:18–2:19.

Subtitle C, however, only regulates "hazardous" solid wastes, and a solid waste is classified as a RCRA hazardous waste on either of two bases. First, a solid waste is hazardous if it has been "listed" as a hazardous waste. EPA designates these RCRA "listed hazardous wastes" on a nationwide basis through a rulemaking process.[119] Second, a solid waste may be hazardous if it exhibits any of four hazard characteristics: ignitability, reactivity, corrosivity or toxicity.[120] EPA has established methodologies by which generators can determine if their solid wastes exhibit a characteristic, and generators are responsible for determining, on a waste-by-waste basis, whether their wastes are classified as a RCRA "characteristic" hazardous waste.[121]

At this point, fracking wastewaters have not been listed as a hazardous waste, and thus can only be classified as a RCRA hazardous waste if they exhibit one of the four hazard characteristics.[122] Available data do not indicate that fracking wastewater would exhibit the characteristics of ignitability, reactivity or corrosivity.[123] However, determining whether fracking wastewater exhibits the fourth "toxicity" characteristic ("TC") is more problematic. A solid waste exhibits the TC if it contains any of 40 specific constituents above defined regulatory levels.[124] In other words, a waste does not exhibit the TC because it contains toxic constituents or because it has adverse environmental effects.

119. 40 C.F.R. § 261.3(a)(2)(i) (2014).

120. *Id.*

121. *Id.* § 262.11 (2014).

122. *Id.* § 261.20 (2014).

123. *See* CLAUDIA ZAGREAN NAGY, CAL. DEP'T OF TOXIC SUBSTANCES CONTROL, OIL EXPLORATION AND PRODUCTION WASTE INITIATIVE 36 (2002), *available at* https://dtsc.ca.gov/HazardousWaste/upload/HWMP_REP_OilWastes.pdf. One report found that typical wastewater from the Marcellus Shale had a pH of 6, far from the requirements of the corrosivity characteristic defined at 40 C.F.R. § 261.22 (a pH of less than or equal to 2 or greater than or equal to 12.5) *See* TIMOTHY KEISTER, THE SCIENCE OF THE MARCELLUS SHALE: MARCELLUS HYDROFRACTURE FLOWBACK AND PRODUCTION WASTEWATER TREATMENT, RECYCLE, AND DISPOSAL TECHNOLOGIES 2 (2010), *available at* http://energy.wilkes.edu/PDF Files/Library/The_Science_of_Marcellus_Shale_Wastewater.pdf.

124. 40 C.F.R. § 261.24. (2014). If the waste being evaluated is a solid, the concentrations of constituents are measured, not in the waste itself, but in a liquid extract generated by use of the "toxicity characteristic leachate procedure" ("TCLP"). For liquid wastes, such as produced waters, the concentration of the toxic constituent would be measured after simply filtering the sample. *See* ENVTL. PROT. AGENCY, EPA PUB. NO. SW-846, *Toxicity Characteristic Leaching Procedure, Method 1311, in* TEST METHODS FOR EVALUATING SOLID WASTE, PHYSICAL/CHEMICAL METHODS," *available at* http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/1311.pdf.

It exhibits the TC only if it contains any of the 40 specific constituents above EPA's defined regulatory concentrations.

A review of the limited literature on the chemical constituents of produced water suggests that such water could be classified as a characteristic TC hazardous waste, if at all, based primarily on the presence of high levels of barium.[125] The literature suggests that some small portion of fracking wastewater contains concentrations of barium at levels above the regulatory threshold of 100 mg/liter.[126] Studies of the constituents of fracking wastewater indicate that the organic TC constituent associated with petroleum, benzene, and the inorganic constituents of lead, cadmium or mercury, are rarely found at concentrations high enough to exhibit the TC characteristic.[127]

125. *See, e.g.*, Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. 66,286-02 (2014); EPA TECHNICAL DEVELOPMENT DOCUMENT FOR CBM, *supra* note 44, at 3-11; CBM DETAILED STUDY REPORT, *supra* note 40 at 3-9–3-10; NAGY, *supra* note 123, at v, 36; KEISTER, *supra* note 123, at 2; SILVA, *supra* note 80, at 4–5 (2012); N.Y. STATE DEP'T OF ENVTL. CONSERVATION, PRELIMINARY REVISED DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM, Table 5.10 at 5-103 (2011), *available at* http://energyindepth.org/wp-content/uploads/marcellus/2011/07/SGEIS-Preliminary-Revised-Draft-7-1-11.pdf; CONRAD D VOLZ ET AL., CONTAMINANT CHARACTERIZATION OF EFFLUENT FROM PENNSYLVANIA BRINE TREATMENT INC., JOSEPHINE FACILITY: IMPLICATIONS FOR DISPOSAL OF OIL AND GAS FLOWBACK FLUIDS FROM BRINE TREATMENT PLANTS 7–8 (2011), *available at* https://ia600608.us.archive.org/6/items/ContaminantCharacterizationOfEffluentFromPennsylvaniaBrineTreatment/Josephine_V2_CHEC_2011.pdf; U.S. GEOLOGICAL SURVEY, WATER PRODUCED WITH COAL-BED METHANE 2 (2000), *available at* http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf; ROBERT KIMBALL, KEY CONSIDERATIONS FOR FRAC FLOWBACK/PRODUCED WATER REUSE AND TREATMENT 5 (2012), *available at* http://www.aaees.org/downloadcenter/Presentation-NJWEA052012-RobertKimball.pdf; *see also* REBECCA HAMMER & JEANNE VANBRIESEN, IN FRACKING'S WAKE: NEW RULES ARE NEEDED TO PROTECT OUR HEALTH AND ENVIRONMENT FROM CONTAMINATED WASTEWATER 2 (2012), *available at* http://www.nrdc.org/energy/files/fracking-wastewater-fullreport.pdf.

126. One study showed a "typical" analysis of wastewater from Marcellus shale gas production contained 6,500 mg/l of barium. KEISTER, *supra* note 123, at 2. Another presentation stated concentrations of barium in samples ranged from 7.75 to 4,300 mg/l. KIMBALL, *supra* note 125, at 7. It is not clear if these fracking samples were analyzed using the appropriate procedures under RCRA. The RCRA TC levels for solids are measured based on an extract derived using the TCLP, but, for liquid samples, the total concentration in the liquid is evaluated after simple filtration. The document from the Natural Resources Defense Council discussing the TC characteristic and fracking wastewater notes only that "[p]roduced water from the Marcellus formation has reported concentrations from non-detect to above the TCLP limit for barium (which is 100 mg/L)." *See* HAMMER & VANBRIESEN, *supra* note 125, at 62.

127. A California study, cited in the NRDC petition, found that "some" samples of produced water contained concentrations of benzene that exceeded the Toxicity Characteristic level of 0.5 mg/l (500 ug/l). NAGY, *supra* note 125, at 36. It is difficult to determine from the data presented in the report the number of samples that exceeded the

Despite the range of toxic constituents added to fracking fluids, it is unlikely that flowback would contain concentrations of any of the other 39 TC chemicals in excess of their regulatory thresholds.[128] Thus, with the exception of limited amounts of produced water containing high concentrations of barium, fracking wastewater is simply not likely to be classified as a RCRA characteristic hazardous waste.

Although removing the Oil and Gas E&P Waste Exclusion would place new obligations on generators to determine whether their wastes exhibit a hazard characteristic, this would have only limited significance.[129] In a small number of cases, removal of the exclusion would result in produced water being subject to hazardous waste requirements.[130] But given the likelihood that most fracking wastewater would not exhibit a hazard characteristic, an exclusive focus on the Oil and Gas E&P Exclusion seems misplaced. The effective application of regulatory requirements based on RCRA requires actions other than removal of the Oil and Gas E&P Waste Exclusion.

B. Options for Regulation of Fracking Wastewater as a Hazardous Waste

For RCRA to play a significant role in regulating fracking wastewater, the wastewater must first be classified as a hazardous waste. Although most fracking wastewater may not exhibit a hazard characteristic, EPA's criteria for listing wastes allow consideration of a variety of other factors relating to the toxicity and

regulatory criteria. There was wide variability in the samples (a reported standard deviation of almost 1,200) and the "median" number was 60.0 ug/l, almost 10 times below the TC threshold. The "mean" or average reported value was listed as 712.7 ug/l, which exceeds the threshold of 500 ug/l. But given certain extreme values detected, it is hard for this writer to determine the extent to which the mean value was affected by a limited number of extreme outliers. *Id.* at 17–35.

128. There appear to be limited data on the concentrations of the toxic constituents in flowback. *See* Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. at 66,296 ("EPA is not aware of any substantial sampling data on the presence or absence of these [fracking] additives in shale gas wastewaters."). However, when injected, chemical additives generally constitute only a few percent of the fracking fluid and the concentration of fracking chemicals in flowback would be even less.

129. RCRA does not contain mandatory testing requirements, and a generator may determine that its wastes are not hazardous based on its "knowledge of the processes used." 40 C.F.R. § 262.11 (2014). A generator that determined its wastes are not hazardous would violate RCRA Subtitle C requirements only if the wastes are, in fact, hazardous wastes.

130. *See supra* notes 122–27 and accompanying text.

environmental effects of the waste.[131] EPA has substantial discretion to determine whether to list a waste as hazardous,[132] and the existing data relating to the constituents of produced water and examples of mismanagement of the wastes might be sufficient to support a listing of produced water as a hazardous waste.

It seems unlikely that EPA would elect to list produced waters generated from all oil and gas exploration and production as hazardous wastes.[133] However, a hazardous waste listing could target fracking wastewater specifically by limiting the listing to "flowback," the initial produced water most likely to include fracking constituents. EPA could plausibly define flowback to include all wastewater generated within a certain time period, thirty days for example, from injection of fracking fluids.[134] Indeed, it might be easier, as a matter of data, policy and politics, to limit the listing to flowback.

Listing of either produced water generally or flowback specifically as a RCRA hazardous waste would subject the wastes to the full set of Subtitle C requirements. Among other consequences:

- Disposal wells receiving RCRA regulated hazardous wastewater would be required to meet the more stringent

131. 40 C.F.R. §261.11(a) (2014) (describing criteria for listing hazardous waste). The regulation lists three bases for listing a waste. A waste can be listed if it: (1) exhibits any hazardous waste characteristic, (2) it is "acutely hazardous" based on stringent risk assessment criteria, or (3) it contains any of a listed group of toxic constituents and EPA concludes that the waste is "capable of posing a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed." The subsection specifies a series of balancing factors to be assessed in making a listing determination, including factors relating to the waste's toxicity, plausible mismanagement scenarios, action taken by other government agencies or "other factors as may be appropriate." *Id.* Although wastes can be listed because they exhibit a hazardous waste characteristic, virtually all of the listed hazardous wastes were "listed" based on an assessment of the hazards posed by specific constituents in the wastes as provided in subsections (a)(2) and (a)(3). Only a limited number of wastes were listed because they exhibit a hazard characteristic. *See* 40 C.F.R. §§ 261.31–32 (2014) (designating, by "hazard code," the basis on which specific wastes were listed).

132. *See, e.g.*, Am. Petroleum Inst. v. EPA, 216 F.3d 50, 62 (D.C. Cir. 2000) (upholding listing of certain refinery wastes). On the other hand, some courts have required EPA to address in some detail the specific listing criteria and have assessed EPA's assertions that there is "plausible mismanagement" in the absence of listing. *See* Dithiocarbamate Task Force v. EPA, 98 F.3d 1394, 1404 (D.C. Cir. 1996).

133. This is an example of the rhetorical device of "litotes." Phrased another way, it will be a cold day in hell before EPA elects to list oil and gas wastes as hazardous. EPA has yet to respond to the petition by NRDC simply to remove the hazardous waste exclusion.

134. The largest portion of flowback is typically said to occur in the first 30 days of production of a gas well. *See supra* note 80 and accompanying text.

set of requirements that apply to Class I hazardous waste disposal wells;[135]

- POTWs receiving hazardous wastewater by truck or rail would be subject to some limited RCRA requirements applicable to hazardous waste Treatment, Storage and Disposal Facilities ("TSDFs");[136]
- CWTs receiving hazardous wastewater would be subject to RCRA TSDF permit requirements;[137]
- Hazardous wastewater transported by truck to POTWs or CWTs would be subject to RCRA manifest requirements;[138]
- Reuse/recycling of wastewater would raise significant RCRA issues; [139]

135. *See supra* note 56 for a discussion of the regulation of disposal wells under the SDWA.

136. Under the "domestic sewage exclusion" materials placed into a sewer system that is connected to a POTW are excluded from classification as a hazardous waste. *See* GABA & STEVER, *supra* note 103, § 5:3. Thus, a material might be a hazardous waste if dumped in the backyard, but excluded from classification as a hazardous waste if dumped into a municipal sewer. The discharge of wastes to POTWs through municipal sewers is largely regulated under the pretreatment program of the Clean Water Act. *See infra* Part V. Wastes transported to a POTW by truck or rail are not subject to the domestic sewage exclusion, and POTWs receiving hazardous wastes in this way are considered to be a RCRA TSDF. *See* GABA & STEVER, *supra* note 103, § 5:3. EPA has, however, provided that POTWs receiving hazardous wastes are generally subject to a "permit-by-rule" and do not need to obtain separate RCRA permits. The obligations for compliance generally are limited to meeting the POTW's NPDES permit limits and additional requirements to meet certain manifest, recordkeeping and reporting requirements. *See* 40 C.F.R. § 270.60(c) (2014).

