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REGULATION OF HYDRAULIC FRACTURING UNDER THE SAFE DRINKING WATER ACT

Keith B. Hall*

For more than 20 years after the 1974 enactment of the Safe Drinking Water Act (“SDWA”), the U.S. Environmental Protection Agency interpreted the SDWA as not applying to hydraulic fracturing. The United States Eleventh Circuit ruled in 1997 that the SDWA applied to fracturing, but the EPA chose not to consent to that interpretation outside the Eleventh Circuit. Further, the EPA continued to take the position that its existing SDWA regulations did not apply to hydraulic fracturing, and it never promulgated new regulations to cover fracturing. In 2005, the Congress passed legislation that generally is read as applying the SDWA to hydraulic fracturing if diesel is used in the fracturing fluid, but as excluding application of the SDWA if diesel is not used. After that statutory change, the EPA still appeared to maintain its previous position that its existing regulations did not apply to fracturing. In 2010, however, the EPA changed course, explicitly taking the position that its existing regulations apply to hydraulic fracturing if diesel is used. Two industry groups have challenged the EPA’s position in court, asserting that the EPA substantially changed its interpretation of an existing regulation, thereby imposing new regulatory burdens, and that the EPA could not do that without following the procedures required under the Administrative Procedures Act (“APA”) for enacting a new regulation. The resolution of the litigation could have implications not only for the use of diesel in hydraulic fracturing, but also more generally for establishing what limits exist on an agency’s authority to change its interpretation of regulations without following APA procedures.

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I. INTRODUCTION

Hydraulic fracturing is a “well stimulation” technique that has been used in over a million wells since the process was commercially developed in the late 1940s.¹ In recent years, advances in hydraulic fracturing and horizontal drilling have made it economically feasible to produce oil or natural gas from shale formations that contain those fluids. This has led to greatly increased use of hydraulic fracturing as companies develop shale formations in several parts of the United States. With increased use, often in areas of the country that have not seen significant oil or gas activity in generations, hydraulic fracturing has come under increased scrutiny. Many people have expressed environmental concerns, including worries that hydraulic fracturing might pose a threat to underground sources of drinking water.

This article: (1) explains what hydraulic fracturing is, and discusses the controversies relating to it; (2) provides an overview of the history of the Safe Drinking Water Act (“SDWA”), with particular reference to the SDWA’s history relative to hydraulic fracturing; (3) describes the current reach of the SDWA relative to fracturing; and (4) analyzes the current status of regulation, including a dispute regarding whether the EPA’s current SDWA regulations can be applied to fracturing without the EPA going through a notice and comment period pursuant to the Administrative Procedures Act.

II. HYDRAULIC FRACTURING AND HORIZONTAL DRILLING

A. The Basics of Hydraulic Fracturing

When oil or gas is discovered, it is not found in underground caverns. Instead, it is found in the pore spaces of underground rock formations.² After a successful well is drilled, oil or gas from the

¹ Thomas E. Kurth et al., *American Law and Jurisprudence on Fracing*, 47 ROCKY MTN. MIN. L. FOUND. J. 277 (2010).

² RICHARD C. SELLEY, *ELEMENTS OF PETROLEUM GEOLOGY* 239 (2d ed. 1998); JAMES G. SPEIGHT, *THE CHEMISTRY AND TECHNOLOGY OF PETROLEUM* 103 (2d ed. 1991). Indeed, the word “petroleum” is Latin for “rock oil.” See MERRIAM-WEBSTER’S NINTH NEW COLLEGIATE DICTIONARY 822, 879, 880 (1987) (822 (“oleum”), 879

surrounding formation travels through the rock itself to reach the well bore, and then up the well bore to the earth's surface.³ The oil or gas is able to travel through the rock by moving from one pore space to the next, through interconnections between the pores.⁴

Sometimes, a formation will contain oil or gas, but the interconnections between pore spaces will be too small in size or too few in number for oil or gas to flow very easily through the rock.⁵ Those "tight" formations⁶ have low permeability – a measure of how easily a fluid flows through a solid rock.⁷ If a formation's permeability is too low, oil or gas generally will not flow through the formation quickly enough to justify the substantial costs involved in drilling a well. In such cases, it will not be economically feasible to produce oil or gas from the formation using conventional techniques, even if the formation contains significant quantities of oil or gas.⁸

("petr"), 880 ("petroleum")); *cf.* DONALD J. BORROW, *DICTIONARY OF WORD ROOTS AND COMBINING FORMS* 66, 73 (1960) (describing both Latin and Greek origins).

³ SPEIGHT, *supra* note 2, at 142; MARTIN S. RAYMOND & WILLIAM L. LEFFLER, *OIL AND GAS PRODUCTION IN NONTECHNICAL LANGUAGE* 167 (2006).

⁴ RAYMOND & LEFFLER, *supra* note 3, at 39.

⁵ An analogy can be made between the rock formation and a house. From the street, a house may appear solid, but a person can enter the front door and walk from one room (pore) to the next room (pore), passing through doors and hallways (interconnections between pores) until he or she exits the back door, thereby having walked through the house.

⁶ The interconnections between pores sometimes are called "pore throats." *See* NORMAN J. HYNE, *NONTECHNICAL GUIDE TO PETROLEUM GEOLOGY, EXPLORATION, DRILLING AND PRODUCTION* 158 (2d ed. 2001)

⁷ *See* HOWARD R. WILLIAMS & CHARLES J. MEYERS, *MANUAL OF OIL & GAS TERMS* 998 (14th ed. 2009) [hereinafter *MANUAL OF OIL & GAS TERMS*] (revisions by Patrick Martin & Bruce Kramer) (also published in print as vol. 8. of WILLIAM & MYERS *OIL AND GAS LAW*) (defining "tight sands"); *see also* NAT'L ENERGY TECH. LAB., U.S. DEP'T OF ENERGY, *MODERN SHALE GAS IN THE UNITED STATES: A PRIMER* 15 (April 2009) [hereinafter *SHALE GAS PRIMER*] (referring to "tight gas").

⁸ *See* *MANUAL OF OIL & GAS TERMS* *supra* note 6, at 700 (defining "permeability of rock" as "A measure of the resistance offered by rock to the movement of fluids through it."); *see also* *SHALE GAS PRIMER*, *supra* note 6, at 82 (defining "permeability").

⁹ *See* DANIEL YERGIN, *THE QUEST: ENERGY, SECURITY, AND REMAKING THE MODERN WORLD* 326 (2011).

But production from low-permeability formations can become economical if the well operator can create cracks or fractures in the rock formation, so that the oil or gas can flow through the cracks, in addition to flowing through interconnections between pores.⁹ The process of creating such fractures is called “fracturing” (also sometimes called “fracking” or “fracing”).¹⁰ Starting in the late 1800s, companies sometimes engaged in fracturing by lowering an explosive charge into the well and detonating it. This was called “explosive fracturing.”¹¹

Hydraulic fracturing, sometimes called “hydrofracking” or “hydrofracturing,”¹² was commercially developed in about 1948, and since then, it has been used in over one million wells.¹³ In hydraulic fracturing, a fluid – typically a mixture of water and various additives – is pumped down the well and into a rock formation at high pressure.¹⁴ The high-pressure fluid causes the rock to fracture or crack, thereby creating additional pathways through which oil or gas can flow. When the high-pressure fracking fluid creating the cracks is removed, the fractures would close.¹⁵ To prevent this, small particles called proppants are mixed with the fracking water. The proppants are carried along with the water into the newly created fractures. When the high-pressure water is withdrawn, the proppants stay behind, propping open the fractures.¹⁶ Sand is the most common proppant, but sometimes resin-coated sand or small, specially manufactured ceramic or bauxite particles are used.¹⁷

⁹ See *id.* at 327, 329.

¹⁰ Thomas E. Kurth et al., *American Law and Jurisprudence on Fracing*, 47 ROCKY MTN. MIN. L. FOUND. J. 277 (2010); see also MANUAL OF OIL & GAS TERMS, *supra* note 6, at 377 (“frac”).

¹¹ See NORMAN J. HYNE, Nontechnical Guide to Petroleum Geology, Exploration, Drilling and Production 422 (2d ed. 2001); see also *Roberts v. Dickey*, 20 F. Cas. 880, 883-84 (W.D. Pa. 1871) (discussing patent granted in 1866 for invention relating to explosive fracturing).

¹² MANUAL OF OIL & GAS TERMS, *supra* note 6, at 450.

¹³ Kurth et al., *supra* note 11, at 279.

¹⁴ SHALE GAS PRIMER, *supra* note 6, at 82 (defining “hydraulic fracturing”); see also MANUAL OF OIL & GAS TERMS, *supra* note 6, at 450.

¹⁵ Kurth et al., *supra* note 10.

¹⁶ SPEIGHT, *supra* note 2, at 141.

¹⁷ See Robin Beckwith, *Proppants: Where in the World*, J. PETROLEUM TECH. ON-

Typically, about 99.5% of the fracturing fluid will consist of water and proppants,¹⁸ but operators also add various other substances to hydraulic fracturing water, including biocides to control the growth of microorganisms, corrosion inhibitors to protect the well's piping, chemicals to decrease friction between fracking water and the well's piping, and viscosity adjusters to help the fracking water carry proppants into fractures.¹⁹

In a small fraction of fracturing operations, diesel fuel is included in the fracturing fluid. Companies that perform hydraulic fracturing historically have treated the identity of the specific chemicals they use as proprietary information.²⁰

During the fracking job, high-pressure pumps are used to supply the hydraulic pressure needed to cause fracturing. Once the fracking job is complete, the pumps are turned off, and thus no longer apply the high pressure. The company performing the frack job then allows the target formation's own pressure to push the fracking fluid back through the well bore and to the surface, where the fluid, called "flow back," is recovered. Typically, thirty to seventy percent of the fluid initially used in the fracking process is recovered as flow back.²¹

LINE, Apr. 2011, at 36-40 available at <http://www.spe.org/jpt/print/archives/2011/04/11ProppantShortage.pdf>.

¹⁸ SHALE GAS PRIMER, *supra* note 6, at 62.

¹⁹ *Id.* at 61-4.

²⁰ See Keith B. Hall, *Hydraulic Fracturing: Mandatory Disclosure of Fracking Water Additives*, OIL & GAS LAW BRIEF (Mar. 14, 2011), <http://www.oilgaslawbrief.com/hydraulic-fracturing/mandatory-disclosure-of-fracking-water-additives/>. For an interesting article advocating that trade secret protections be removed, and that an intellectual property right in the composition of fracking additives be granted, see Hannah Wiseman, *Trade Secrets, Disclosure, and Dissent in a Fracturing Revolution*, 111 COLUM. L. REV. SIDEBAR 1 (2011), available at http://columbialawreview.org/assets/sidebar/volume/111/1_Wiseman.pdf. For a view that trade secret protections should be maintained, see Keith B. Hall, *Hydraulic Fracturing: Fracking Additives and Trade Secrets*, OIL AND GAS LAW BRIEF (Mar. 21, 2011), <http://www.oilgaslawbrief.com/hydraulic-fracturing/fracking-additives-and-trade-secrets/>.

²¹ See SHALE GAS PRIMER, *supra* note 6, at 66.

III. HORIZONTAL DRILLING

Traditionally, oil and gas wells have been “vertical wells,” and vertical wells still are the most common type of well.²² Vertical wells are drilled more or less straight downward, which results in the bottom of the well being almost directly below the well pad from which the drilling is performed.²³ But by the 1930s, operators had developed “directional drilling,” in which drilling may start vertically downward, before deviating to a diagonal direction.²⁴ This is useful for situations in which the surface location that is directly above the desired location for the bottom of the well below a surface location where it would be difficult to drill.²⁵ Operators also developed “horizontal drilling,” in which they begin drilling vertically downward, but then gradually turn the direction of drilling (at the “kickoff point”)²⁶ until the drilling is proceeding in a horizontal direction.²⁷

Horizontal drilling can have certain advantages, including the possibility of having a longer distance of the well bore exposed to the formation from which oil or gas will be produced.²⁸ This is an advantage because whenever an oil or gas well is completed, oil or gas does not enter an opening at the very bottom of the well pipe. Instead, after drilling is completed, a special tool is used to create perforations in the sides of the well pipe.²⁹ The oil or gas enters the well bore through those perforations.³⁰ If the rock formation from which oil or gas is to be produced is anywhere from 50 to 200 feet

²² See YERGIN, *supra* note 8, at 17; cf. HYNE, *supra* note 5, at 285–6.

²³ Often, however, there is some deviation from straight vertical, even if the operator is not intending to deviate. See HYNE, *supra* note 5, at 285–6.

²⁴ See HYNE, *supra* note 5, at 285–9; cf. Lamont C. Larsen, *Horizontal Drafting: Why Your Form JOA Might Not Be Adequate for Your Company’s Horizontal Drilling Program*, 48 ROCKY MTN. L. FOUND. J. 51, 51 (2011).

²⁵ See HYNE, *supra* note 5, at 289–90.

²⁶ See *id.* at 286 (turning the direction of drilling from vertical to an angle is “kicking off the well”).

²⁷ See YERGIN, *supra* note 8, at 17.

²⁸ See *id.* at 328; LARSEN, *supra* note 24, at 53.

²⁹ See HYNE, *supra* note 5, at 344–45.

³⁰ See HYNE, *supra* note 5, at xl.

thick in a vertical direction, then the maximum length of well pipe that could be perforated would be between 50 and 200 feet in a vertical well.³¹

But a formation that is only 50 to 200 feet thick in a vertical direction may extend for many miles in each horizontal direction.³² Thus, if a well is drilled horizontally through the middle of the rock formation from which oil or gas is produced, a much greater length of pipe can be perforated.³³ Some wells in shale formations are drilled with horizontal legs as long as a mile in length, with a significant portion of that length being perforated.³⁴ This results in a much greater number of perforations into which oil or gas can flow, and therefore a much higher rate of production.³⁵

IV. BENEFITS OF HYDRAULIC FRACTURING AND HORIZONTAL DRILLING

Hydraulic fracturing has been used for decades in producing oil or natural gas from other low-permeability formations, such as “tight sands.”³⁶ Fracturing also has been used to facilitate the production of natural gas from coal seams.³⁷

In recent years, hydraulic fracturing has been used with increasing frequency to produce oil and gas from shale formations in several parts of the country. Shale has a very low permeability, and in the past, it was not economically feasible to produce oil or gas from shale.³⁸ Improvements in hydraulic fracturing and horizontal drilling have changed that.³⁹ Active shale plays now include the Haynesville Shale in northwest Louisiana, currently producing more natural gas than any other shale play,⁴⁰ the Barnett Shale near

³¹ *See id.* at 127.

³² *Cf. LARSEN, supra* note 25, at 53.

³³ *See id.*

³⁴ *See id.* at 53.

³⁵ *See id.*

³⁶ *See SHALE GAS PRIMER, supra* note 6, at 15.

³⁷ *See id.*

³⁸ *See YERGIN, supra* note 8, at 326.

³⁹ *See id.* at 329.

⁴⁰ State of Louisiana Dep’t of Natural Resources, *Haynesville Shale Passes Bar-*

Forth Worth, the Antrim Shale in Michigan, the Fayetteville Shale in Arkansas, the Woodford Shale in Oklahoma, and the Marcellus Shale in the Northeast.⁴¹

Fracking has some great benefits. It creates jobs and tax revenues.⁴² It promotes national security by decreasing the United States' reliance on foreign sources of energy.⁴³ Fracking even has potential environmental benefits because often it is used to produce natural gas, the cleanest burning of all fossil fuels.⁴⁴ For a given amount of heat output, the combustion of natural gas results in only half as much carbon dioxide as does the burning of coal, and about thirty percent less carbon dioxide than the burning of oil.⁴⁵ This has prompted some people to advocate increased use of natural gas as a "bridge fuel" that could be a cleaner alternative to other fossil fuels until some hoped-for day when most of the nation's energy needs could be met through renewable energy sources.⁴⁶ The combustion of natural gas also produces less particulate matter, less sulfur dioxide, and less nitrous oxides than the burning of coal or oil.⁴⁷

nett Shale Natural Gas Production, TOP STORIES (Mar. 18, 2011), <http://dnr.louisiana.gov/index.cfm?md=newsroom&tmp=detail&aid=847>.

⁴¹ See SHALE GAS PRIMER, *supra* note 7 (discusses each of these shale plays). In addition, the Energy Information Administration's website has a map of shale plays, though the map does not distinguish between shale formations that are being actively developed and those that have seen little or no activity. U.S. Energy Info. Admin., *Analysis and Projections: Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*, ANALYSIS & PROJECTIONS (July 8, 2011), <http://www.eia.gov/analysis/studies/usshalegas/>.

⁴² LOREN C. SCOTT, ECONOMIC IMPACT OF THE HAYNESVILLE SHALE ON THE LOUISIANA ECONOMY (Apr. 2010), available at <http://www.loga.la/pdf/Economic%20Impact%20of%20HS.pdf>; *Oil Drilling Creating Dozens of Jobs in SE Wyo.*, WYOMING TRIBUNE EAGLE (Mar. 11, 201), <http://www.kulr8.com/news/wyoming/117740238.html>.

⁴³ SHALE GAS PRIMER, *supra* note 6, at 4.

⁴⁴ *Id.* at 5.

⁴⁵ *Id.*

⁴⁶ JOHN D. PODESTA & TIMOHTY E. WIRTH, NATURAL GAS: A BRIDGE FUEL FOR THE 21ST CENTURY, (Aug. 10, 2009), available at <http://www.americanprogress.org/issues/2009/08/pdf/naturalgasmemo.pdf>.