137. EPA has not authorized CWTs to receive hazardous waste under a permit-by-rule, and a CWT receiving hazardous waste would need to obtain a RCRA Subtitle C TSDF permit. *Cf. id.* CWTs are, however, subject to different rules regarding modification of their RCRA permits. *See* ENVTL. PROT. AGENCY, EPA 821-B-01-033, : CENTRALIZED WASTE TREATMENT EFFLUENT LIMITATIONS GUIDELINES AND TREATMENT STANDARDS 3-2 (2001) [hereinafter SMALL ENTITY COMPLIANCE GUIDE, *available at* http://water.epa.gov/scitech/wastetech/guide/treatment/upload/2006_12_28_guide_cwt_CWTcompliance_guide.pdf.

138. As discussed above, the actual discharge regulated under a NPDES permit is excluded by statute and regulation from classification as a RCRA hazardous waste. *See supra* note 136 and accompanying text. Further, wastewater introduced to a POTW sewer system may also be excluded from classification as a hazardous waste. *Id.* This exclusion does not apply to wastewater transported to the POTW by truck, rail, or pipeline that does not include domestic sewage. *Id.*

139. Both the direct use of wastewater or the use of reclaimed wastewater in oil and gas production raises complex questions under EPA's RCRA provisions. *See generally* Jeffrey M. Gaba, *Solid Waste and Recycled Materials under RCRA: Separating Chaff from Wheat,* 16 ECOL. L.Q. 623, 628–29 (1989). Reclamation of wastewater prior to use creates variety of issues involving the status of the materials both before and after reclamation. *See, e.g.*, 40 C.F.R. § 261.2(a)(2)(ii), § 261.4(a)(23) (2014). Additionally, injection of wastewater for purposes other than disposal may fall within EPA's classification of use "constituting disposal" that is subject to its own limitations and rules. *Id.* § 266.20–23.

- Wastewaters would be subject to the requirements of the RCRA "land disposal restrictions;"[140]
- EPA's "derived-from" rule may affect options for management of sludges generated from treatment of fracking wastewaters;[141]
- Onsite management of fracking "hazardous waste," especially on-site evaporation, would be subject to new requirements under RCRA;[142] and,
- The "stigma" associated with management of hazardous waste would arise with uncertain consequences for options to manage and dispose of the wastes.[143]

Without doubt, listing fracking wastewaters as a hazardous waste would have far reaching consequences for the future of hydraulic fracturing in the United States. One of EPA's reasons for initially exempting oil and gas exploration and production wastes was its concern that regulation under Subtitle C would result in imposition of requirements that were "both extremely expensive and unnecessary for the safe management of oil and gas wastes."[144] At that time, EPA concluded that it "would be unable to craft a regulatory program to reduce or eliminate serious economic impacts of regulation under Subtitle C."[145]

EPA does, however, have authority under RCRA to regulate fracking wastewaters without imposing the full set of Subtitle C requirements. EPA has developed the concept of "conditional exclusion" to allow wastes that would otherwise be RCRA hazardous wastes to avoid both the stigma and regulatory consequences of full

140. *See* 40 C.F.R. pt. 268 (2014). Land disposal restrictions establish requirements that must be met before hazardous wastes may be disposed or introduced into wastewater treatment systems. *Id.* § 268.1.

141. The "derived-from" rule generally classifies pollution control sludges generated from treatment of a listed hazardous waste as a hazardous waste as well. *See* GABA & STEVER, *supra* note 103, § 2:57.

142. EPA's "accumulation" provisions limit on-site storage and treatment of hazardous wastes. 40 C.F.R. § 262.34 (2014). *See* GABA & STEVER, *supra* note 103, § 8:5. On-site reclamation of materials is subject to different requirements. *See* 40 C.F.R. §§ 260.34, 261.2(a)(2)(ii), 261.4(a)(23) (2014).

143. *See* Jeffrey M. Gaba, *Regulation by Bootstrap: Contingent Management of Hazardous Wastes Under the Resource Conservation and Recovery Act*, 18 YALE J. ON REG. 85, 114–15 (2001) (discussing significance of the hazardous waste "stigma" to EPA's regulatory scheme under RCRA).

144. *See supra* notes 103–06 and accompanying text.

145. *Id.*

regulation as a hazardous waste.[146] EPA has used the technique to establish tailored regulatory requirements for a variety of specific wastes based on EPA's assessment of conditions necessary to avoid "mismanagement" of the waste.[147] These requirements have included obligations relating to on-site management, recordkeeping, transportation and disposal.[148] Compliance with these tailored requirements results in the waste being excluded from classification as a hazardous waste.[149]

Conditional exclusion thus provides a mechanism for establishing enforceable management standards tailored to address specific environmental concerns associated with management and disposal of fracking wastewater. Through the device of conditional exclusion, EPA has authority to address environmental concerns documented, for example, through its current evaluation of the impact of fracking on drinking water.[150] Although "conditional exclusion" would allow EPA to establish a tailored regulatory scheme for fracking wastewater, the price of access to these reduced requirements is the initial classification of the wastewater as a hazardous waste. Unless a waste is otherwise classified as a hazardous waste, no exclusion—conditional or otherwise—is necessary. And for fracking wastewater, this necessary classification will only arise if EPA is willing to specifically list fracking wastewater as a hazardous waste.

IV. Regulation of the Discharge of Fracking Wastewater to Surface Waters Under the Clean Water Act

Significant quantities of fracking wastewater are managed by direct discharge to surface waters.[151] This discharge is largely authorized as a result of a series of EPA letters in the 1980s that

146. *See* Gaba, *supra* note 143, at 102.

147. *See id.* at 107–08.

148. EPA's conditional exclusion of hazardous waste sent off-site for reclamation by third parties contains a particularly detailed set of "conditional" requirements applicable to the generator, transporter, and reclaimer. *See* 40 C.F.R. § 261.4(a)(24) (2014)*; see also id.* § 261.4(a)(20) (listing detailed requirements that must be met to exclude hazardous secondary materials used to make fertilizer from classification as a solid waste).

149. *See* Gaba, *supra* note 143, at 105–06.

150. The purpose of this analysis is not to propose specific conditions, but to identify the legal authority available under RCRA to address environmental concerns with the management of fracking wastewater.

151. EPA has estimated that approximately 22 billion gallons of produced water are discharged annually to surface waters from CBM activities. *See* CBM DETAILED STUDY REPORT, *supra* note 40, at 3-15.

purported to exempt CBM wastewaters from an otherwise applicable national prohibition of the discharge of wastewaters from onshore oil and gas facilities. This section discusses EPA's regulation of fracking wastewaters under the Clean Water Act and the legality of the CBM exclusion. It also addresses issues associated with the development of site-specific limits on the direct discharge of fracking wastewaters based on "best professional judgment."

A. Regulation of the Direct Discharge to Surface Water under the Clean Water Act

The discharge of pollutants to surface waters is regulated under the federal Clean Water Act.[152] Under the CWA, all facilities that directly discharge pollutants into "navigable" surface waters, both private facilities and POTWs, are required to hold federally mandated National Pollutant Discharge Elimination System ("NPDES") permits.[153] States operating under an EPA approved permit program now issue most NPDES permits.[154]

NPDES permits generally contain "effluent limitations" that impose restrictions on the quantity or concentrations of pollutants that may be discharged.[155] These effluent limitations are established on one of two bases. First, all dischargers must meet "technology-based" limitations that are set based on an evaluation

152. 33 U.S.C. §§ 1251–52 (2012).

153. Clean Water Act § 301(a), 33 U.S.C. §1311(a); 33 U.S.C. § 1342. *See* ENVTL. PROT. AGENCY, EPA-K-833-10-001, NPDES PERMIT WRITER'S MANUAL 1–3 (2010) [hereinafter PERMIT WRITER'S MANUAL], *available at* http://water.epa.gov/polwaste/npdes/basics/ NPDES-Permit-Writers-Manual.cfm. The "direct discharge" of pollutants includes, for example, directly releasing pollutants into navigable waters from a pipe or ditch. Clean Water Act § 501(14), 33 U.S.C. § 1362(14). The scope of regulated "navigable waters" is subject to some uncertainty, but it includes waters that are navigable-in-fact, many tributaries to such waters, and in some cases nearby wetlands. *See* Rapanos v. United States, 547 U.S. 715 (2006).

154. Although EPA initially issued permits following adoption of the Clean Water Act in 1972, NPDES permitting responsibility may be delegated to States that have adopted state permit programs that are essentially equivalent to the federal program. Clean Water Act § 402(b), 33 U.S.C. § 1342(b)(2012). Virtually all states have been delegated authority to issue NPDES permits for sources within their borders. *See NPDES: Specific State Program Status*, ENVTL. PROT. AGENCY, http://water.epa.gov/polwaste/npdes/basics/State-Program-Status.cfm (last updated July 15, 2014). Delegation may, however, be partial, and Texas has been delegated authority to issue NPDES permits for most sources other than oil and gas operations. *Id.*

155. Effluent limitations for offshore oil and gas facilities are set as concentration-based rather than mass-based limits, due to the variability of the quantities of pollutants in the wastewater over the life of a well. *See* 40 C.F.R. pt. 435, subpt. C (2014).

of available control technology.[156] Congress initially established a technology-based "floor" based on "best practicable technology" ("BPT") to be met by all existing industrial sources for all pollutants.[157] Existing sources are now subject to more stringent limits based on "best available technology ("BAT") for toxic/non-conventional pollutants and "best conventional technology ("BCT") for a limited number of "conventional pollutants."[158] New sources, defined to include sources that commenced construction after promulgation of national standards, are subject to "new source performance standards" ("NSPS") representing "best available demonstrated technology" applicable to all pollutants.[159]

EPA has the authority to establish uniform, national technology-based limitations for categories and subcategories of sources.[160] In most cases, all facilities operating within an EPA defined subcategory must meet these national standards.[161] In the absence of national standards, permit writers may establish technology-based limitations on a case-by-case basis based on their "best professional judgment."[162]

In addition to technology-based limitations, NPDES permits may contain more stringent effluent limitations developed to ensure that discharges do not cause local receiving waters to exceed specific water quality standards.[163] These "water quality standards-based effluent limitations" ("WQBELs") are developed either on a case-by-case basis or derived from "total maximum daily loads" calculated for the body of water receiving the discharge.[164]

156. Clean Water Act § 301(a), 33 U.S.C. § 1342(a) (2012); 40 C.F.R. § 125.3(a) (2014).

157. Clean Water Act § 301(b)(1)(a), 33 U.S.C. § 1342(b)(1)(a). BPT limits were to have been met by July 1, 1977.

158. *Id.* § 301(b)(2). BAT and BCT limitations have a compliance date of March 31, 1989. The conventional pollutants are pH, biological oxygen demand, total suspended solids, fecal coliform, and oil and grease. 40 C.F.R. § 401.16 (2014).

159. Clean Water Act § 306, 33 U.S.C. § 1316(2) (2012).

160. *See* E.I. DuPont de Nemours v. EPA, 430 U.S. 112 (1977).

161. *Id.* at 122–23. There are a limited number of variances from compliance with national effluent limitations guidelines. *See* 40 C.F.R. § 125.73 (2014).

162. *See infra* notes 251–261 and accompanying text.

163. Clean Water Act § 301(b)(1)(C), 32 U.S.C. § 1311(b)(1)(C) (2012).

164. *See* Jeffrey M. Gaba, *New Sources, New Growth and the Clean Water Act,* 55 ALA. L. REV. 651, 658–62 (2004) (discussing the process of establishing WQBELs).

B. Technology-based Limits on the Direct Discharge from Fracking Sites

EPA has established a national effluent limitation for the "Onshore Subcategory" of the Part 435 "Oil and Gas Extraction Point Source Category."[165] The limitation, representing the "floor" BPT requirement, seems clear: the regulation states that "there shall be no discharge of wastewater pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand)."[166] This "zero discharge" requirement was first promulgated in "interim final" form in 1976,[167] and it was promulgated in final form in 1979.[168] The "zero discharge" requirement remains the currently applicable technology-based limitation for all new and existing facilities within the Onshore Subcategory.[169]

165. 40 C.F.R. pt. 435, subpt. C (2014).

166. 40 C.F.R § 435.32 (2014). The Onshore Subcategory includes most oil and gas activities located landward of the inner boundary of the territorial seas. 40 C.F.R. § 435.30 (2014). Several other subcategories, however, might include to a small number of fracking facilities. The Oil and Gas Extraction Point Source Category includes the "agricultural and wildlife water use subcategory" that allows the use of produced water for "agricultural or wildlife propagation" if the facility is located west of the 98th meridian, *id.* §§ 435.50–.52, and the "stripper subcategory" that applies to oil and gas facilities that produce less than ten barrels of oil per day. *Id.* § 435.60. The "coastal subcategory" applies to facilities operating "in or on" a water of the United States located landward of the inner boundary of the "territorial sea." 40 C.F.R. § 435.40 (2014). With the exception of facilities operating in Cook Inlet, Alaska, oil and gas facilities operating in the "coastal subcategory" are subject to the same "zero discharge" requirement for produced water applicable to facilities in the "Onshore Subcategory." *Id.* § 435.43. The other subcategory within the Oil and Gas category is the "offshore subcategory," which includes facilities operating seaward of the inner boundary of the territorial sea. *Id.* § 435.10 (2014). Issues associated with wastewater control from offshore facilities are not addressed in this article.