⁴⁷ SHALE GAS PRIMER, *supra* note 6, at 5.

A. Environmental Concerns

People have also raised environmental concerns about fracking, with most of the concerns relating to water. There are three major issues relating to water: (1) where to get the water for fracking;⁴⁸ (2) whether the fracking process itself is a threat to underground sources of drinking water; and (3) how to dispose of flow back, the fracturing fluid that is recovered after fracking is complete.

V. THE SAFE DRINKING WATER ACT

A. Background

Congress enacted the Safe Drinking Water Act (“SDWA”) in 1974⁴⁹ in order “to assure that water supply systems serving the public meet minimum national standards for protection of public health.”⁵⁰ The SDWA addresses several issues, including the establishment of maximum contaminant levels,⁵¹ prohibitions on the use of lead pipes in drinking water systems,⁵² protection of underground sources of drinking water,⁵³ and water treatment.⁵⁴

Part C of the SDWA addresses the protection of underground sources of drinking water (“USDW”).⁵⁵ Part C requires the United States Environmental Protection Agency (“EPA”) to develop regulations for state underground injection control (“UIC”) programs, including “minimum requirements for effective programs to prevent underground injection which endangers drinking water sources.”⁵⁶

⁴⁸ *Id.* at 64–66.

⁴⁹ *W. Va. Univ. Hosps. v. Casey*, 499 U.S. 83, 89 n.4 (1991); *Miami-Dade Cnty. v. EPA*, 529 F.3d 1049, 1052 (11th Cir. 2008); *Legal Envtl. Assistance Found., Inc. v. EPA (LEAF I)*, 118 F.3d 1467, 1469 (11th Cir. 1997).

⁵⁰ H.R. Rep. No. 93-1185 (1974); *See also Miami-Dade*, 529 F.3d at 1052.

⁵¹ 42 U.S.C. § 300g-1 (2000).

⁵² *Id.* § 300g-6.

⁵³ *Id.* § 300h.

⁵⁴ *See id.* § 300j.

⁵⁵ *Id.* § 300h-h(8); *Miami-Dade*, 529 F.3d at 1052.

⁵⁶ 42 U.S.C. § 300h(a)-(b). Part C defines “underground injection” as being “the subsurface emplacement of fluids by well injection.”

The SDWA directs that the minimum requirements developed by the EPA must include the mandate that an effective State UIC program shall “prohibit . . . any underground injection in such State which is not authorized by permit . . . [or] rule,”⁵⁷ and that the state shall not authorize by permit or rule “any underground injection which endangers drinking water sources.”⁵⁸

B. Primacy

If the EPA determines that a particular state has developed a UIC program that meets the EPA’s minimum regulatory standards, that state may assume primary responsibility, or “primacy,” for regulating underground injections.⁵⁹ If a state fails to develop a satisfactory UIC program, the EPA is required to develop a UIC program for that state.⁶⁰ Similarly, if a state obtains primacy for SDWA UIC enforcement, but the EPA subsequently determines that its UIC program no longer meets minimum standards, the EPA must develop a UIC program for that state.⁶¹

The SDWA provides two procedures for a state to obtain primacy for its UIC regulations. First, 42 U.S.C. § 300h-1(b)(1)(A) (2010) provides that a state can obtain primacy by showing that its UIC regulations satisfy all the regulations promulgated by the EPA under 42 U.S.C. § 300h. Those EPA regulations are found in 40 C.F.R. § 145 (2011).

An alternative procedure is provided by 42 U.S.C. § 300h-4(a). That provision allows a state to gain primacy by demonstrating that its UIC regulations meet the requirements set forth in 42 U.S.C. § 300h(b)(1)(A), and that its regulatory program “represents an effective program to prevent underground injection which endangers drinking water sources.”⁶² The procedure authorized by 42 U.S.C. § 300h-4(a) is a more “flexible” process than that

⁵⁷ *Id.* § 300h(b)(1)(A).

⁵⁸ *Id.* § 300h(b)(1)(B).

⁵⁹ *Id.* § 300h-1(b)(3).

⁶⁰ *Id.* § 300h-1(c).

⁶¹ *Id.*

⁶² *Legal Envtl. Assistance Found., Inc. v. EPA (LEAF II)*, 276 F.3d 1253, 1257 (11th Cir. 2001).

authorized by 42 U.S.C. § 300h-1(b)(1)(A), but the more flexible process for obtaining primacy only applies to certain portions of UIC regulations. Specifically, this process applies to the “portion of any state underground injection control program which relates to (1) the underground injection of [produced water], or (2) any underground injection for the secondary or tertiary recovery of oil or natural gas.”⁶³

Thirty-three states have primacy, and an additional seven states share SDWA enforcement authority with the EPA.⁶⁴ The states having primacy include several in which hydraulic fracturing is being used to develop shale plays, or where such activity is anticipated, including Texas,⁶⁵ Louisiana,⁶⁶ Arkansas,⁶⁷ Oklahoma,⁶⁸ West Virginia,⁶⁹ North Dakota,⁷⁰ and Ohio.⁷¹ For ten states, the EPA administers the UIC program.⁷² These states also include several

⁶³ 42 U.S.C. § 300h-4(a) (2000).

⁶⁴ Information on each state may be found at 40 C.F.R. Part 147 (2011). *See also* EPA, *UIC Program Primacy*, WATER: UNDERGROUND INJECTION CONTROL, <http://water.epa.gov/type/groundwater/uic/Primacy.cfm#who> (last updated, Mar. 6, 2012) [hereinafter *EPA UIC Program Primacy*].

⁶⁵ 40 C.F.R. §§ 147.2200, 2201 (2011); SHALE GAS PRIMER, *supra* note 6, at 18, 20 (the Barnett Shale is in the area around Fort Worth, the Eagle Ford Shale is in southern Texas, and a small portion of the Haynesville Shale extends into East Texas); *see also* U.S. Energy Info. Admin., *Lower 48 States Shale Plays*, ENERGY IN BRIEF: WHAT IS SHALE GAS AND WHY IS IT IMPORTANT? [hereinafter *EIA Lower 48*] (May 9, 2011), http://www.eia.gov/oil_gas/rpd/shale_gas.pdf (for location of Eagle Ford, as well as Haynesville shale formations).

⁶⁶ 40 C.F.R. § 147.950 (2011); *see also* SHALE GAS PRIMER, *supra* note 6, at 20 (the Haynesville Shale is located primarily in northwestern Louisiana).

⁶⁷ 40 C.F.R. § 147.20; *see* SHALE GAS PRIMER, *supra* note 6, at 19 (the Fayetteville Shale is in Arkansas).

⁶⁸ 40 C.F.R. § 147.1850, 1851; *see* SHALE GAS PRIMER, *supra* note 6, at 22 (the Woodford Shale is in Oklahoma).

⁶⁹ 48 Fed. Reg. 55127, 55127 (Dec. 9, 1983); *see* SHALE GAS PRIMER, *supra* note 6, at 13, 21 (the Marcellus Shale extends into West Virginia).

⁷⁰ 40 C.F.R. § 147.1750; *see also* *EIA Lower 48*, *supra* note 65.

⁷¹ 40 C.F.R. § 147.1800, 1801; *see also* SHALE GAS PRIMER, *supra* note 6, at 21 (the Marcellus Shale extends into Ohio).

⁷² The EPA administers the UIC programs for New York, Pennsylvania, Virginia, Kentucky, Tennessee, Michigan, Minnesota, Iowa, Arizona, and Hawaii. EPA *UIC Program Primacy*, *supra* note 64.

states with shale play activity, including Pennsylvania,⁷³ New York,⁷⁴ Michigan,⁷⁵ and Kentucky.⁷⁶ Seven states administer a portion of the UIC program, while the EPA administers the remainder. These states include Colorado, Indiana, and Montana, each of which has shale resources.

C. The Six Classes of Injection Wells

Title 40, Part 144 of the Code of Federal Regulations contains numerous substantive requirements for UIC programs, including the requirements for states to obtain primacy. For example, Part 144 now establishes six (originally there were five) classes of UIC wells, with particular regulatory requirements for each.⁷⁷

The first class, Class I wells, are wells used to inject wastes “beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water.”⁷⁸

Class II wells are wells in which fluids are injected for disposal of produced water and certain wastewater associated with oil and gas production, “enhanced recovery of oil or natural gas,” or for storage of liquid hydrocarbons.⁷⁹

Class III wells are wells associated with certain mining activity.⁸⁰

Class IV wells are wells used for injection of wastes into a formation that contains an underground source of drinking water

⁷³ 40 C.F.R. § 147.1951 (2011); *see also* SHALE GAS PRIMER, *supra* note 6, at 21 (the Marcellus Shale underlies much of Pennsylvania).

⁷⁴ 40 CFR § 147.1651; *see also* SHALE GAS PRIMER, *supra* note 6, at 21 (the Marcellus Shale extends into New York). New York had a moratorium on the hydraulic fracturing of horizontal wells. The moratorium was imposed by former Governor David Paterson. N.Y. EXEC. ORDER NO. 41 (2010), *available at* <http://www.governor.ny.gov/archive/paterson/executiveorders/EO41.html>.

⁷⁵ 40 C.F.R. § 147.1151 (2011). The Antrim Shale underlies much of Michigan’s southern peninsula. *See* SHALE GAS PRIMER, *supra* note 6, at 23.

⁷⁶ 40 C.F.R. § 147.901 (2011). The Marcellus Shale extends into Kentucky. *See* SHALE GAS PRIMER, *supra* note 6, at 21.

⁷⁷ 40 C.F.R. § 144.6 (2011).

⁷⁸ *Id.* § 144.6(a).

⁷⁹ *Id.* § 144.6(b).

⁸⁰ *Id.* § 144.6(c).

within one-quarter mile of the well.⁸¹

Class V wells are injection wells that do not fit into any other category of injection well.⁸²

Class VI wells – a relatively new class – are wells for the injection of carbon dioxide for carbon sequestration.⁸³

VI. HISTORY OF THE SDWA IN RELATION TO FRACKING

A. Pre-*LEAF*

Hydraulic fracturing had been used commercially for over twenty-five years by the time the SDWA was enacted in 1974.⁸⁴ But in 1974 and for years afterward, industry, the EPA, and state regulators all seemed to believe that fracturing was not subject to regulation under the SDWA.⁸⁵ This belief likely was influenced by the fact that: (1) the purpose of hydraulic fracturing is not disposal; (2) the fracturing process lasts for a relatively short time, after which a well may produce oil or gas for years; (3) much, though not all, of the fracturing fluid is recovered from the well; and (4) some of the SDWA's language, as well as some of its legislative history, suggest that the SDWA was intended, for the most part, not to regulate drilling for oil or gas.⁸⁶ Because neither industry nor the regulatory community believed the SDWA applied to hydraulic fracturing, decades passed without any active regulation of hydraulic fracturing under the SDWA. This was challenged in 1994.

⁸¹ *Id.* § 144.6(d).

⁸² *Id.* § 144.6(e).

⁸³ *Id.* § 144.6(f).

⁸⁴ Hydraulic fracturing was commercially developed in approximately 1948. *See* Kurth, *supra* note 11, at 279 n.4.

⁸⁵ 151 CONG. REC. S7267-01 at S7278 to S7279 (daily ed. June 23, 2005) (referring to EPA's understanding of SDWA) (environmental organization in 2005 referred to failure of all states, other than Alabama, to regulate hydraulic fracturing under SDWA); *see LEAF I*, 118 F.3d 1467 (Alabama took the position during this litigation in the 1990s that the SDWA did not apply to hydraulic fracturing).

⁸⁶ These facts were raised in the *LEAF* litigation. *See LEAF I*, 118 F.3d 1467.

B. The *LEAF* Litigation

Use of hydraulic fracturing is not limited to shale plays. In 1994, the Legal Environmental Assistance Foundation (“LEAF”) petitioned the EPA to initiate proceedings to withdraw its prior approval of Alabama’s underground injection control program.⁸⁷ LEAF asserted that Alabama’s UIC program was deficient because it did not regulate hydraulic fracturing of coal seams as an underground injection for purposes of the SDWA.⁸⁸ The EPA denied LEAF’s petition, concluding that Alabama’s UIC program was not deficient.⁸⁹ The EPA reasoned that the regulatory definition of “underground injection” only encompassed wells whose “principal function” is the underground injection of fluids, and this is not the principal purpose of the wells in which hydraulic fracturing is used.⁹⁰ Instead, the principal function of such wells is to produce natural gas.⁹¹

After LEAF’s petition was denied, it brought suit for review.⁹² LEAF contended that the EPA’s interpretation of its regulations would make the regulations inconsistent with the SDWA.⁹³ The EPA disagreed, arguing that the statutory definition of “underground injection” found in the SDWA was ambiguous, that Congress had only intended the SDWA to apply to wells whose principal purpose was underground injection, and that the EPA’s regulations were based on a permissible interpretation of the SDWA.⁹⁴ The EPA also argued that legislative history indicated that Congress did not want to regulate oil and gas drilling activities.

The Eleventh Circuit began by rejecting the EPA’s argument that the SDWA does not apply unless a well’s “principal function” is underground injection. The court noted that Part C requires states to “prohibit . . . *any* underground injection” that is not authorized

⁸⁷ *Id.* at 1471.

⁸⁸ *See id.*

⁸⁹ *See id.*

⁹⁰ *See id.*

⁹¹ *See id.*

⁹² *See id.* at 1472.

⁹³ *See id.*

⁹⁴ *See id.* at 1473–4.

by permit or rule.⁹⁵ Thus, the SDWA requires regulation of all wells used for “underground injection,” even if the wells might have an additional purpose—even a primary purpose—other than underground injection.⁹⁶ Therefore, it did not matter that gas production was the principal function of the wells that were being hydraulically fractured in Alabama. The court stated that “conceivably” the EPA could apply UIC regulations only during the period of time a well was being fractured, and not during gas production, but that EPA could not exempt the wells from UIC regulations altogether if hydraulic fracturing qualified as an “underground injection.”⁹⁷

Next, the court analyzed whether hydraulic fracturing fit within the statutory definition of “underground injection.” At that time, the SDWA defined “underground injection” as “the subsurface emplacement of fluids by well injection.”⁹⁸ The court concluded that hydraulic fracturing “obviously falls within this definition.”⁹⁹

In briefing, the EPA noted that the Alabama Department of Environmental Management (“DEM”) had argued that fracturing does not involve the underground “emplacement” of fluids because “emplacement” implies that a fluid is permanently placed in a location, but a substantial portion of fracking water is recovered as flow back water after the fracking is complete.¹⁰⁰ The Eleventh Circuit Court of Appeals rejected this argument too, noting that a portion of fracking fluid is not recovered.¹⁰¹ The court reasoned that the unrecovered fluid should be considered “emplaced” even if “emplace[ment]” was interpreted to mean permanently placed underground.¹⁰² Further, the court stated that the EPA’s regulations treated certain other activities as an underground injection, even

⁹⁵ *See id.* at 1474 (quoting 42 U.S.C. § 300h(b)(1)).

⁹⁶ *See id.* at 1475.

⁹⁷ *See id.* at 1475 n.11.

⁹⁸ *LEAF I*, at 1470 (quoting 42 U.S.C. § 300h(d)(1) (definition is the same as in 2010 edition)).

⁹⁹ *Id.* at 1474–5.

¹⁰⁰ Brief of Respondent at 24 n. 12, *LEAF I*, 118 F.3d 1467 (11th Cir. 1997) (No. 95-6501) 1995 WL 17057927, at *24 (The EPA did not expressly adopt this argument); *See LEAF I* at 1474 n.10.

¹⁰¹ *LEAF I* at 1475.

¹⁰² *Id.*

though those activities involve a temporary emplacement of fluids underground.¹⁰³

The court then examined the EPA's argument that the SDWA's legislative history demonstrated that the Congress did not intend for the SDWA to apply to "drilling techniques."¹⁰⁴ The court rejected that argument as well, concluding that hydraulic fracturing is not a drilling technique.¹⁰⁵ Instead, it is a post-drilling technique.¹⁰⁶ Finally, the court rejected the EPA's legislative history argument. The primary legislative history to which the EPA pointed was no more than a "brief exchange" during floor debate.¹⁰⁷ Moreover, because the SDWA's language was clear, there was no reason to resort to legislative history.¹⁰⁸ Accordingly, concluded the court, the EPA was required to treat hydraulic fracturing as an "underground injection" for purposes of the SDWA and the EPA's SDWA regulations.¹⁰⁹

After *LEAF*, the EPA did not amend its regulations to expressly require states to regulate hydraulic fracturing as an underground injection. Further, it did not begin requiring states outside the jurisdiction of the Eleventh Circuit Court of Appeals to regulate hydraulic fracturing under the SDWA.

C. *LEAF II*

After the 1997 *LEAF* decision, the Eleventh Circuit granted *LEAF*'s request for a writ of mandamus to enforce the decision.¹¹⁰ The EPA then began proceedings to withdraw its approval of Alabama's Class II UIC program.¹¹¹ Before those withdrawal proceedings were complete, Alabama submitted a proposal for a revised UIC program.¹¹²

¹⁰³ *Id.*

¹⁰⁴ *Id.* at 1475–1476.

¹⁰⁵ *See id.* at 1476–1477.

¹⁰⁶ *See id.*

¹⁰⁷ *Id.*

¹⁰⁸ *See id.* at 1475.