167. *See* 41 Fed. Reg. 44,942 (Oct. 13, 1976) ("interim final" limitations for the onshore segment of the Oil and Gas Category).

168. *See* Effluent Guidelines and Standards, Oil and Gas Extraction Point Source Category, 44 Fed. Reg. 22,069 (Apr. 13, 1979) (codified at 40 C.F.R. pt. 435) (final regulations for the onshore subcategory). EPA described the technology available for achieving zero discharge to include evaporation and, more commonly, injection into disposal wells. *See* ENVTL. PROT. AGENCY, EPA 440/1-76/055-A, DEVELOPMENT DOCUMENT FOR INTERIM FINAL EFFLUENT LIMITATIONS GUIDELINES AND PROPOSED NEW SOURCE PERFORMANCE STANDARDS FOR THE OIL & GAS EXTRACTION POINT SOURCE CATEGORY 85 (1976) [hereinafter 1976 DEVELOPMENT DOCUMENT], *available at* http://water.epa.gov/scitech/wastetech/guide/oilandgas/upload/O-G_DD_Int-Final_1976_EPA440-175-055a.pdf.

169. BPT limitations constitute a "baseline" or "floor" applicable to all existing sources, and, given a BPT limit of "zero discharge," there is no reason for EPA to adopt more stringent BAT/BCT or NSPS limitations. Since EPA has not promulgated an NSPS

1. Applicability of the Onshore Subcategory to Fracking Wastewater

The "Onshore Subcategory" includes facilities "engaged in the production, field exploration, drilling, well completion and well treatment in the oil and gas extraction industry which are located landward of the inner boundary of the territorial seas ."[170] Although the regulations do not define the "oil and gas extraction industry," EPA stated in the original 1976 Development Document that it studied oil and gas facilities falling within Standard Industrial Classification (SIC) Code 1311, "Crude Petroleum and Natural Gas" and SIC Code 1381, "Drilling Oil and Gas Wells."[171] EPA has also stated that the Oil and Gas category includes facilities falling within North American Industry Classification System (NAICS) codes 211111: Crude Petroleum and Natural Gas Extraction and 213111 213112: Drilling Support Activities for Oil and Gas Wells.[172]

limitation for the subcategory, all facilities are classified as "existing sources" regardless of when they are constructed. *See* Clean Water Act § 306(a)(2), 33 U.S.C. § 1316(a)(2) (2012).

170. *See* 40 C.F.R. § 435.30 (2014).

171. 1976 DEVELOPMENT DOCUMENT, *supra* note 168, at 8. The 1976 DEVELOPMENT DOCUMENT also stated that the Oil and Gas Industry included facilities operating in SIC Codes 382 ("Oil and Gas Field Exploration Services") and 1389 ("Oil and Gas Field Exploration Services, not classified elsewhere"). *Id.*; *see also* TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-213–214. SIC Code 1311 applies to:

> Establishments primarily engaged in operating oil and gas field properties. Such activities may include exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operation of separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. This industry includes the production of oil through the mining and extraction of oil from oil shale and oil sands and the production of gas and hydrocarbon liquids through gasification, liquid faction, and pyrolysis of coal at the mine site.

Occupational Safety & Health Admin., *Description for 1311: Crude Petroleum and Natural Gas*, https://www.osha.gov/pls/imis/sic_manual.display?id=387&tab=description (last visited Aug. 11, 2014).

172. TSD 2010 EG PROGRAM PLAN, *supra* note 42, at 10-1. NAICS Code 211111 ("Crude Petroleum and Natural Gas Extraction") replaced SIC Code 1311. NAICS Code 211111 applies to:

> Establishments primarily engaged in (1) the exploration, development and/or the production of petroleum or natural gas from wells in which the hydrocarbons will initially flow or can be produced using normal pumping techniques, or (2) the production of crude petroleum from surface shales or tar sands or from reservoirs in which the hydrocarbons are semisolids.

There is no doubt that facilities in the Onshore Subcategory engaged in the conventional production of natural gas are subject to the "zero discharge" requirement. Onshore facilities producing natural gas through fracking would also seem to fall directly within this category. However, EPA, relying on questionable factual bases and administrative procedures, has ignored the plain language of the scope of the Onshore Subcategory and imposed different regulatory requirements on fracking wastewater generated from shale gas, tight sandstone and, most significantly, CBM. EPA's treatment of wastewaters from these sources is described in turn.

a. Shale Gas

EPA has taken the position that the facilities fracking in shale formations fall within the "Onshore Subcategory" and are thus subject to the zero discharge requirement.[173] As noted above, the Onshore Subcategory applies to facilities "engaged in the production, field exploration, drilling, well completion and well treatment in the oil and gas extraction industry."[174] According to EPA, "[g]as drilling in the Marcellus Shale fits squarely within this applicability statement."[175]

EPA also claims that wastewater generated by fracking in shale formations was considered during development of the 1976 "interim final" and thus, presumably, the 1979 "final" regulations for the Onshore Subcategory. EPA justifies this conclusion by noting a reference in the preamble to the 1976 interim final regulations and several references in the 1976 Development Document to coverage of well treatment wastes from "hydraulic

U.S. Census Bureau, *211111: Crude Petroleum and Natural Gas Extraction*, http://www.census.gov/eos/www/naics/index.html (search "211111" in keyword field) (last updated Aug. 11, 2014). NAICS Code 213111 "Drilling Oil and Gas Wells" replaced SIC Code 1381 and consists of establishments "primarily engaged in drilling oil and gas wells for others on a contract or fee basis." U.S. Census Bureau, *213111: Drilling Oil and Gas Wells*, http://www.census.gov/eos/www/naics/index.html (search "213111" in keyword field) (last updated Aug. 11, 2014). EPA has stated that CBM production activities are likely to fall within NAICS Codes 211111 or 213111. *See* CBM DETAILED STUDY REPORT, *supra* note 40, at 3-30.

173. *See, e.g.*, Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. 66,286, 66,293 (Oct. 26, 2011) ("Unlike coalbed methane extraction, however, shale gas extraction is now subject to effluent guidelines for the Oil and Gas Extraction Point Source Category.").

174. 40 C.F.R. § 435.30.

175. Hanlon Memo, *supra* note 93, at 7.

fracturing."[176] The 1976 preamble does, in fact, mention hydraulic fracturing fluid as a possible waste from operations in the subcategory.[177] The 1976 Development Document describes hydraulic fracturing as one of the two most common methods to increase flow, and it describes both the process of hydraulic fracturing and the basic constituents of fracking fluid.[178] The 1976 Development Document also notes that fracking fluid is contained in wastewater and that some of the "initial production from the well[s] will contain some of these fluids."[179]

Although EPA justifies application of the Onshore Subcategory requirements to fracking in shale formations by references in the administrative record from 1976, fracking in shale did not develop on any scale until the 1980's, and there was certainly no domestic shale gas industry at the time of development of the Part 435 regulations.[180] Further, nothing in the 1976 Development Document suggests that EPA considered the cost or feasibility of zero discharge of produced water generated by fracking in shale formations or any other unconventional source of natural gas.[181] The references to hydraulic fracturing cited by EPA do not distinguish between fracking in conventional, shale, tight sandstone, or CBM formations. Indeed, the language in the Development Document describing hydraulic fracturing closely tracks a 1973 document prepared by the American Petroleum Institute ("API") cited in the Development Document.[182] Although the API document discusses hydraulic fracturing, it makes no specific reference to fracking in shale formations.

EPA's conclusion that shale gas production through fracking was properly considered during promulgation of Part 435 may be factually dubious, but there appears to be no dispute by the industry that production of shale gas is subject to this national zero

176. *Id.* (citing Interim Final Rule Making, 41 Fed. Reg. 44,942, 44,946 (Oct. 13, 1976) (to be codified at 40 C.F.R. pt. 435); 1976 DEVELOPMENT DOCUMENT, *supra* note 168, at 22–23, 96, 137).

177. Interim Final Rule Making, 41 Fed. Reg. at 44,946.

178. 1976 DEVELOPMENT DOCUMENT, *supra* note 168, at 22.

179. *Id.* at 23; *see also id.* at 96.

180. *See supra* notes 23–27 and accompanying text.

181. The administrative record of the 1976/1979 Effluent Limitations Guidelines is apparently not currently available. The Office of Environmental Information, EPA Docket Center advised the author that the record was not included in the docket collection. Email from Office of Environmental Information, EPA Docket Center, to author (Aug. 28, 2013) (on file with author).

182. AM. PETROLEUM INST., PRIMER OF OIL AND GAS PRODUCTION 17–18 (1973).

discharge limitation. Facilities engaged in fracking in shale formations have been subject to a zero discharge requirements for decades. The time is long past when the shale gas industry could challenge the application of this regulation.[183]

b. CBM

In contrast to its position on shale gas, EPA has concluded that fracking in coal beds to produce CBM is not subject to the requirements of the Onshore Subcategory.[184] It appears that EPA's first specific statement about the applicability of effluent limitations to fracking was made in 1982 in response to a request by the State of Alabama. Alabama was developing a "general permit" to apply to discharges from CBM activities, and it sought a determination from EPA that the Part 435 Oil and Gas Effluent Limitations Guidelines did not apply to wastewater from coal bed formations.[185] Alabama, as part of its request, stated that production of CBM was new and originated from safety efforts to reduce the risk of methane in coalmines. It noted that the 1974 oil embargo, deregulation and changes in gas pricing made the "collection and sale of this gas an attractive venture."[186] Alabama argued that Part 435 did not apply to the "coal bed degasification industry" since EPA had not studied the industry and thus had not considered the feasibility of zero discharge or the "specialized processes and the source and nature of the wastewater."[187]

EPA agreed. In a letter dated February 8, 1982, John Lum, Project Officer in EPA's Effluent Guidelines Division, replied briefly, stating simply that: "the U.S. Environmental Protection Agency did not consider the wastewater from such activities in

183. Under § 509(b) of the Clean Water Act, challenges to national effluent limitations guidelines must be brought within 120 days of their promulgation unless the challenge is "based solely on grounds which arose after such 120th day." Clean Water Act § 509(b), 33 U.S.C. § 1369(b) (2012).

184. *See* TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-232. As discussed below, CBM activities, although not subject to the national "zero discharge" requirement of the Onshore Subcategory, is still subject to regulation under the Clean Water Act. *See infra* notes 268–2734 and accompanying text.

185. Letter from Rodney D. Hames, Water Improvement Commission of the State of Alabama, to John Lum, EPA, January 19, 1982, *available at* www.regulations.gov (search for Docket Number EPA-HQ-OW-2006-0771-0979, p. 5–6).

186. *Id.*

187. *Id.* The Alabama letter did not argue or indicate that fracking to produce CBM involved specialized processes or differences in wastewater that distinguished fracking in coal beds from other forms of fracking.

development of the Oil and Gas Extraction Point Source Category; therefore Part 435 is not directly applicable to the coal bed degasification facilities."[188]

In a 1989 letter, Thomas O'Farrell, Director of the Industrial Technology Division at EPA referred to the 1982 Lum letter when he described EPA's "long-standing" position that the Part 435 onshore effluent guidelines did not apply to "coal bed production facilities."[189] The 1989 letter, mimicking Alabama's position, stated that Part 435 did not apply to coal bed production since

> [n]othing in the rulemaking record, including the technical, economic or environmental assessment support documents suggests that EPA considered any of these aspects of methane production from coal beds in developing the oil and gas extraction regulations at 40 C.F.R. Part 435. The existence of a domestic coal bed methane production industry was not known to the Agency during the development of the 1979 regulations for oil and gas extraction.[190]

The letter further stated that EPA did not consider technical issues or the "costs of compliance" with a zero discharge requirement, and stated that the Development Document "makes clear that only 'certain segments of the petroleum industry' were covered by the study."[191]

Neither the 1982 Lum letter nor the 1989 O'Farrell letter attempted to justify the exclusion of CBM based on a conclusion that CBM activities were different, either in their wastewater or available control options, from other covered oil and gas activities. Rather, the basis for EPA's exclusion is simply that EPA did not

188. Letter from John Lum to Rodney Hames, February 8, 1982, *available at* www.regulations.gov (search for Docket Number EPA-HQ-OW-2006-0771-0979, p. 4).

189. Letter from Thomas P. O'Farrell, Director, Industrial Guidelines Division, EPA, to Constance B. Harriman, Steptoe and Johnson, June 1, 1989, *available at* www.regulations.gov (search for Docket Number EPA-HQ-OW-2006-0771-0979, pp. 1–3).

190. *Id.* Although EPA claims that it was not aware of a "domestic coal bed production industry" at the time of promulgation of the regulations, substantial resources were being devoted in the 1970's to develop such an industry. *See supra* notes 24, 46–52, and accompanying text. The potential for development of commercial fracking in coal beds was hardly unforeseeable. Shale fracking was hardly more developed in the 1970's, and factors, including "oil shocks" and tax credits, that led to development of CBM also contributed to the explosive growth of shale gas after promulgation of Part 435. *Id.*

191. In fact, the "segments" of the industry referred to in the Development Document include those in SIC Codes 1311 and 1382. *See supra* note 171 and accompanying text. These segments include all production of natural gas and they are the same segments into which fracking in shale formations "fit squarely." *See* Hanlon Memo, *supra* note 93, at 7.

adequately consider the technological or economic issues associated with CBM when promulgating the Part 435 guidelines.