¹⁰⁹ *See id.* at 1476.

¹¹⁰ *See LEAF II*, 276 F.3d at 1256.

¹¹¹ *See id.*

¹¹² *See id.*; *see also* Notice of Proposal to Approve Alabama's Class II UIC Pro-

The SDWA provides two procedures for states to obtain primacy – that is, the EPA’s approval of the state’s UIC program.¹¹³ Alabama sought approval of its revised UIC program pursuant to § 1425 of the SDWA, and the EPA approved the program.¹¹⁴ LEAF objected.¹¹⁵ LEAF asserted that hydraulic fracturing was not one of the types of activities listed in § 1425 of the SDWA.¹¹⁶ Accordingly, Alabama should be required to demonstrate that its revised program could satisfy the showing required by SDWA § 1422(b).¹¹⁷ LEAF also argued that Alabama’s revised program should be rejected because hydraulically fractured wells are Class II wells, but Alabama’s proposed program would not regulate hydraulically-fractured wells as Class II wells.¹¹⁸

The Eleventh Circuit Court first examined LEAF’s argument that § 1425 of the SDWA (codified at 42 U.S.C. § 300h-4) does

gram Revision, 64 Fed. Reg. 56986 (Oct. 22, 1999) (to be codified at 40 C.F.R. pt. 147).

¹¹³One of the two procedures for a state to gain primacy is provided by § 1422(b) of the SDWA, which is codified at 42 U.S.C. § 300h-l(b) (2011). That procedure requires a state to show that its UIC program satisfies all the regulations promulgated pursuant to 42 U.S.C. § 300h.

The other procedure for seeking primacy, which is authorized by § 1425 of the SDWA (codified at 42 U.S.C. § 300h-4(a)), has been described as a “more flexible” procedure. *See LEAF II*, 276 F.3d at 1257. To obtain primacy under the second procedure, a state must show that its UIC program meets the requirements of § 1421(b)(1)(A)-(D) of the SDWA (codified at 42 U.S.C. § 300h(b)(1)(A)-(D)), and that the program is an “effective program to prevent underground injection which endangers drinking water sources.” *See LEAF II*, 276 F.3d at 1257; *see also* 42 U.S.C. § 300h-4. But the SDWA § 1425 procedure only applies to the portion of a State’s UIC program that “relates to” wells used for underground disposal of brine and produced water, or any “underground injection for the secondary or tertiary recovery of oil or natural gas.” *See LEAF II*, 276 F.3d at 1259; *see also* 42 U.S.C. § 300h-4(a).

¹¹⁴*See LEAF II*, 276 F.3d at 1256; *see also* State of Alabama Underground Injection Control (UIC) Program Revision: Approval of Alabama’s Class II UIC Program Revision, 65 Fed. Reg. 2889-97 (Jan. 19, 2000) (to be codified at 40 C.F.R. pt. 147).

¹¹⁵*See LEAF II*, 276 F.3d at 1256; 42 U.S.C. § 300h-4 (2011).

¹¹⁶*See id.* at 1256.

¹¹⁷*See id.* at 1256–7; 42 U.S.C. § 300h-l.

¹¹⁸*See id.* at 1256.

not apply to hydraulically-fractured wells.¹¹⁹ Section 25 states that it applies to any well that “relates” to the disposal of produced water or to injections associated with the secondary or tertiary recovery of oil or natural gas.¹²⁰ LEAF argued that SDWA § 1425 did not apply because hydraulic fracturing does not involve the disposal of produced water (brine), and it is not an injection for the secondary or tertiary recovery¹²¹ of oil or natural gas.¹²²

The EPA acknowledged that hydraulically-fractured wells are not wells for the disposal of produced water (brine), and that they are not wells for the secondary or tertiary recovery of oil or natural gas.¹²³ But the EPA argued that hydraulic fracturing and secondary and tertiary recovery are all processes for increasing the recovery of oil or natural gas.¹²⁴ Therefore, hydraulic fracturing is an “analogous” process that “relates” to secondary or tertiary recovery.¹²⁵ Further, the plain language of 42 U.S.C. § 300h-4 states that it applies to any well that “relates” to secondary or tertiary recovery.

The court examined the EPA’s position under the standard outlined in *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*¹²⁶ Under this standard, if “Congress has directly spoken to the precise question at issue,” and if “the intent of

¹¹⁹ *See id.* at 1256–57.

¹²⁰ *See* 42 U.S.C. § 300h-(4)(a); *see also* *LEAF II*, 276 F.3d. at 1256, 1257;

¹²¹ “Secondary recovery” is “a process of injecting as or water into a reservoir to restore production when the primary drive has been depleted.” *See* HYNNE, *supra* note 5, at 523. “Tertiary recovery” “is used after the primary drive mechanism has been depleted and secondary recovery has been completed on an oil reservoir. Either a) chemicals or steam is injected into a reservoir or b) the subsurface oil is set afire.” *Id.* at 537. The “primary drive” is “the original force which causes oil or gas to flow through the reservoir rock and into a well.” *Id.* at 54. A reservoir may initially be under sufficient pressure that the pressure serves as the primary drive that causes the oil or gas to flow. As the reservoir’s pressure drops, some form of “secondary recovery,” such as pumps or the injection of gas is required to increase the reservoir pressure and cause oil to flow. *Cf.* SPEIGHT, *supra* n. 2, at 146-50.

¹²² *See* *LEAF II*, 276 F.3d at 1256.

¹²³ *See id.* at 1257.

¹²⁴ *See id.*

¹²⁵ *See id.*

¹²⁶ 467 U.S. 837 (1984)

Congress is clear,” that intent must be given effect.¹²⁷ But if Congress has not spoken on the “precise question at issue,” a court should examine whether an agency’s interpretation of a statute “is based on a permissible construction of the statute.”¹²⁸ If the agency’s interpretation of the statute is reasonable, the agency’s interpretation should be upheld even if the court might have chosen a different statutory interpretation.¹²⁹

Utilizing the *Chevron* analysis, the Eleventh Circuit Court of Appeals determined that the phrase “relates to” created ambiguity in § 300h-4.¹³⁰ Accordingly, the court determined that Congress had not spoken unambiguously on the question of whether a state UIC program that regulates hydraulic fracturing can be approved under 42 U.S.C. § 300h-4.¹³¹ The EPA’s interpretation therefore was entitled to deference, and should be upheld, provided the interpretation was a reasonable one.¹³² The Eleventh Circuit Court stated it had “little trouble concluding” that the EPA’s position was based on a “permissible construction of the statute.”¹³³ Accordingly, it was permissible for the EPA to evaluate Alabama’s program under the alternative standards stated in 42 U.S.C. § 300h-4. EPA was not required to evaluate Alabama’s program under the more generally applicable standards stated in 42 U.S.C. § 300h-1 for approval of state UIC programs.¹³⁴

The court then moved on to LEAF’s second argument – that even if 42 U.S.C. § 300h-4 could be used to evaluate Alabama’s proposed program, the EPA should not approve Alabama’s proposed program because hydraulically-fractured wells are Class II wells and Alabama did not propose to regulate hydraulically-fractured wells as Class II wells.¹³⁵ Instead, Alabama proposed regulating

¹²⁷ *Id.* at 841.

¹²⁸ *See id.* at 843.

¹²⁹ *See id.* at n.11.

¹³⁰ *See LEAF II*, 276 F.3d at 1259.

¹³¹ *See id.*

¹³² *See id.*

¹³³ *See id.* at 1260.

¹³⁴ *See id.* at 1260–61.

¹³⁵ *See id.* at 1261–62.

hydraulically-fractured wells as “Class II-like” wells.¹³⁶

Alabama based that proposal on its conclusion that hydraulically-fractured wells were more like Class II wells than any other class of UIC wells, but that some Class II regulations were not appropriate for hydraulically-fractured wells.¹³⁷ Accordingly, Alabama’s UIC program regulated hydraulically-fractured wells as “Class II-like” wells.¹³⁸ LEAF argued that this was impermissible.¹³⁹ LEAF argued that hydraulic fracturing is an injection for the “enhanced recovery” of oil or gas, that hydraulically-fractured wells therefore are Class II wells, and hydraulically-fractured wells therefore must be regulated as Class II Wells.¹⁴⁰

The Eleventh Circuit Court ultimately agreed with LEAF. The court concluded that all injection wells had to be classified and regulated as one of the five classes of injection wells that federal regulations recognized at that time.¹⁴¹ Alabama had not done so. Instead, it had created a new class of wells – “Class II-like” wells. That conclusion would have been sufficient for the court to hold that Alabama’s UIC program did not satisfy federal requirements, but the court went on to address the category into which a hydraulically-fractured well did belong.¹⁴² Hydraulically-fractured wells clearly did not fit into Classes I, III, or IV. The court noted further that the EPA had never argued that hydraulically-fractured wells could fit into the catch-all category – Class V. Therefore, hydraulically-fractured wells fit “squarely” into the Class II category, and could not be regulated as “Class II-like” wells.¹⁴³

Neither the EPA nor LEAF argued that hydraulically-fractured wells would fit into the catch-all category of UIC wells – Class V, but the court’s statement that hydraulically-fractured wells fit “squarely” into Class II wells is arguably erroneous. Class II wells

¹³⁶ *See id.* at 1264.

¹³⁷ *See id.* at 1261–62.

¹³⁸ *See id.* at 1262.

¹³⁹ *See id.*

¹⁴⁰ *See id.*

¹⁴¹ *See id.* at 1263.

¹⁴² *See id.*

¹⁴³ *See id.*

include wells for the “enhanced recovery” of oil or gas.¹⁴⁴ The court reached this conclusion based in part on the fact that hydraulic fracturing is performed to increase or *enhance* recovery of oil or gas.

A strong argument can be made that the court’s reasoning was erroneous. In the oil and gas industry, the phrase “enhanced recovery” is a term of art that refers to particular types of operations. The phrase is not simply a way to refer to any type of *increased* recovery or *faster* recovery. Hydraulic fracturing does not fit within the meaning of the term of art “enhanced recovery.” The regulations are discussing a technical topic, thus “enhanced recovery” arguably should be read as a term of art.¹⁴⁵ Indeed, the EPA’s UIC regulations use a number of other phrases that clearly must be meant as terms of art, such as “secondary recovery” and “tertiary recovery,” because those particular phrases make little sense if the words are given their ordinary meaning. In the sentence where it appears, “enhanced recovery” can make sense whether the phrase is read as the term of art “enhanced recovery,” or the words in the phrase are given their ordinary meaning. In context, however, the phrase is best read as referring to the term of art.

If “enhanced recovery” were read as a term of art, then a hydraulically-fractured well would not be a Class II well. Instead, if a hydraulically-fractured well were considered an injection well at all, it would have to be categorized into the Class V catch-all category. That categorization could raise practical problems. In some states, Class II wells (all of which relate to the oil or gas industry) are regulated by an agency that regulates the oil and gas industry, while other classes of underground injection wells are regulated by another entity. An agency that regulates the oil and gas industry and Class II wells might be best positioned, by its expertise, to regulate hydraulically-fractured wells. However, classifying hydraulically-fractured wells as Class V wells might result in such wells being regulated by a different agency with less expertise on oil and as wells.

¹⁴⁴ See 40 C.F.R. § 144.6(b)(2) (2011).

¹⁴⁵ Cf. *LEAF II*, 276 F.3d at 1260 n.6. Ironically, *LEAF II* expressly recognized that “secondary or tertiary recovery” is a technical phrase that has a particular meaning within the oil and gas industry. See *id.*

D. The 2004 Report

Following the *LEAF* decision, the EPA decided to study the potential for hydraulic fracturing of coalbed methane wells to result in the contamination of USDWs.¹⁴⁶ The EPA focused on coalbed methane wells in part because those wells tend to be shallower and closer to USDWs than conventional oil and gas wells.¹⁴⁷ Indeed, many coalbeds that are targeted for coalbed methane production are actually within USDWs or immediately adjacent to USDWs.¹⁴⁸ Further, the Eleventh Circuit Court’s decision in *LEAF* had specifically concerned hydraulic fracturing in connection with coalbed methane production, and the concerns the EPA had heard citizens expressing about hydraulic fracturing arose from the use of hydraulic fracturing in coalbed methane (“CBM”) production.¹⁴⁹

The EPA designed its study to have “three possible phases.”¹⁵⁰ The goal of the first phase “was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into CBM wells and to determine, based on these findings, whether further study is warranted.”¹⁵¹ In Phase I, the EPA reviewed more than 200 peer-reviewed publications, interviewed approximately fifty persons from industry and state or local regulatory agencies, and communicated with approximately forty citizens and groups who had expressed concerns that the use of hydraulic fracturing in coalbed methane production had affected their drinking water wells.¹⁵²

The EPA produced a preliminary report in August 2002 and a final report in June 2004. The final report noted that there were numerous incidents in which persons believed their drinking water

¹⁴⁶ See EPA, EXECUTIVE SUMMARY, EVALUATION OF IMPACTS TO UNDERGROUND SOURCES OF DRINKING WATER BY HYDRAULIC FRACTURING OF COALBED METHANE RESERVOIRS ES-7 (June 2004) [hereinafter 2004 STUDY], available at http://www.epa.gov/ogwdw/uic/pdfs/cbmstudy_attach_uic_exec_summ.pdf.

¹⁴⁷ See *id.*

¹⁴⁸ See *id.* at ES-10.

¹⁴⁹ See *id.*

¹⁵⁰ See *id.* at ES-8.

¹⁵¹ See *id.*

¹⁵² See *id.*

wells had been contaminated by hydraulic fracturing operations, but the EPA “found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids.”¹⁵³ Further, “[a]lthough thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking wells had been contaminated by hydraulic fracturing fluid injection into CBM wells.”¹⁵⁴ The report stated: “Based on the information collected and reviewed, EPA has concluded that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs and does not justify additional study at this time.”¹⁵⁵ Thus, “continued investigation under a Phase II study is not warranted at this time.”¹⁵⁶ The EPA concluded that the removal of a large quantity of the fracturing fluids in the form of flowback is one reason that hydraulic fracturing poses little threat.¹⁵⁷ Other factors working to mitigate risks included dilution and dispersion, adsorption of fracking fluids onto coal, and potential for biodegradation of some constituents in fracturing fluid.¹⁵⁸

The EPA noted, however, that sometimes diesel fuel was being used as part of fracturing fluid.¹⁵⁹ The EPA stated that this was a matter of concern because diesel contains benzene, toluene, ethyl benzene, and xylene (“BTEX”).¹⁶⁰ These BTEX compounds are considered “potentially hazardous.”¹⁶¹ Although the EPA determined that hydraulic fracturing generally was not a threat to underground sources of drinking water, the EPA did believe that the use of diesel in particular was a source of concern. This concern was influenced by the fact that diesel contains BTEX compounds and that many

¹⁵³ *Id.* at ES-16.

¹⁵⁴ *Id.* at ES-1.

¹⁵⁵ *Id.*

¹⁵⁶ *Id.* at ES-16.

¹⁵⁷ *See id.* at ES-17.

¹⁵⁸ *See id.* at ES-17. Some commentators have criticized the study’s conclusions and argued that the study was too narrow in scope. *See, e.g.,* Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 *FORDHAM ENVTL. L. REV.* 115 (2009).

¹⁵⁹ *See* 2004 STUDY, *supra* note 146, at ES-1.

¹⁶⁰ *See id.*

¹⁶¹ *Id.* at ES-16.

of the coalbeds that were being fractured were found within or immediately adjacent to underground sources of drinking water.

The 2004 report stated that the EPA addressed its concern about BTEX by entering a memorandum of agreement with three companies that performed ninety-five percent of all CBM hydraulic fracturing to cease using diesel in hydraulic fracturing fluid injected into coalbed methane production wells that are located in USDWs.¹⁶²

E. The Memorandum of Agreement

In late 2003, prior to the issuance of the final draft of the 2004 report, the EPA entered a memorandum of agreement with the three companies that performed the vast majority of hydraulic fracturing in coalbeds, BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation.¹⁶³ In the agreement, which was signed in December 2003, the companies agreed to “eliminate diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs within thirty days of signing this agreement.”¹⁶⁴ The companies also agreed to notify the EPA “within thirty days after any decision to re-institute the use of diesel fuel additives in hydraulic fracturing fluids injected into USDWs for CBM production.”¹⁶⁵ The agreement provided that any party to it could withdraw from the agreement with thirty days written notice to the other parties.¹⁶⁶

F. The Absence of New Rule-Making

Neither LEAF nor the 2004 study prompted the EPA to modify its UIC regulations. In late 2004, the EPA’s Acting Assistant Administrator wrote a letter to Senator Jim Jeffords, answering questions that Jeffords had posed to the Agency. In its answers, the

¹⁶² *See id.* at ES-2.

¹⁶³ *See* Memorandum of Agreement between EPA and BJ Servs. Co., Halliburton Energy Servs., Inc. and Schlumberger Tech. Corp. (Dec. 12, 2003), *available at* http://www.epa.gov/safewater/uic/pdfs/moa_uic_hyd-fract.pdf.

¹⁶⁴ *Id.* at 5.

¹⁶⁵ *Id.*

¹⁶⁶ *See id.*

EPA explained why it had not enacted new regulations.

Q: Why did EPA choose to use an MOU as opposed to a regulatory approach to achieve the goal of eliminating diesel fuel in hydraulic fracturing?