Since 1989, EPA has continued to state that Part 435 does not apply to CBM production.[192] There has been no additional analysis of its position excluding CBM production from coverage under the Onshore Subcategory, and it apparently continues to rely on the analysis in the 1989 O'Farrell letter for this position.[193]

c. Tight Sandstone Formations

Gas produced from tight sandstone formations constitutes a significant percentage of the total unconventional gas produced in the United States.[194] Like shale, it seems that production of tight sandstone gas fits "squarely" within the description of the Onshore Subcategory. Like CBM, however, production of tight sandstone gas is of relatively recent origin.[195] So what is EPA's position on application of the Onshore Subcategory zero-discharge requirement to tight sandstone gas?

EPA has clearly, if indirectly, stated that tight sandstone gas facilities are subject to Part 435 requirements. On its website, EPA states:

> For direct dischargers of unconventional oil and gas wastewaters from onshore oil and gas facilities – with the exception of coalbed methane – technology-based limitations are based on the Effluent Limitations Guidelines (ELGs) for the Oil and Gas Extraction Category (40 CFR Part 435).).[196]

Although EPA's position is clear, its rationale is less so. EPA has explained its position on the applicability of Part 435 to shale gas and CBM, but EPA has provided no explanation, other than the conclusory statement on its website, for its position on coverage of tight sandstone gas.[197]

192. *See, e.g.*, Notice of Final 2010 Effluent Guidelines Program Plan, 76 Fed. Reg. 66,286-02, 66,293 (Oct. 26, 2011).

193. *See, e.g.*, TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-232.

194. *See supra* note 39 and accompanying text.

195. *See supra* notes 34–39 and accompanying text.

196. Envtl. Prot. Agency, *Unconventional Extraction in the Oil and Gas Industry*, http://water.epa.gov/scitech/wastetech/guide/oilandgas/unconv.cfm (last updated Aug. 7, 2014).

197. A search of "tight sandstone" on EPA's website produces no documents addressing this issue.

2. Legality of EPA's Exclusion of CBM Activities from the Onshore Subcategory

EPA's exclusion of CBM facilities from coverage under the Onshore Subcategory raises troubling questions. Starting with the obvious, the regulatory provisions defining the scope of the Part 435 Onshore Subcategory clearly include fracking activities producing natural gas from shale, tight sandstone and coal beds; the express language and statement of coverage by description of SIC Code make this plain.[198] EPA itself stated that shale gas production "fits squarely" within the Onshore Subcategory.[199] EPA has also expressly stated that CBM production falls within the Part 435 Oil and Gas Extraction Point Category,[200] and with limited exceptions, facilities in this Category located "landward of the inner boundary of the territorial seas" expressly fall within the scope of the Onshore Subcategory.

Notwithstanding the fact that CBM activities plainly fall within the scope of the Onshore Subcategory, EPA has sought, through letters and guidance documents, to exclude CBM from the requirements of the subcategory. As described in greater detail below, EPA's action are unsupportable both on factual and procedural grounds.

a. Factual Inadequacy

EPA's basis for excluding CBM from coverage under the Onshore Subcategory was its conclusion that CBM activities were not considered as part of the 1979 rulemaking. But, as noted above, EPA's factual statements from which it draws this conclusion are questionable.[201] Statements in the O'Farrell letter that indicate EPA intended to cover only specific "segments" of the oil and gas industry are belied by the scope of study indicated in the

198. *See supra* notes 175–83 and accompanying text.

199. It does not appear that any public comment during the rulemaking process addressed the issue of the application of the regulation to fracking in unconventional sources. Further, judicial review was not sought challenging EPA's application of the scope of the subcategory, and no petition to revise the regulation to address the coverage of the subcategory was addressed by EPA.

200. *See, e.g.*, TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-232. If CBM falls within the Oil and Gas Category, by definition it falls within the express scope of the Onshore Subcategory which defines its applicability to include, with some exceptions, oil and gas activities located landward of the inner boundary of the territorial seas.

201. *See supra* notes 173–83 and accompanying text.

Development Document.[202] Further, the 1976 Development Document clearly indicates that EPA considered hydraulic fracturing in development of the Part 435 regulations, and nothing in the published administrative record supports a conclusion that EPA was distinguishing among the formations in which fracking occurred.[203]

Nor has EPA justified its differing treatment of wastewaters generated from other unconventional sources of natural gas. Although there was no "domestic coal bed methane production industry" in 1979, substantial resources were being devoted in the 1970s to development of CBM production.[204] The potential for development of commercial fracking in coal beds was foreseeable at the time of promulgation of the Part 435 regulations, and, in fact, a permit for CBM activities was sought within a year of promulgation of the regulations.[205] Fracking in shale or tight sandstone formations was hardly more developed in the 1970's, and factors, including "oil shocks" and tax credits, that led to development of the CBM industry also contributed to the explosive growth of shale gas after promulgation of the Part 435 regulations.

Finally, although it may be appropriate to exclude sources that are "fundamentally different" from the facilities assessed in establishing the subcategory,[206] nowhere did EPA justify its exclusion of CBM facilities from the Onshore Subcategory by noting differences in their wastewater characteristics, disposal options or costs.

There may be a justification for treating CBM facilities differently than other unconventional sources of natural gas, but EPA has not provided that explanation nor its factual basis.

202. *See supra* notes 167–68, 89–91 and accompanying text.

203. Even if the administrative record of the 1979 rulemaking did not include specific data on CBM activities, that fact alone would not be a basis for excluding CBM activities as EPA has done. *See supra* notes 184–93 and accompanying text. It appears impossible now to determine what, in fact, was included within this rulemaking record. *See supra* note 181.

204. *See supra* notes 46–49 and accompanying text.

205. *See supra* note 49 and accompanying text.

206. *See* Chemical Mfrs. Ass'n v. EPA, 870 F.2d 177, 214 (5th Cir. 1989) ("EPA is required to create a separate subcategory for a group of plants only when they are so fundamentally different from other plants on which the limitations are based that they cannot practicably achieve the effluent limitations achieved by the average of the best plants in the industry.").

b. Procedural Inadequacy

In its 1982 and 1989 letters, EPA simply stated that Part 435 does not "apply" or is "not applicable" to CBM activities.[207] EPA has never, however, disputed that CBM activities are included within the language defining the scope of the Onshore Subcategory, and it has not revised this language through notice and comment rulemaking.

If EPA's exclusion is seen as a revision of the legal scope of the Onshore Subcategory, EPA's process was clearly inadequate: revision of express provisions adopted through notice and comment rulemaking must generally be made through subsequent notice and comment rulemaking.[208] If EPA's action can, however, be characterized as an exercise of interpretation or discretion, its procedures might be defensible. There are a number of ways to characterize EPA's actions, but none justify EPA's method of excluding CBM activities from regulation under the Onshore Subcategory without properly revising the regulation.

c. Exercise of Agency Interpretative Authority

EPA's claim that Part 435 does not "apply" to CBM activities is perhaps best characterized as an agency interpretation of the scope of Part 435. An agency interpretation of its own regulation is certainly common and generally entitled to deference,[209] and the Supreme Court has stated that such deference applies "unless that interpretation is 'plainly erroneous or inconsistent with the regulation.'"[210]

And that is the problem with characterizing EPA's action as an exercise of its interpretative authority. EPA is simply not interpreting any ambiguity in the language defining the scope of Part 435. EPA is not, for example, claiming that the language of the applicability provisions of Part 435 or the language of the SIC codes that have described the scope of the category are sufficiently

207. *See supra* notes 185–90 and accompanying text.

208. *See, e.g.*, Nat'l Family Planning and Reprod. Health Ass'n, Inc. v. Sullivan, 979 F.2d 227 (D.C. Cir. 1992) (holding that a legislative rule is binding unless amended or repealed through notice and comment procedures).

209. *See* Kevin O. Leske, *Between* Seminole Rock *and a Hard Place: A New Approach to Agency Deference,* 46 CONN. L. REV. 227 (2013); Kevin M. Stack, *Interpreting Regulations,* 111 MICH. L. REV. 355 (2012).

210. *See* Decker v. Northwest Envtl. Def. Ctr., 133 S. Ct. 1326, 1337 (2013); Chase Bank USA v. McCoy, 131 S. Ct. 871, 880 (2011); Auer v. Robbins, 519 U.S. 452, 461 (1997); Bowles v. Seminole Rock & Sand Co., 325 U.S. 410, 414 (1945).

ambiguous to justify a conclusion that they do not include CBM activities.[211] The applicability provisions of the Onshore Subcategory are clear, explicit and simply need no interpretation.[212]

Alternatively, EPA's statements could be construed as a *post hoc* characterization of EPA's "original intent" when it promulgated the regulations.[213] In other words, EPA could be claiming that it could not have intended to include a form of industrial activity that did not exist when it promulgated the regulation. Note that EPA did not claim that Part 435 does not cover CBM activities because the factual record indicates that its processes and options for wastewater treatment are different from other onshore oil and gas activities.[214] Rather, EPA appears to be saying that CBM activities are not within the Onshore Subcategory solely because they were not in existence at the time of promulgation of the regulation.

EPA cannot, however, be generally claiming that effluent guidelines do not apply to an industrial process not in existence at the time of promulgation of the regulation. In such a case, of course, information could not have been included in the record regarding that process or activity, and claims that industrial processes were not previously in existence may justify the grant of a "fundamentally different factors" variance.[215] Indeed the Supreme Court has noted that the purpose of the variance is to "remedy categories which were not accurately drawn because information was either not available to or not considered by the Administrator in setting the original categories and limitations."[216] It would be a novel position for EPA to claim that activities, otherwise falling

211. EPA has expressly stated that CBM activities fall within the Oil and Gas Extraction Point Source Category, and most CBM activities fall within the geographically defined scope of the Onshore Subcategory. *See supra* notes 199–201 and accompanying text.

212. In other effluent limitations guidelines, the ambiguity of the scope of SIC codes has required EPA to interpret the appropriate scope of a subcategory. *See, e.g.*, Decker, 133 S.Ct. 132.

213. *See* Lars Noah, *Divining Regulatory Intent: The Place for a "Legislative History" of Agency Rules*, 51 HASTINGS L.J. 255 (2000) (discussing the role of an agency's "original intent" in judicial review of regulations).

214. *See supra* notes 184–93 and accompanying text. EPA, in fact, said it needed to study to see if there were such differences.

215. The "fundamentally different factors" variance allows a facility to get a different effluent limitation than would otherwise be applicable if it can demonstrate that there are factors affecting its operation that are "fundamentally different" from those considered by EPA when it established the national effluent limitations guidelines. *See* Clean Water Act § 301(n), 33 U.S.C. § 1311(n) (2012); 40 C.F.R. §§ 125.30–.32 (2014).

216. Chemical Mfrs. Ass'n v. Natural Res. Def. Council, 470 U.S. 116, 130 (1985).

within the scope of an existing effluent guideline, are exempt from the requirements of that subcategory simply by showing they were not in existence at the time of its promulgation.

Likewise, there are reasons to question EPA's "interpretation." As noted, in the 1970s there were indications of the development of the CBM industry that preclude an argument that EPA could not possibly have considered the industry.[217] Even more problematic is the fact that the exclusion for CBM activities was undertaken by an administration different from the one in place when the rule was promulgated. The rule was promulgated under President Carter, but narrowed by subsequent statements under President Reagan. Nothing, of course, prevents a new administration from revising a prior regulation based on its differing policy judgments, but such a change mandates a proper process.[218]

d. Exclusion of Legally Indefensible Regulations

Perhaps EPA's claimed exclusion is based on a view that application of the rule to CBM activities would be legally indefensible. Certainly, any failure of the administrative record to include data relating to CBM raises the concern that application of the regulations to CBM would be legally indefensible under an "arbitrary and capricious" standard.[219]

If EPA were to conclude that a rule was legally indefensible, there are mechanisms available to avoid its application. EPA can expressly alter or withdraw the offending provision through notice and comment or, if there is litigation, EPA can enter a judicially approved settlement or accept a judicial stay of the offending rule.[220] But in this case, EPA took none of these steps. In fact, EPA never justified excluding CBM based on an analysis of the legality of applying Part 435 to the newly developed process to produce CBM. Presumably, judicial review of the validity of application of the older regulation to new processes would hinge on whether the new processes were different in relevant respects from the factors that EPA considered in adopting the original regulation. However, EPA's exclusion of fracking in coal beds is not based on a reasoned

217. *See supra* notes 46–49 and accompanying text.

218. *See, e.g.*, Motor Vehicles Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 59 (1983).