EPA: While the report's findings did not point to a significant threat from diesel fuel in hydraulic fracturing fluids, the Agency believed that a precautionary approach was appropriate. EPA chose to work collaboratively with the oil service companies because we thought that such an approach would work quicker and be more effective than other approaches the Agency might employ.¹⁶⁷

The EPA's letter verified that, prior to *LEAF*, the EPA had interpreted the SDWA as not covering hydraulic fracturing, and seemed to imply that the EPA still did not interpret its regulations as covering hydraulic fracturing.

Q: In light of the court decision and the Agency's July 2004 response to the court remand, did the Agency consider establishing national regulations or standards for hydraulic fracturing or minimum requirements for hydraulic fracturing regulations under Class II programs?

EPA: When state UIC programs were approved by the Agency – primarily during the early 1980s – there was no Eleventh Circuit Court decision indicating that hydraulic fracturing was within the definition of “underground injection.” Prior to *LEAF v. EPA*, EPA had never interpreted the SDWA to cover production practices, such as hydraulic fracturing.

In light of the Phase I HF study and our conclusion that hydraulic fracturing did not present

¹⁶⁷ 151 CONG. REC. S7278 (June 23, 2005).

a significant public health risk, we see no reason at this time to pursue a national hydraulic fracturing regulation to protect USDWs or the public health. It is also relevant that the three major service companies have entered into an agreement with EPA to voluntarily remove diesel fuel from their fracturing fluids.¹⁶⁸

The EPA's continuing interpretation of its regulations as not covering fracturing seems to be verified by the fact that the EPA did not force states, other than Alabama, to regulate fracturing under the UIC programs. Environmental organizations understood that the EPA had failed to regulate, as those organizations made clear in their public statements. For example, one environmental group, the Oil and Gas Accountability Project, stated in a letter to Congress:

[T]he EPA and all states except Alabama have refused to regulate the toxics that are used during hydraulic fracturing operations. What this means, in practice, is that it is legal for hydraulic fracturing companies to inject toxic chemicals into or close to drinking water aquifers.

EPA does not currently regulate hydraulic fracturing, a common technique used to stimulate oil and gas production that can potentially compromise groundwater resources and reserves.¹⁶⁹

G. The 2005 Energy Policy Act

In 2005, the Congress enacted the Energy Policy Act. The Act contained numerous provisions,¹⁷⁰ including one that amended the SDWA to provide that the definition of “underground injection . . . excludes . . . the underground injection of fluids or propping

¹⁶⁸ 151 CONG. REC. S7278–79 (June 23, 2005).

¹⁶⁹ 151 CONG. REC. S7279 (June 23, 2005).

¹⁷⁰ See Energy Policy Act of 2005, Pub. L. No. 109-58 (2005) (codified throughout scattered sections of Titles 26 and 42 U.S.C.).

agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.”¹⁷¹ This legislatively overruled *LEAF* in part by expressly excluding application of the SDWA in situations in which the fracking fluid does not contain diesel.

The SDWA, as amended by the Energy Policy Act, does not expressly state that hydraulic fracturing constitutes an “underground injection” when the fracking fluid includes diesel fuel, but many people believe this result is implied by the Act’s provision that the definition of hydraulic fracturing “excludes” the use of fluids and proppants “other than diesel fuels.” Even after enactment of the Energy Policy Act, the EPA still did not amend its regulations to expressly address hydraulic fracturing.

VII. SDWA AND DEVELOPMENTS RELATING TO FRACKING

A. The EPA’s Website Post and the Resulting Litigation

By 2010, hydraulic fracturing was receiving substantial media attention, and was becoming controversial. At some point during that year, the EPA posted a page on its website with information regarding hydraulic fracturing. Among other things, the page stated:

While the SDWA specifically excludes hydraulic fracturing from UIC regulation under SDWA § 1421 (d)(1), the use of diesel fuel during hydraulic fracturing is still regulated by the UIC program. *Any service company that performs hydraulic fracturing using diesel fuel must receive prior authorization from the UIC program.* Injection wells receiving diesel fuel as a hydraulic fracturing additive will be considered *Class II* wells by the UIC program.¹⁷²

¹⁷¹ 42 U.S.C. § 300(h)(d)(1) (2008).

¹⁷² EPA, *Regulation of Hydraulic Fracturing by the Office of Water*, WATER: HYDRAULIC FRACTURING, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm#safehyfr (last updated May 4, 2012) (emphasis added).

Many people in the oil and gas industry were surprised. They had believed that the EPA and states had statutory authority under the SDWA to regulate hydraulic fracturing in which diesel fuel is used, but that neither the EPA nor the states (with few exceptions) had ever drafted regulations to do so.

Two industry groups, the Independent Petroleum Association of America and the U.S. Oil & Gas Association (collectively, the “IPAA”) filed suit in late 2010, challenging the EPA’s statement that companies must obtain a UIC permit before conducting hydraulic fracturing using diesel.¹⁷³ The IPAA’s challenge relies on the Administrative Procedures Act (“APA”).

B. The Administrative Procedures Act

The APA, among other things, defines the process required for federal agencies to adopt new regulations. The process generally requires that an agency publish notice of their proposed rules and give the public an opportunity to provide comments before the agency enacts final rules.¹⁷⁴ The notice and public comment “requirements are designed (1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review.”¹⁷⁵

However, there can be a hazy line between what constitutes a regulation that requires public notice and comment and what agency actions do not require notice and comment. The APA exempts from the public notice and comment requirement an agency’s “general statements of policy,” as well as its “interpretive rules” that do such things as provide guidance, instruct agency personnel how to interpret a particular regulation, and inform the public how the agency plans to administer a regulatory program.¹⁷⁶

¹⁷³ See Brief for Petitioners, *Indep. Petroleum Ass’n of Am. v. EPA* (D.C. Cir. 2011) (No. 10-1233), 2011 WL 2496293.

¹⁷⁴ See 5 U.S.C. § 553 (2010).

¹⁷⁵ See *Miami-Dade*, 529 F.3d at 1058.

¹⁷⁶ See 5 U.S.C. § 553(b)(3) (2010).

On the other hand, an agency's new or revised interpretation of its existing rules sometimes can have as significant an effect on regulated entities as the formal enactment of a new regulation.¹⁷⁷ Accordingly, courts have held that public notice and comment requirements must be followed even for actions that an agency may characterize as only guidance or explanation of policy.¹⁷⁸ An action or rule that requires notice and comment sometimes is called a "legislative rule."

The D.C. Circuit Court of Appeals often has been asked to distinguish between legislative rules, which require notice and comment, and interpretive rules, which do not, and the court has lamented the inherent difficulty in drawing that line.¹⁷⁹ Factors that will weigh in favor of an agency's actions being considered a "legislative rule," with notice and comment required, include an agency having revised a prior interpretation of a rule that was definitive,¹⁸⁰ the agency developing a new interpretation that is definitive, and instances where the agency's new guidance or interpretation imposes new obligations.¹⁸¹ Also, a rule is more likely to be deemed legislative when it "is based on an agency's power to exercise its judgment as to how best to implement a general statutory mandate."¹⁸² "[A]n agency can declare its understanding of what a statute requires without providing notice and comment, but an agency cannot go beyond the text of a statute and exercise

¹⁷⁷ See, e.g., *Env'tl. Integrity Project v. EPA*, 425 F.3d 992, 995 (D.C. Cir. 2005).

¹⁷⁸ See *id.*

¹⁷⁹ See, e.g., *Arizona v. Shalala*, 121 F. Supp.2d 40, 50 (D.C. Cir. 2000) (citing, *Syncor Int'l Corp. v. Shalala*, 127 F.3d 90, 93 (D.C. Cir. 1997)) (recognizing the difficulty in telling a substantive rule from an interpretive one); *Paralyzed Veterans of Am. v. D.C. Arena L.P.*, 117 F.3d 579, 587 (D.C. Cir. 1997); *Am. Mining Congress v. Mine Safety & Health Admin.*, 995 F.2d 1106, 1108-09 (D.C. Cir. 1993); *Am. Hosp. Ass'n v. Bowen*, 834 F.2d 1037, 1045 (D.C. Cir. 1987) (describing the distinction between the two types of rules as a "hazy continuum").

¹⁸⁰ "In determining whether an agency statement is a substantive rule, which requires notice and comment, or a policy statement, which does not, the ultimate issue is 'the agency's intent to be bound.'" *Viet. Veterans of Am. v. Sec'y of the Navy*, 843 F.2d 528, 538 (D.C. Cir. 1988).

¹⁸¹ See *Alaska Prof'l Hunters Ass'n, Inc. v. FAA.*, 177 F.3d 1030, 1034 (D.C. Cir. 1999); *Appalachian Power Co. v. EPA*, 208 F.3d 1015, 1028 (D.C. Cir. 2000).