219. *See id.*

220. *See* Jeffrey M. Gaba, *Informal Rulemaking by Settlement Agreement,* 73 Geo. L.J. 1241 (1985).

analysis of the differences between fracking in conventional or shale formations as contrasted with coal beds.

e. Exercise of Enforcement Discretion

Finally, EPA's statements may constitute an exercise of enforcement discretion. In other words, on finding inadequacies in the administrative record, EPA simply declined to apply Part 435 requirements to CBM activities. A determination by EPA that it will not enforce an otherwise applicable legal requirement is not unprecedented.[221] Although EPA's language, both in the letters and in later statements, implies an absolute exclusion of coverage rather than an exercise of discretion, such an exercise of enforcement discretion might be justifiable, and in fact, unreviewable.[222]

But if EPA's statements simply constitute an exercise of enforcement discretion, the "zero discharge" requirement of the Onshore Subcategory remains legally applicable to CBM facilities. Any NPDES permit that authorized discharge would violate the requirements of the Clean Water Act,[223] and the permit, whether issued by EPA or a state, would be vulnerable in an action for judicial review.[224] Similarly, states not applying the requirement in their permits would be vulnerable to a citizen petition seeking withdrawal of their NPDES permit program.[225]

At the very least, EPA's attempt to exclude CBM activities from the requirements of the Onshore Subcategory is suspect. If EPA wishes effectively to exclude CBM it must, through notice and comment rulemaking, revise the applicability language of the Onshore Subcategory and justify this revision with an adequate explanation supported by facts in the record.

221. *See, e.g.*, Monongahela Power Co. v. EPA, 586 F.2d 318, 320 (4th Cir. 1978) (discussing EPA's use of "extended compliance scheduling letters" as an exercise of enforcement discretion to extend otherwise applicable compliance deadlines).

222. *See* Heckler v. Chaney, 470 U.S. 821 (1985); *see also* Massachusetts v. EPA, 549 U.S. 497, 527 (2007) (noting that "in Heckler v. Chaney . . . we held that an agency's refusal to initiate enforcement proceedings is not ordinarily subject to judicial review.").

223. *See* 40 C.F.R. § 122.44(a)(1) (2014) (requirements for including promulgated effluent limitations in NDPES permits); 40 C.F.R. § 123.25 (2014) (requiring comparable requirements in state NPDES programs).

224. *See* Clean Water Act 509(b)(1)(F), 33 U.S.C. 1365(b)(1)(F) (2012) (providing for judicial review of federally issued NPDES permits); 40 C.F.R. § 123.30 (requiring comparable provisions authorizing judicial review of state issued permits).

225. *See* 40 C.F.R. § 123.25 (2014) (necessary elements of an approval state NPDES program); § 123.63 (criteria for withdrawal of state programs).

3. EPA Effluent Guidelines Actions for CBM

Valid or not, since 1982, EPA has taken the position that discharges from the production of CBM are not subject to any national, categorical effluent limitations guidelines. As early as 2004, EPA indicated that it would investigate development of effluent limitations guidelines for a potential new CBM Extraction Subcategory.[226] In 2010, EPA added CBM to the list of industries for which it planned to develop effluent limitations guidelines under its Effluent Guidelines Program Plan.[227]

In 2013, however, EPA proposed to abandon development of categorical standards for CBM.[228] EPA's rationale for declining to promulgate national technology-based standards for the CBM industry is quite remarkable. There appears no doubt that existing technology exists for the control of CBM wastewater discharge. EPA identifies reinjection and treatment through reverse osmosis as available technologies.[229] EPA's decision not to establish standards based on these technologies rests on the economic impact of applying national standards. In EPA's view, the declining price of natural gas resulting from the expanded production of shale gas means that the increased marginal costs of CBM production resulting from application of additional wastewater control would result in CBM extraction wells having a shorter operating lifespan and some CBM extraction not taking place at all.[230] In light of this economic impact, and without further discussion or analysis, EPA simply stated: "EPA's judgment at this time is that it should not move forward with additional regulation

226. TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-232. At that time, EPA concluded that it would not develop national technology-based standards for CBM, but rely instead on case-by-case limits. *Id.* at 5-245.

227. 76 Fed. Reg. 66,286 (2011). *See* CBM DETAILED STUDY REPORT, *supra* note 40; TSD 2010 EG PROGRAM PLAN, *supra* note 42, at Ch. 17. The Effluent Guidelines Program Plan was established pursuant to § 304(m) that requires EPA to publish a biennial plan to review and revise existing effluent limitations guidelines and promulgate new effluent limitations guidelines for unregulated categories that discharge toxic and unconventional pollutants. Clean Water Act § 304(m), 33 U.S.C. § 1314(m) (2012).

228. 78 Fed. Reg. 48,159 (2013). EPA's statements are unclear about whether it is proposing to discontinue development of "pretreatment standards" for CBM operators that send their wastes to POTWs.

229. See EPA TECHNICAL DEVELOPMENT DOCUMENT FOR THE CBM INDUSTRY, *supra* note 44.

230. *See* EPA ECONOMIC ANALYSIS OF CBM INDUSTRY, *supra* note 50, at 36. EPA evaluated the economic impact of establishing effluent limitations based on exchange or underground injection on existing and new CBM operations that directly discharge wastewater. It based its estimates of "profitability" on the current and projected price of natural gas. *Id.* at 3.

of wastewater discharges from CBM projects."[231] In its 2012 Effluent Guidelines Program Plan, EPA explained that: "[I]t appears that EPA may not be able to identify a wastewater treatment technology that would be economically achievable for this industrial subcategory."[232]

Several things are noteworthy about EPA's decision. First, every imposition of control technology comes at some economic cost, and EPA has considerable discretion in assessing the significance of these costs.[233] EPA never explains why, in the case of CBM activities, the costs it identifies make control technologies unachievable. Certainly it never explains how the economic impact of effluent limits, in terms of reduced gas production, would be greater for CBM than it is for shale.[234] Second, EPA never states that technology-based limits for CBM are actually "unachievable." It simply states its judgment "not to move forward" on developing national guidelines because it "appears" that that it "may not be able" to identify achievable technology. Finally, CBM operations that result in the direct discharge of wastewater remain subject to technology-based effluent limitations developed based on "best professional judgment." As discussed below, it is unclear what impact EPA's vague statements have on these BPJ decisions.[235]

C. Technology-based Limits on the Discharge of Fracking Wastewater from Centralized Waste Treatment Facilities

Although wastewater from fracking in shale formations may not be directly discharged, that same wastewater may be discharged if the facility sends the wastewater for off-site treatment at a privately owned treatment facility. Private facilities that treat wastes generated from off-site sources are, under EPA's nomenclature, classified as "centralized waste treatment" ("CWT") facilities, and

231. *Id.*

232. ENVTL. PROT. AGENCY, EPA-821-R-12-002, PRELIMINARY 2012 EFFLUENT GUIDELINES PROGRAM PLAN, 1–2 (2013), *available at* http://water.epa.gov/scitech/wastetech/guide/304m/upload/Preliminary-2012-Effluent-Guidelines-Program-Plan.pdf.

233. *See, e.g.*, National Wildlife Fed'n v. EPA, 286 F.3d 554 (D.C. Cir. 2002); Rybachek v. EPA, 904 F.2d 1276 (9th Cir. 1990); Weyerhaeuser Co. v. Costle, 590 F.2d 1011 (D.C. Cir. 1978).

234. Shale gas may be profitably extracted at lower gas prices than CBM, but increased costs based on the "zero discharge" requirement have presumably caused some marginal shale gas wells not to be drilled and for shale gas wells to have a shorter operating life.

235. *See infra* notes 268–289 and accompanying text.

EPA has established separate Part 437 effluent limitation guidelines for the Centralized Waste Treatment Point Source Category.[236]

Although a significant amount of fracking wastewater is sent to CWTs,[237] the extent to which CWTs themselves directly discharge fracking wastewater is less clear. Some fracking wastewater sent to a CWT is treated and returned for reuse at the well.[238] Additionally, many CWTs do not directly discharge the treated waste, but send the waste for further treatment at a POTW.[239] EPA has stated that 90 percent of CWTs that receive fracking wastewater send their wastes to POTWs.[240] EPA has established separate pretreatment standards applicable to facilities within the CWT category.

CWTs that directly discharge into surface water are subject to a complex set of requirements. The initial question is whether the requirements of the CWT Point Source Category apply at all. The CWT effluent limitation guidelines were intended to apply to facilities that treat variable wastes generated by differing industrial categories,[241] and EPA has established important exclusions that limit their applicability. First, CWTs that only treat wastewater generated by facilities in the same industrial subcategory are not subject to CWT requirements.[242] In other words, if a facility treats only fracking wastewater, even if some of the wastewater was generated off-site, the facility would not be subject to regulation under the CWT category. Second, facilities that treat off-site wastes transported to the facility through a dedicated conduit, such as a pipeline, are also generally not subject to CWT requirements.[243] In EPA's view, wastewater transported via a dedicated pipeline tends to be more consistent in composition and thus are not appropriately regulated under the CWT requirements. In effect,

236. 40 C.F.R. § 437 (2014).

237. *See* 76 Fed. Reg. 66,286-02, 66,296 (2011) (90% of shale gas wastewater treated at CWTs is sent to POTWs.).

238. *See* CNTY OF LYCOMING, PA., THE IMPACTS OF THE MARCELLUS SHALE INDUSTRY ON WATER, SEWER AND STORMWATER INFRASTRUCTURE IN LYCOMING COUNTRY, 35 (2012), *available* at http://www.lyco.org/Portals/1/PlanningCommunityDevelopment/Documents/Water%20Study--Commissioner%20Approved%2030%20Auguszt%202012.pdf.

239. *See supra* notes 90–97 and accompanying text. CWTs sending wastes to POTWs are subject to the same requirements as other indirect dischargers. 40 C.F.R. § 437.3.

240. *See* SMALL ENTITY COMPLIANCE GUIDE, *supra* note 137, at 3-1. EPA repeated this statistic in a 2011 discussion of its plan to develop effluent guidelines for CBM. 76 Fed. Reg. at 66,296 (2011).

241. *See* 64 Fed. Reg. 2280, 2293 (1999).

242. 40 C.F.R. § 437.1(b)(2) (2014).

243. *Id.* § 437.1(b)(3).

then, the specific CWT effluent limitations only apply to private facilities that directly discharge treated wastes from off-site sources if: (1) the off-site sources are in different industrial subcategories; and, (2) the waste is transported to the CWT by truck, rail or other "non-dedicated" conduit.

The CWT Point Source Category has four subparts, and determining which subpart applies presents its own difficulties.[244] EPA has identified the appropriate subpart for wastes from certain specified industrial sources. If wastes come from these specified sources, determining the applicable CWT subpart is simple. For wastes from unspecified sources, including fracking wastewater, determining the applicable subpart is far more difficult. EPA has provided "guidance" that suggests application of a Subpart should be based on the concentrations of "oil and grease" and certain metals in the waste.[245] This guidance - but not the regulations themselves – states that the "Organics" Subpart should be applied in those cases where a waste does not fit the criteria for inclusion in the Oil or Metals Subpart.[246]

Determination of which CWT subpart applies to CBM wastes may thus involve a waste-specific assessment of the concentrations of oil and grease and metals in the waste. EPA has specifically stated that wastewater generated from fracking in the Marcellus Shale do not fall within the criteria for inclusion in the "Oils" or "Metals" subparts and therefore should be regulated under the "Organics" subpart.[247] EPA notes, however, that this determination is based solely on data from Marcellus Shale fracking wastewater, and the applicable CWT subcategory might be different for other fracking wastewaters.[248]

244. In fact, the application of the subparts is so ambiguous that EPA says to use "common sense" in making a determination. SMALL ENTITY COMPLIANCE GUIDE, *supra* note 137, at 5-3. CWTs receiving wastes from multiple CWT subcategories have two choices. They may choose to meet the effluent limitations applicable to each subcategory, but this may involve segregating the waste streams and separately monitoring and treating each waste stream prior to their commingling. Alternatively, the facility may request development of a case-by-case set of effluent limitations under the provisions of the "multiple waste stream" subcategory. 40 C.F.R. § 437.40. This will allow the CWT to commingle the waste streams before treatment and be subject to monitoring and effluent limitations at a single discharge point. Permit writers set these effluent limitations at levels that achieve "equivalent treatment" required for the individual subcategories. *Id.* § 437.40(a).

245. *See* SMALL ENTITY COMPLIANCE GUIDE, *supra* note 137, at 5-5.

246. *Id.*

247. *See* Hanlon Memo, *supra* note 93, at 12.

248. *Id.*

D. Developing Site-Specific Technology-Based Limitations Based on "Best Professional Judgment"

Under EPA's existing regulations, fracking wastewater from CBM activities and fracking wastewater discharged from CWT facilities or POTWs are not subject to the Part 435 "zero discharge" requirement. The discharge of these wastewaters is limited only by specific permit limitations that are imposed in their NPDES permit. The need for NPDES permit limits on pollutants from these sources is particularly important since, under the "permit shield" provision of the Clean Water Act, pollutants not specifically limited in a permit may be discharged without constraint.[249] As long as the permittee adequately discloses the pollutants in its wastewater, the permittee may legally discharge pollutants not limited in its permit.[250]

Although all NPDES permits should include site-specific permit limitations that assure compliance with water quality standards, the process of establishing Water Quality-based Effluent limitations (WQBELs) is confused.[251] WQBELs are an important but uncertain basis for regulating the discharge of fracking wastewater.[252]

249. Under § 402(k), the "permit shield" provision of the CWA, compliance with a permit is deemed compliance with the Act. Clean Water Act § 402(k), 33 U.S.C. § 1342(k) (2012).

250. *See, e.g.,* Piney Run Pres. Ass'n v. County Comm'rs, 268 F.3d 255 (4th Cir. 2001) (holding "that the Commissioners did not violate the Clean Water Act because (1) they complied with the discharge limitations and reporting requirements of their permit, and (2) their discharges of heat were within the reasonable contemplation of the permitting authority at the time the permit was issued.").

251. All NPDES permits are required to contain limitations to ensure that the discharge does not cause in-stream conditions to violate applicable water quality standards. Clean Water Act § 301(b)(1)(C), 33 U.S.C. § 1311(b)(1)(C) (2012); 40 C.F.R. § 122.44(d) (2014). Water Quality-Based Effluent Limitations ("WQBELs") are only established if the discharge, after meeting technology-based limits, might still violate local water quality standards, including any in-steam numerical criteria for specific pollutants or the state's "anti-degradation" requirement. *See* 40 C.F.R. § 122.44(d). By definition, WQBELs are site-specific and are more stringent than technology-based requirements. Since fracking facilities producing shale gas are subject to a "zero discharge" requirement, WQBELs would not apply. However, fracking facilities directly discharging CBM wastewater and CWTs or POTWs receiving any fracking wastewater may be subject to WQBELs. The process for determining a WQBEL for a facility is, however, one of the most confusing parts of the CWA. *See* Gaba, *supra* note 164, at 548–662. In some cases, WQBELs are derived from the "total maximum daily loads" and "waste load allocations" established by a state for a given stream segment. *Id.* at 658–59. Additionally, WQBELs can be set on a case-by-case basis by the permit writer to ensure that water quality criteria are not violated. *See* ENVTL. PROT. AGENCY, TECHNICAL SUPPORT DOCUMENT FOR WATER QUALITY-BASED TOXICS CONTROL 67 (1991), *available at* http://water.epa.gov/scitech/swguidance/standards/handbook/upload/2002_10_25_npdes_pubs_owm0264.pdf. Anti-degradation provisions included in all state water quality standards also provide a basis for limiting the discharge of pollutants into streams,

The Clean Water Act does, however, contain additional authority that authorizes permit writers to develop specific technology-based limitations on pollutants in fracking wastewater based on "best professional judgment" ("BPJ").[253] BPJ limits are not a distinct class of limitations; rather they involve an exercise of the permit writer's judgment in establishing permit limits that represent BPT/BAT/BCT/NSPS for the facility.[254] In developing BPJ limits, permit writers must consider the same factors that would be assessed in establishing national, categorical standards, including a consideration of the available control technologies and their cost of use.[255] In other words, BPJ limits constitute a permit writer's assessment of BPT/BAT/BCT/NSPS limits for the specific discharger.

and the process of establishing WQBELs to satisfy a state "anti-degradation" requirement is perhaps even more confusing. *See* Gaba, *supra* note 164, at 671–88.

252. There do not appear to be any distinct legal issues in establishing WQBELs in NPDES permits for discharges of fracking wastewater. Narrative and numerical criteria and anti-degradation provisions can all form the basis for establishing specific effluent limits on pollutants from all fracking wastewater. *See* ENVTL. PROT. AGENCY, EPA-823-B-94-005A, WATER QUALITY STANDARDS HANDBOOK: SECOND EDITION, 3.5 FORMS OF CRITERIA (1994), *available at* http://water.epa.gov/scitech/swguidance/standards/handbook/index.cfm. Although narrative criteria can form the basis for WQBELs, development of WQBELs may be more difficult for pollutants for which the state has not established specific numerical criteria. In *Pennaco Energy Co. v. EPA*, 692 F. Supp. 2d 1297 (D. Wyo. 2009), the court rejected EPA's approval of specific numerical criteria for EC and SAR established by Montana to address problems from CBM discharge. The establishment of specific numerical standards for these parameters was complicated by the fact that seasonal variation exceeded the specific limits established by the State. *Id.* at 1311. The court held, among others things, that EPA had not justified its approval of the standards. *Id.* at 1310–13.

253. Clean Water Act § 402(a)(1)(A) requires permits to include applicable requirements of the Act, including effluent limitations required under §§ 301 and 306. Additionally, § 402(a)(B) provides that "prior to the taking of necessary implementing actions relating to all such requirements," permits may include "such conditions as the Administrator determines are necessary to carry out the provisions of this Act." EPA has codified its authority to impose case-by-case permit-specific BPJ limits under § 402(a)(1)(B) at 40 C.F.R § 125.3(c)-(d).

254. Adjustments to the technology-based "secondary treatment" standards applicable to POTWs are more limited and generally only include limits on Total Suspended Solids ("TSS") or Biological Oxygen Demand ("BOD"). *See* NPDES PERMIT WRITER'S MANUAL, *supra* note 153, § 5.1. BPJ can be used to establish mass-based limits on BOD and TSS. *See In re* City of Port St. Joe & Florida Coast Paper Co., 7 E.A.D. 275, 292–93 (EAB 1997). More stringent limits in POTW permits, including limitations on pollutants not addressed in POTW technology-based secondary treatment limits, may be established to ensure compliance with water quality standards. *See, e.g.*, *In Re* Scituate Wastewater Treatment Plant, 12 E.A.D. 708 711–13 (EAB 2006).

255. 40 C.F.R. § 125.3(d) (2014). *See* Natural Res. Def. Council v. EPA, 863 F.2d 1420 (9th Cir. 1988).

EPA authorizes permit writers to set BPJ limits for industrial sources in two circumstances. First, permit writers may set BPJ limits if there are no promulgated national standards applicable to the permittee.[256] This would be the basis for establishing BPJ limits on the discharge from CBM facilities.[257] Second, where national limitations are applicable, permit writers can set BPJ limits, in some cases, for pollutants not specifically regulated under the national standards.[258] This could form the basis for imposing additional technology-based limits on the discharge of fracking wastewater from CWT facilities.[259]

Although it is clear that BPJ limits are to be based on the same statutory factors considered in setting national effluent limitations guidelines, the actual process for establishing BPJ limits is somewhat opaque. In its 2010 NPDES Permit Writer's Manual, EPA states that BPJ limits should be established for "pollutants of concern."[260] The Manual lists the statutory factors to be considered in setting BPJ limits and states generally that BPJ limits should be based on: (1) the appropriate technology for the category class of point sources of which the applicant is a member, based on all available information; and, (2) any *unique* factors relating to the applicant.[261] The generality of this guidance creates substantial uncertainty about the scope of BPJ limits that may be included in permits for direct discharges from CBM activities or from CWT facilities.

1. BPJ for CBM

Although EPA states that the Part 435 national categorical standards do not apply to CBM activities, it has consistently stated that permit writers may include BPJ limits in NPDES permits for

256. 40 C.F.R. § 125.3(c)(2). *See* PERMIT WRITER'S MANUAL, *supra* note 153, at 5-45–5-46. In some cases, the preamble to promulgated effluent limitations guidelines provides information about establishing BPJ limitations for discharges not covered by the guideline. *See, e.g.*, *In re* Goodyear Tire & Rubber, Co., 4 E.A.D. 670, 677 (EAB 1993).

257. *See infra* notes 262–289 and accompanying text.

258. 40 C.F.R. § 125.3(c)(3) (authorizing the development of case-by-case permit and stating "[w]here promulgated effluent limitations guidelines only apply to certain aspects of the discharger's operation, or to certain pollutants, other aspects or activities are subject to regulation on a case-by-case basis in order to carry out the provisions of the Act.").

259. *See infra* notes 290–303 and accompanying text. EPA suggests a more limited basis for establishing additional technology-based limits for POTWs. *See supra* note 253.

260. PERMIT WRITER'S MANUAL, *supra* note 153, at 5-45.

261. *Id.* at 5-46 (emphasis added).

CBM facilities that directly discharge.[262] EPA regulations and case law suggest that, in the absence of nationally promulgated effluent limitations guidelines, development of BPJ limits is mandatory.[263] In *Northern Cheyenne Tribe v. Montana Dept. of Envtl. Quality,*[264] the Supreme Court of Montana specifically held that CBM permits *must* contain permit-specific BPJ limits.

There is no dispute that control technology is both available and widely employed in the CBM industry, and BPJ limits on CBM discharges have been developed and included in NPDES permits.[265] In 2001, EPA Region 8 began to develop guidance on establishing BPJ limits for CBM activities.[266] That exercise ended without public explanation and not even drafts of any proposed guidance remain available on the Internet.[267] A variety of other actors have also proposed CBM BPJ limits.[268]

262. *See* Hanlon Memo, *supra* note 93, at 11; TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-232. In its NPDES Permit Writers' Manual, EPA specifically refers to CBM activities in its description of circumstances where permit writers can set BPJ limits:

> When effluent guidelines are available for the industry category, but no effluent guidelines are available for the facility subcategory (e.g., discharges from coalbed methane wells are not now regulated by effluent guidelines; however, EPA considers the coalbed methane industrial sector as a potential new subcategory of the existing Oil and Gas Extraction point source category [Part 435] because of the similar industrial operations performed [i.e., drilling for natural gas extraction]).

PERMIT WRITER'S MANUAL, *supra* note 153, at 5-45.

263. EPA permit regulations specifically require permits to contain technology-based limitations, 40 C.F.R. § 125.3(a) (2014) and specify BPJ as a means of imposing these requirements. *Id.* § 125.3(c). In *Texas Oil and Gas Assn v. EPA,* 161 F.3d 923, 928–29 (5th Cir. 1998), the Fifth Circuit stated that, in the absence of a national guideline, "EPA *must* determine on a case-by-case basis what effluent limitations represent the BAT level, using its "'best professional judgment.'" (emphasis added).

264. Northern Cheyenne Tribe v. Mont. Dept. of Envtl. Quality , 234 P.3d 51 (Mont. 2010).

265. *See* CBM DETAILED STUDY REPORT, *supra* note 40, at 2-5–2-7 (data on NPDES discharge monitoring requirements in NPDES permits issued for CBM discharges).

266. *See* EPA Region 8, "Best Professional Judgment" (BPJ) Determination of Effluent Limitations that Represent Best Available Technology Economically Achievable (BAT) for Coalbed Methane (CBM) Activities; Announcement of a Meeting, 66 Fed. Reg. 46455-01 (2001).

267. One commentator stated that the project was "shelved and never completed." Rebecca W. Watson, *Coalbed Natural Gas Produced Water Handling: New Challenges for a Key Issue,* LEXOLOGY (Aug. 8, 2007), http://www.lexology.com/library/detail.aspx?g=32df57c0-0506-4b43-930e-9ac62054878c.

268. *See, e.g.,* JAMES R. KUIPERS, DRAFT: TECHNOLOGY-BASED EFFLUENT LIMITATIONS FOR COAL BED METHANE-PRODUCED WASTEWATER DISCHARGES IN THE POWDER RIVER BASIN OF MONTANA AND WYOMING (2004), *available at* http://s3.amazonaws.com/zanran_storage/www

Since BPJ limits *must* be imposed on the direct discharge from CBM activities, how should permit writers establish such limits? In 2004, EPA specifically discussed the bases for establishing BPJ limits for CBM permits:

> NPDES permit writers can develop BPJ limits by using one of two different methods. A permit writer can either transfer numerical limitations from an existing source such as from a similar NPDES permit or an existing set of effluent guidelines, or derive new numerical limitations.[269]

Whatever the basis for the specific numbers, the permit writer would presumably need to determine that the numbers were "achievable" by the permittee.[270]

The most obvious approach to establishing BPJ limits in a CBM permit is to transfer the requirements from the effluent limitations applicable to the Onshore Subcategory of the Oil and Gas Extraction Point Source Category.[271] As discussed above, most onshore oil and gas activities, including all fracking other than in coal bed formations, are subject to a BPT effluent limitation of "zero discharge."[272] Although it seems logical to transfer this requirement to CBM permits, EPA has indicated that the existing "zero discharge" requirement applicable to the Onshore Subcategory may not be economically achievable by CBM facilities.[273] This certainly suggests that the requirements of the

.northernplains.org/ContentPages/16689210.pdf; Note, Julie Murphy, *Coal Bed Methane Wastewater: Establishing a Best Available Technology Standard for Disposal under the Clean Water Act*, 14 SOUTHEASTERN ENVTL. L.J. 333 (2006). In 2001, EPA Region 8 began to develop guidance on establishing BPJ limits for CBM activities. *See* EPA Region 8, "Best Professional Judgment" (BPJ) Determination of Effluent Limitations that Represent Best Available Technology Economically Achieveable (BAT) for Coalbed Methane (CBM) Activities; Announcement of a Meeting, 66 Fed. Reg. 46,455-01 (Sept. 5, 2001). That exercise ended without public explanation and not even drafts of any proposed guidance remain available on the internet. One commentator stated that the project was "shelved and never completed." *See* Watson, *supra* note 267.

269. TSD 2004 EG PROGRAM PLAN, *supra* note 76, at 5-232.

270. *See infra* notes 277–289 and accompanying text.

271. It is possible that Effluent Limitations Guidelines for the Coal Mining Point Source Category might be relevant in establishing BPJ limits for CBM activities. 40 C.F.R. § 434 (2014). EPA has stated, however, that CBM activities are properly considered to be part of the Oil and Gas Point Source Category and that "EPA did not consider CBM production in developing the coal mining effluent guidelines." 2004 TSD EG PROGRAM PLAN, *supra* note 76, at 5-232.

272. *See supra,* notes 165–69, and accompanying text.

273. *See supra*, notes 228–235, and accompanying text.

Onshore Subcategory cannot simply be imposed on CBM discharges. EPA has also suggested that development of BPJ limits requires a case-by-case assessment and does not involve application of an "absolute" national standard.[274]

If national guidelines are not directly transferrable to CBM activities, permit writers must "derive new numerical limitations" on a site-specific basis.[275] There is extensive information about the pollution control equipment currently available for discharges from CBM activities,[276] and the most significant issue may be the role of site-specific cost considerations in developing BPJ limits.

EPA has, however, provided limited guidance on the role of site-specific cost issues in setting BPJ limits.[277] The NPDES Permit Writer's Handbook is silent, saying simply that statutory factors, which include "cost," are to be assessed in setting BPJ limits.[278] A 1976 opinion of EPA's Office of General Counsel states that in assessing costs in BPJ states:

> [T]he Regional Administrator must weigh the "internal" and "external" costs of effluent reduction against the effluent reduction achieved, and that "the resolution of that process is, of course, a

274. *See In re* Dominion Energy Brayton Point, L.L.C. (Formerly Usgen New England, Inc.) Brayton Point Station, 12 E.A.D. 490, 607–08 (E.P.A. 2006).

275. Although EPA suggests that BPJ limits can be transferred from another existing NPDES permit, this does not seem a distinct alternative. If a permit writer chose to transfer permit limits from another permit, the permit writer would presumably still have to justify the application of those numbers to the specific permit under consideration. *See* American Iron & Steel Inst. v. EPA, 526 F.2d 1027, 1061–64 (3d Cir. 1975)

276. *See, e.g.*, ENVTL. PROT. AGENCY, EPA-820-R-13-009, TECHNICAL DEVELOPMENT DOCUMENT FOR THE COALBED METHANE (CBM) EXTRACTION INDUSTRY, 4-1–4-36 (2013).

277. In 1980, EPA stated that it was "considering" establishing guidance on assessing economic achievability in establishing BPJ limits. No such guidance appears to have been issued. Memorandum from R. Sarah Compton, Writing NPDES BAT Permits in the Absence of Promulgated Effluent Guidelines (1980), *available at* http://www.epa.gov/npdes/pubs/owm558.pdf.

278. PERMIT WRITER'S MANUAL, *supra* note 153 at 5-46. The 2010 Permit Writer's Handbook refers to a 1982 "Protocol" and "Workbook" for establishing "Economic Achievability" in NPDES Permits." *Id.* at 5-48. *See* PUTNAM, HAYES & BARTLETT, PROTOCOL FOR DETERMINING ECONOMIC ACHIEVABILITY FOR NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMITS (1982), *available at* www.epa.gov/npdes/pubs/protocol_npdespermits.pdf; Putnam, Hayes & Bartlett, Work Book for Determining Economic Achievability for National Pollutant Discharge Elimination System Permits (1982), *available at* http://www.epa.gov/npdes/pubs/workbook_econ_permits.pdf. The Protocol clearly describes a "two step" process in assessing achievability based either on the impact of the costs at the "firm" or "facility" level, and the Workbook states: "While the EPA has not defined economically achievable (EA), pollution control technologies are said to be economically achievable in this study if their use would not cause the plant to shut down." *Id.* at ch. 1.

> matter within the sound discretion of the Regional Administrator: it is not a matter of law.[279]

EPA further stated that the permit writer "must exercise that discretion in a reasoned manner, considering all pertinent evidence before them, and in light of the purpose, provisions, and legislative history of the Federal Water Pollution Control Act."[280]

The role of site-specific cost factors in setting BPJ limits raises a number of issues. First, may BPJ limits be set at levels that are not economically achievable by the permittee?[281] Congress contemplated that effluent limitations would be uniformly applied to all sources within an industrial subcategory regardless of an individual sources' economic ability to comply.[282] National effluent limitations guidelines are set at levels that will force some facilities within a subcategory to close because those facilities cannot afford to comply.[283]

Even a requirement to consider the economic capacity of the specific permittee may not preclude imposition of BPJ limits that are beyond the economic capacity of the permittee. The Clean Water Act requires consideration of both costs and effluent reduction benefits.[284] This does not involve a formal balancing of

279. Memorandum from G. William Frick, Office of General Counsel, Clarification of O.G.C. Opinion No. 40 (Feb. 4, 1977) (quoting Opinion No. 40), *available at* http://www.epa.gov/npdes/pubs/owm504.pdf.

280. *Id.* The clarification also stated that State permit writers have the same discretion to consider costs as EPA.

281. A relevant issue is the "unit" at which economic achievability will be assessed. EPA's 2012 analysis of the economic achievability of CBM limits focuses on a CBM "project." EPA states that a project includes a "well, group of wells, lease, group of leases, or some other recognized unit that is operated as an economic unit when making production decisions. A project can be as small as a single well or a lease with just a few wells, or as large as over 1000 wells on multiple leases." EPA ECONOMIC ANALYSIS OF CBM INDUSTRY, *supra* note 50, at 2. The 1982 EPA guidance suggests that economic achievability be evaluated at the "firm" level rather than facility specific level.

282. *See* E.I. DuPont de Nemours v. Train, 430 U.S. 112, 129–30 (1977).

283. *See, e.g.*, Chemical Mfrs. Ass'n v. EPA, 870 F.2d 177 (5th Cir. 1989) (upholding pretreatment standards that EPA projected would result in closure of 14% of indirect discharging plants); Nat'l Ass'n of Metal Finishers v. EPA, 719 F.2d 624, 660 (3d Cir. 1983) *rev'd sub nom.* Chem. Mfrs. Ass'n v. Natural Res. Def. Council, 470 U.S. 116 (1985) (20% closure rate for electroplating industry).

284. BPT limits must be based on a comparison of "costs and effluent reduction benefits." Clean Water Act § 304(b)(1)(B), 33 U.S.C. § 1314(b)(1)(B) (2012). BAT factors include consideration of "costs," *id.* § 304(b)(2)(B), but the Fifth Circuit has said that BPJ limits for BAT should represent "a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges." Natural Res. Def. Council, Inc. v. EPA, 863 F.2d 1420, 1462 (9th Cir. 1988). In *American Petroleum Inst. v. EPA*, 787 F.2d 965,

these factors but a reasoned consideration and exercise of discretion,[285] and a permit writer may be justified in imposing a BPJ limit that is not achievable by a specific permittee based on a judgment that the costs are justified based on the quantity of pollutants removed by the limit.

Nonetheless, the relevant focus for CBM BPJ permits would seem to be whether the effluent limit prevents the permittee from operating at all. This is consistent both with EPA's limited guidance[286] and one Clean Water Act provision that provides for considering site-specific costs: under section 301(c) a discharger may obtain a variance from national BAT limits based on its economic inability to meet the limitation.[287]

But this begs the bigger question: what costs, short of preventing operation, are acceptable? Inevitably, increased costs of any BPJ limit will shorten the period in which gas extraction remains profitable, and EPA has justified not establishing a national effluent limitation guideline for CBM, in part, based on the costs associated with lost production.[288] EPA has, however, provided little guidance on the extent to which such costs are acceptable other than its statement that the issue is not a matter of law, but of "discretion."[289]

2. BPJ for CWTs

In those cases where in which EPA has established national effluent limitations guidelines, BPJ limits can also be established for specific pollutants that have not been limited in regulation.[290] In

972 (5th Cir. 1986), an earlier Fifth Circuit panel apparently recognized a role for assessing the relationship between costs and environmental benefits in setting BPJ limits. The court stated that BPJ limits might be arbitrary if their cost produced a de minimis reduction in pollutants. The court upheld a BPJ limit in the face of limited information of environmental benefits based on the fact that the cost would not be "significant."

285. *See id.*

286. *See supra* notes 260–61 and accompanying text.

287. Clean Water Act § 301(c), 33 U.S.C. § 1311(c) (2012). Any reduced effluent limitation established under § 301(c) must be set at the level that "will represent the maximum use of technology within the economic capability of the owner or operator." *Id.* Section 301(c) can, however, also be read to suggest that that facility-specific economic capacity cannot be considered in setting BPJ limits. The variance is only available for BAT on non-toxic, non-conventional limitations, and Congress did not authorize a site-specific economic variance from BPT, BCT or NSPS limits or BAT limits on toxic pollutants. *See* EPA v. National Crushed Stone Ass'n, 449 U.S. 64, 71--72 (1980).

288. *See supra* note 230 and accompanying text.

289. *See supra* notes 268–70 and accompanying text.

290. 40 C.F.R. § 125.3(c)(3) (2014).

Texas Oil and Gas Ass'n v. EPA,[291] the Fifth Circuit, for example, upheld EPA's application of permit-specific BPJ effluent limitations on pollutants not regulated under the Part 435 national effluent limitations for the Offshore Oil and Gas Subcategory. This certainly supports the position that permit writers have the authority to include technology-based limitations on pollutants not addressed in the Part 437 CWT category.

Although EPA has stated that BPJ limits generally may be set for "pollutants of concern," permit writers' authority to establish BPJ limits on pollutants not addressed in national effluent limitation guidelines is constrained. BPJ limits on such unregulated pollutants can be set only if those pollutants were not "considered by EPA" in developing the national guidelines.[292] This means that permit writers may need to review the administrative record of the promulgated effluent limitations guideline to determine which, if any, pollutants were considered, but not subsequently limited, in the establishing the national limitation.

EPA has specifically discussed the issue of permissible BPJ limits in CWT permits. In 2011 guidance, EPA stated that NPDES permits for CWT facilities receiving fracking wastewater may require "additional limits" for "pollutants in the wastewater that were not addressed in developing the CWT effluent guideline[s]."[293] The guidance specifically addresses only two pollutants. According to EPA, "radionuclides" were not "evaluated" in establishing the CWT guideline and therefore limits on radionuclides may be limited through the BPJ process. The guidance also specifically addresses "total dissolved solids" ("TDS").[294] Although the discharge of TDS in fracking wastewater is a significant concern,[295] the guidance states that EPA, "considered, but did not establish" limits on TDS in the national CWT guidelines.[296] Thus, EPA asserts that permit writers are precluded from establishing BPJ limits on TDS even if it is a "pollutant of concern." Other than radionuclides and TDS, the guidance does not address what other pollutants may have been "considered" in establishing CWT effluent limitations.

291. Texas Oil and Gas Ass'n v. EPA, 161 F.3d 923, 928--29 (5th Cir. 1998).
292. PERMIT WRITER'S MANUAL, *supra* note 153, at 5-46.
293. Hanlon Memo, *supra* note 93, at 11.
294. *Id.* at 12.
295. *See supra* notes 5–7 and accompanying text.
296. Hanlon Memo, *supra* note 93, at 12.

EPA's analysis of which pollutants can be limited through the BPJ process is troubling for several reasons. First, EPA's claim that TDS was considered in establishing the CWT guidelines is misleading. EPA, in the Federal Register, has published two proposals and two final actions establishing effluent limits for the CWT Point Source Category.[297] The only reference to TDS is found in the 1999 "supplemental proposal" of the CWT limitations. This proposal contains a discussion of whether high levels of TDS might interfere with the ability of facilities in the "Metals Subcategory" to meet proposed limits on metals.[298] Based on a review of a variety of data, EPA concluded that high levels of TDS in the subcategory would not prevent attainment of limits on metals.[299]

But EPA has stated that, at least for wastewater from the Marcellus Shale, the applicable CWT Subcategory is the "Organics Subcategory."[300] Nothing in the preambles to the proposals or final CWT regulations suggests that EPA considered establishing TDS limits for the Organics Subcategory. Moreover, even EPA's discussion of TDS in the context of the Metals Subcategory does not suggest that EPA "considered and rejected" a limit on TDS. Rather, discussion indicates only that EPA determined that a TDS limit was not necessary in order to achieve proposed limits on metals.[301] EPA never considered the need for TDS limits for their own sake. Nor does there appear to be any reasoned discussion on the achievability of a limit on TDS. Additionally, the 2000 Development Document for the CWT Category states that TDS was not selected for regulation because it is a "non-conventional bulk parameter" and EPA determined that "it is more appropriate to target specific compounds of interest rather than a parameter which measures a variety of pollutants in an industry."[302] This does

297. *See* 60 Fed. Reg. 5464 (proposed Jan. 27, 1995) (to be codified at 40 C.F.R. pt. 437) (initial proposal); 64 Fed. Reg. 2280 (proposed Jan. 13, 1999) (to be codified at 40 C.F.R. pt. 437) (1999) (supplemental proposal); 65 Fed. Reg. 81,242 (Dec. 22, 2000) (to be codified at 40 C.F.R. pts. 136 & 437) (final regulation): 68 Fed. Reg. 71,014 (Dec. 22, 2003) (to be codified at 40 C.F.R. pt. 437) (amendment to final regulation).

298. 64 Fed. Reg. at 2300.

299. *Id.*

300. *See supra* notes 244–48 and accompanying text.

301. *Id.*

302. ENVTL. PROT. AGENCY, EPA-821-R-00-020, DEVELOPMENT DOCUMENT FOR EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR THE CENTRALIZED WASTE TREATMENT INDUSTRY – FINAL, 7-1 (2000), *available at* http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20002NW7.txt.

not suggest that EPA "considered and rejected" a technology-based permit limit on TDS where warranted from a specific discharge.

This raises the second reason why EPA's analysis is troubling. For pollutants other than radionuclides and TDS, permit writers have little guidance on what pollutants have been "considered" in the CWT Category. The 2000 Development Document for the CWT Points Source Category discusses pollutants that were considered and the pollutants that were selected for regulation.[303] The document lists hundreds of pollutants that were "considered," and the list includes virtually all pollutants in CWT wastewater. This at least raises an argument that none of these pollutants can be subject to a BPJ limitation. Thus, EPA's position leaves the scope of BPJ limits on CWTs, and in fact any subcategory for which national limitations have been promulgated, uncertain.

V. Regulation of the Discharge of Fracking Wastewaters to Publicly Owned Treatment Works under the Clean Water Act

Under EPA regulations, all types of fracking wastewaters may be sent for treatment and disposal at a municipal sewage treatment facility, known as a "publicly owned treatment works" or "POTW." Although the POTW itself must obtain an NPDES permit, fracking facilities sending their wastes to a POTW for treatment are considered to be "indirect dischargers" under the Clean Water Act, and they are neither subject to the requirement to obtain an NPDES permit nor to the effluent limitations applicable to direct dischargers.[304] These indirect dischargers are regulated under the "pretreatment" requirements of the Clean Water Act.

A. Pretreatment Requirements for "Indirect Dischargers" under the Clean Water Act

Indirect dischargers, facilities that send their wastes to a POTW, are subject to their own special set of discharge limitations. Section 307(b) of the CWA requires EPA to develop "pretreatment standards" to prevent the introduction of pollutants that are not "susceptible to treatment" or which would "interfere with" the operation of a POTW.[305] EPA has implemented this requirement

303. *See id*. Ch. 6 & 7.
304. *See generally* GABA & STEVER, *supra* note 103, §§ 5:4–5:11.
305. Clean Water Act § 307(b), 33 U.S.C. § 1317(b) (2012).

by establishing two distinct classes of federal prohibitions on the introduction of wastes to POTWs: categorical technology-based pretreatment standards and a general prohibition.[306]

EPA can develop national, technology-based pretreatment standards that are "analogous" to technology-based limits applicable to direct dischargers.[307] A threshold requirement for developing categorical pretreatment standards is a determination that pollutants from an industrial subcategory would "pass through" or "interfere with" operations of a POTW.[308] To make this determination, EPA compares the level of treatment that would be provided by an average POTW with the level of treatment required by BAT/NSPS for that subcategory. If the percentage removal of the industry's pollutants achieved by an average POTW is less than the percentage removal required of direct dischargers, EPA concludes that the pollutants will pass through and that categorical "pretreatment standards" should be established.[309] In effect, an industry's pollutants will be found to "pass through," and pretreatment standards required, if greater amounts of those pollutants would be discharged if the industry sent its wastes to an average POTW compared to the amounts if the industry directly

306. Limitations on indirect dischargers can also be established by the state, municipal or local government entities or utilities. See 40 C.F.R. § 403.4 (2014). In some cases, EPA requires that POTWs develop "local limits" applicable to indirect dischargers. *Id.* § 403.5(c).

307. EPA has stated that:

> Categorical pretreatment standards are technology- based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT.

Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 78 Fed. Reg., 34,432, 34,438 (2013).

308. *See* 46 Fed. Reg. 9404, 9416 (1981).

309. EPA has described this process as follows:

> In determining whether a pollutant would pass through POTWs, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by BAT/NSPS treatment systems. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by direct dischargers complying with BAT/NSPS effluent limitations and standards. Pretreatment standards are established for those pollutants regulated under BAT/NSPS that pass through POTWs to waters of the U.S. or interfere with POTW operations or sludge disposal practices.

78 Fed. Reg. 34,432, 34,457 (2013). *See* Chemical Mfrs. Ass'n v. EPA, 870 F.2d 177, 243–249 (5th Cir. 1989).

discharged its wastes. Development of the pretreatment standards themselves is based on evaluation of the same economic and technological factors that apply in developing technology-based limits for direct dischargers, and the pretreatment standards are typically based on the same technology that formed the basis for the limits on direct dischargers.[310]

Additionally, EPA has promulgated a "general prohibition" that prohibits the introduction of wastes that will cause a POTW to violate the requirements of the POTW's NDPES permit.[311] This "general prohibition" applies whether or not categorical pretreatment standards have been promulgated. The key to understanding the "general prohibition" is to recognize that the level of treatment required of direct dischargers depends on the permit limitation established for the POTW: if the POTW is only required to meet minimum technology-based limits, then the general prohibition imposes limited constraints on the use of POTWs by indirect dischargers. More stringent limitations in a POTW permit can operate to indirectly impose more stringent limits on indirect dischargers.[312] Development of stringent, site-specific effluent limitations based on water quality standards is a difficult process,[313] and, even if included, enforcement of the general prohibition against indirect dischargers can raise difficult issues of proof.[314]

B. Pretreatment Requirements for Fracking Facilities

To date, EPA has not established national categorical limits on indirect discharges from any onshore fracking activities. The "Onshore Subcategory," applicable to shale gas production contains no pretreatment standards, and EPA has not developed any categorical standards, including pretreatment standards, for

310. EPA has stated that, "in selecting the PSES [Pretreatment Standards Existing Sources] technology basis, the Agency generally considers the same factors as it considers when setting BAT, including economic achievability. Typically, the result is that the PSES technology basis is the same as the BAT technology basis." 78 Fed. Reg. at 34,477.

311. 40 C.F.R. § 403.5. The regulation prohibits the introduction of pollutants that will "interfere with" or "pass through" the POTW. These terms are defined to include violation of the POTWs NPDES permit. *Id.* § 403.3(k),(p). POTW permits can contain limits not only on the discharge of POTW wastewater to surface water but also limitations on the concentrations of pollutants in the sewage sludge generated by the POTW treatment process. § 405(f), 33 U.S.C. § 1345(f).

312. *See* GABA & STEVER, *supra* note 103, § 5:09.

313. *See supra* notes 249 –61 and accompanying text.

314. *See, e.g.,* Arkansas Poultry Fed'n v. EPA, 852 F.2d 324 (8th Cir. 1988).

sources introducing wastewater from CBM activities. Thus, the only nationally applicable limitation on the transfer of fracking wastes to a POTW is the "general prohibition" that prevents a facility from introducing pollutants that cause a POTW to violate its own NPDES permit.

In 2011, as part of its Effluent Limitation Development Plan, EPA published its intent to develop categorical pretreatment standards for shale and CBM production.[315] Although EPA in 2013 apparently proposed to discontinue development of pretreatment standards for CBM production,[316] EPA is continuing to develop categorical pretreatment standards for shale gas production.[317] EPA has stated that it is engaged in studies of shale gas wastewater and treatment options as part of its plan to develop pretreatment standards. EPA has, however, suggested that it might not develop pretreatment standards for shale gas facilities if it finds that POTWs are "adequately treating shale gas wastewater so that it is not causing pass through or interference."[318]

EPA's statement that it may decline to develop pretreatment standards for shale gas facilities is itself remarkable. As discussed above, EPA states that a pollutant "passes through" a POTW where the percentage removal achieved by an average POTW is less than a direct discharger subject to technology-based effluent limitations.[319] Since the applicable technology-based limit for shale gas wastewater is "zero discharge," the discharge of any pollutants in shale gas wastewater from a POTW would constitute "pass through."[320] In other subcategories with a "zero discharge" requirement, EPA has acknowledged the need to develop pretreatment standards without even performing an initial pass through evaluation.[321] In other

315. 76 Fed. Reg. 66,286 (Oct. 26 2011).

316. 78 Fed. Reg. 48,193 (Aug. 7, 2013). *See supra* note 226 and accompanying text.

317. EPA previously stated its intention to develop pretreatment standards for both shale and CBM activities, *see* 76 Fed. Reg. at 66,295, and nothing in the 2013 statement proposes any different action.

318. 76 Fed. Reg. at 66,298.

319. *See supra* notes 307–310 and accompanying text.

320. *See* Hanlon Memo, *supra* note 93, at 10 ("TDS is not significantly removed by most conventional POTW treatment systems; therefore, pretreatment of the wastewater would be required prior to discharge to the POTW."). In the Coastal Subcategory of the Oil and Gas Point Source Category, EPA stated "due to the high solids content of drilling fluids and drill cuttings, EPA is establishing pretreatment standards for existing and new sources equal to zero discharge because these wastes would interfere with POTW operations." 61 Fed. Reg. 66,086, 66,102 (Dec. 16, 1996) (to be codified at 40 C.F.R. Part 435).

321. In proposed pretreatment standards for the Steam Electric Power Generating Point Source Category, for example, EPA stated:

words, despite EPA's odd suggestion, pollutants from shale gas wastewater almost certainly "pass though" a POTW. Based on a finding of "pass through," EPA must establish national pretreatment standards.

What might such pretreatment standards require? Pretreatment standards are technology-based limits, and they are generally based on the same technology available to direct dischargers.[322] In many, but not all cases, pretreatment standards are set at levels equivalent to comparable BPT/BAT/NSPS levels,[323] and a number of subcategories that have a direct discharge limit of zero discharge also have pretreatment standards of zero-discharge.[324] This is the case, for example, in the Coastal Subcategory of the Oil and Gas Point Source Category.[325] It remains to be seen, however, how EPA will evaluate the costs and availability of appropriate pretreatment technology for shale gas wastewater.

VI. Conclusion

Natural gas produced through hydraulic fracturing remains a critical, and controversial, component of U.S. production. A key

> EPA did not conduct its traditional pass-through analysis for these wastestreams [certain wastestreams with a proposed BAT limit of zero discharge] . . . because limitations for these wastestreams for direct dischargers would consist of no discharge of process wastewater pollutants to waters of the U.S., and therefore, all pollutants would "pass through" the POTW for these wastestreams.

78 Fed. Reg. 34,432, 34,457 (June 7, 2013).

322. *See supra* note 293 and accompanying text.

323. Even if "pass through" exists, EPA may not set pretreatment standards if the level of control by a well-operated POTW is equal or better than that achieved by the candidate pretreatment technology. *See, e.g.*, 47 Fed. Reg. 28260, 28262 (June 29, 1982) (to be codified at 40 CFR pt. 415) (declining to establish PSES for Inorganic Chemicals Manufacturing Point Source Category). Additionally, pretreatment standards are generally not established for "conventional pollutants" (BOD, TSS, pH, fecal coliform, and oil and grease) since those are generally well treated by POTW. *See* ENVTL. PROT. AGENCY, EPA-833-B-11-001, INTRODUCTION TO THE NATIONAL PRETREATMENT PROGRAM, 3-4 (2011), *available at* http://www.epa.gov/npdes/pubs/pretreatment_program_intro_2011.pdf.

324. *See, e.g.*, 40 C.F.R. §§ 412.25 (2014) (Ducks Subcategory NSPS of "no discharge"); 412.26 (Ducks Subcategory PSNS of "no discharge); *Id.* §§ 455.42 (BPT Pesticide Chemicals Formulating and Packaging Subcategory of "no discharge"), 455.46 (PSES Pesticide Chemicals Formulating and Packaging Subcategory of "no discharge"); *Id.* §§ 415.45 (Calcium Chloride Production Subcategory NSPS of "no discharge"), 415.46 (Calcium Chloride Production Subcategory PSNS of "no discharge").

325. *See* 40 C.F.R. §§ 435.43 (Coastal Subcategory BAT for produced water of "no discharge), 435.46 (Coastal Subcategory PSES for produced water of "no discharge.").

environmental issue associated with fracking is the management and disposal of the enormous quantities of wastewater generated in the process. At the moment, most of the focus on environmental regulation of fracking is on state and local actions.

Nonetheless, substantial federal authority exists to regulate fracking wastewater under the Resource Conservation and Recovery Act and the Clean Water Act. Regulation under RCRA, however, depends on classification of the wastewater as a "hazardous waste." Although EPA has generally exempted oil and gas wastes, including fracking wastewater, from classification as a RCRA hazardous waste, it appears that fracking wastewater generally would not be classified as a hazardous waste even without the exclusion. Tailored regulation under RCRA could, however, be accomplished through EPA adopting a set of "contingent management" requirements, but this would first require EPA to list fracking wastewater as a hazardous waste.

The discharge of fracking wastewater is also subject to regulation under the Clean Water Act. Fracking wastewaters generated from production of shale gas (and presumably natural gas from tight sandstone) are currently subject to the "technology-based" zero discharge limitation applicable to the oil and gas Onshore Subcategory. Since 1982, EPA has claimed that no national effluent limitations apply to the discharge of wastewaters generated from production of coal bed methane. EPA's position, originally adopted through private correspondence, is factually and procedurally improper, and its proposed decision to drop development of such limitations is based on unexplained economic judgments. Until properly excluded, CBM wastewaters fall squarely under the "zero discharge" requirement. EPA has also established no specific limitations on any fracking wastewaters sent to Publicly Owned Treatment Works. EPA policies suggest it must adopt a federal "pretreatment standard" for these wastewaters and that this standard should prohibit the transfer of fracking wastewater to POTWs.

EPA has the authority, but perhaps not the will, to establish a set of consistent national regulations that will assure the proper management of fracking wastewater. EPA must address these issues to assure that continued reliance on fracking in the U.S. is based on environmentally sound practices.