¹⁸² *United Techs. Corp. v. EPA*, 821 F.2d 714, 720 (D.C. Cir. 1987).

its delegated powers without first providing adequate notice and comment.”¹⁸³

While there are no absolute criteria, the court is more likely to find a rule interpretive, rather than legislative, if it invokes “specific statutory provisions, and its validity stands or falls on the correctness of the agency’s interpretation of those provisions.”¹⁸⁴ If a rule merely clarifies existing statutory and regulatory duties, rather than spelling out new obligations, it may be considered interpretive and not subject to the requirements of notice and comment rulemaking.¹⁸⁵

A person can challenge an agency action on grounds that the agency has not followed procedures required by the APA, but one limitation on such challenges is that only “final agency actions” can be challenged.¹⁸⁶ The leading case on what constitutes a final agency action is *Bennett v. Spear*,¹⁸⁷ in which the United States Supreme Court held that, for an agency action to be final, it must “mark the ‘consummation’ of the agency’s decision making process,” and it must be one that determines “rights or obligations.”¹⁸⁸

C. The Parties’ Arguments and the Significance of the IPAA Litigation

The IPAA’s lawsuit petitions the United States Court of Appeals for the District of Columbia Circuit for judicial review of the EPA’s statement that companies must obtain a UIC permit before conducting fracturing operations in which the fracturing fluid contains diesel.¹⁸⁹ The IPAA argues that the EPA has improperly attempted to regulate by making a posting on its website, rather than following the rule-making process outlined by the APA.¹⁹⁰ In essence,

¹⁸³ *Fertilizer Inst. v. EPA*, 935 F.2d 1303, 1308 (D.C. Cir. 1991).

¹⁸⁴ *United Techs. Corp.*, 821 F.2d at 719–20.

¹⁸⁵ *Nat’l Family Planning & Reprod. Health Ass’n v. Sullivan*, 979 F.2d 227, 236 (D.C. Cir. 1992).

¹⁸⁶ *See* 5 U.S.C. § 701 (2010).

¹⁸⁷ 520 U.S. 154 (1997).

¹⁸⁸ *Id.* at 177–8.

¹⁸⁹ *See* Brief for Petitioners, *Indep. Petroleum Ass’n of Am. v. EPA* (D.C. Cir. 2011) (No. 10-1233), 2011 WL 2496293.

¹⁹⁰ *Id.*

the IPAA asserts that the website post constitutes a legislative rule that requires notice and comment.

The EPA argues that the website post merely described existing obligations under longstanding rules, and that therefore notice and comment was not required. In addition, the EPA has moved to dismiss, arguing that the court lacks jurisdiction to hear the IPAA's challenge because, the EPA argues, the website post was not a "final agency action."¹⁹¹

The IPAA replied by arguing case law establishes that an agency's change in interpretation of its own regulations does constitute a "final agency action" and can be challenged in court. The IPAA alleges that this amounts to the EPA clearly changing its interpretation. Prior to and during the *LEAF* litigation, the EPA's position always had been that the SDWA did not regulate hydraulic fracturing. Furthermore, the IPAA argues, case law makes clear that the EPA is not required to adopt the Eleventh Circuit Court's decision outside the Eleventh Circuit, and prior to 2010, the EPA had not.¹⁹²

The IPAA noted that, in 2005, the EPA informed Congress that, "current federal UIC regulations do not expressly address or prohibit the use of diesel fuel in fracturing fluids," and in light of this the EPA had no plans either to establish standards for determining whether states' UIC programs adequately regulate fracturing or to require states to monitor for the use of diesel in fracturing.¹⁹³ The IPAA stated it was unaware of any change in the EPA's position until 2010.¹⁹⁴ Thus, if the website posting was not itself a new

¹⁹¹ See, Brief for Respondent, *Indep. Petroleum Ass'n of Am. v. EPA* (D.C. Cir. 2011) (No. 10-1233), 2011 WL 2161921. Whether the EPA's web site statements rise to the level of final agency action is not discussed here, though case law supports that even an interpretive guidance issued without formal notice and comment rulemaking can qualify as final agency action. See, e.g., *Arizona*, 121 F. Supp.2d at 48.

¹⁹² See Reply Brief for Petitioners, *Indep. Petroleum Ass'n of Am. v. EPA* (D.C. Cir. 2011) (No. 10-1233) 2011 WL 2578549.

¹⁹³ See 151 CONG. REC. S7278 (daily ed. June 23, 2005) (The responses to Congress were contained in a letter from EPA's Acting Assistant Administrator Benjamin H. Grumbles to Senator Jim Jeffords, dated December 7, 2004.).

¹⁹⁴ See Reply Brief of Petitioners at 1, *Indep. Petroleum Ass'n of Am. v. EPA*,

regulation, the website posting constituted a change in the EPA's interpretation of its existing regulations, and thus was a "final agency action" which is subject to judicial review.¹⁹⁵

The IPAA also asserted that the EPA has approved UIC programs for most states, and has given each of those states primary SDWA enforcement authority within its borders. If a state's UIC program does not meet the EPA's minimum regulatory requirements, the EPA can rescind approval of that UIC program, but until the EPA does that, the UIC program still provides the SDWA regulations for that state. The IPAA states that the various state UIC programs do not require SDWA permits prior to fracking with diesel, and the EPA has not withdrawn approval of those UIC programs.¹⁹⁶

The EPA points to the 2005 amendment to the SDWA, which revised the SDWA's definition of "underground injection" to exclude "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."¹⁹⁷ The EPA argues that, through this amendment, Congress expressly clarified that hydraulic fracturing operations using diesel are subject to the existing requirements of the SDWA, including the statutory prohibition against underground injections not authorized by permit or rule.¹⁹⁸

The IPAA counters that while the Congressional amendment to the SDWA allows the EPA to regulate hydraulic fracturing using diesel fuels, Congress did not require such regulation, and further, neither the existing UIC regulations, nor the EPA's standing interpretation of the SDWA and the UIC regulations support the EPA's present position.¹⁹⁹

(D.C. Cir. 2011) (No. 10-1233) 2011 WL 2578549.

¹⁹⁵ See *id.* at p. 4-6.

¹⁹⁶ See Final Brief for Petitioners, *Indep. Petroleum Ass'n of Am. v. EPA* (D.C. Cir. 2011) (No. 10-1233) 2011 WL 2910515.

¹⁹⁷ 42 U.S.C. § 300h(d)(1)(A), (B)(ii) (2011) (emphasis added).

¹⁹⁸ See, Brief for Respondent, *Indep. Petroleum Ass'n of Am. v. EPA* (D.C. Cir. 2011) (No. 10-1233), 2011 WL 2161921.

¹⁹⁹ See Reply Brief of Petitioners at 1, *Indep. Petroleum Ass'n of Am. v. EPA*, (D.C. Cir. 2011) (No. 10-1233) 2011 WL 2578549.

Moreover, even if the 2005 Energy Policy Act was interpreted as requiring the EPA to regulate hydraulic fracturing under the SDWA whenever the fracking fluid contains diesel, that would not exempt the EPA from following the requirements of the APA. Thus, if the EPA's existing UIC regulations had not previously applied to hydraulic fracturing (and the IPAA asserts that the EPA itself had stated that its regulations did not apply to fracturing²⁰⁰), the EPA could not bypass the requirement of notice and comment, and simply declare that existing regulations now would begin to apply to fracturing, any more than the EPA could bypass notice and comment and write new regulations. Instead, the EPA would have to follow the APA's notice and comment requirements, whether it chose to write new regulations to govern fracturing or chose to assert that existing regulations, which had not previously applied to fracturing, now would begin to apply.

In resolving this litigation, a fundamental question facing the court was whether the EPA's website statement constitutes a legislative rule that is invalid because the agency did not institute APA notice and comment rulemaking procedures, or, instead, whether the website statement is merely interpretive of existing laws, thereby making it exempt from those procedures. Even if the EPA's web site statement is an interpretive rule, the inquiry does not necessarily end there. If an interpretive rule with binding effect were adopted without notice and comment, it would be upheld only if it qualified as an interpretation of an antecedent statute or legislative rule, and not if it were an act of independent policymaking.²⁰¹ Thus, a remaining question would be whether the EPA's past position that the SDWA and its UIC regulations did not require UIC permits for hydraulic fracturing operations constituted a definitive, binding

²⁰⁰ See Reply Brief of Petitioners, *Indep. Petroleum Ass'n of Am. v. EPA*, (D.C. Cir. 2011) (No. 10-1233) 2011 WL 2578549.

²⁰¹ See, e.g., *Orego Carabello v. Reich*, 11 F.3d 186, 195 (D.C. Cir. 1993) ("Ultimately, an interpretive rule simply indicates an agency's reading of a statute or rule."); *Gibson Wine Co. v. Snyder*, 194 F.2d 329, 331 (D.C. Cir. 1952) ("Generally speaking . . . 'regulations', 'substantive rules', or 'legislative rules' are those which create law, usually implementary to an existing law; whereas interpretive rules are statements as to what the administrator thinks the statute or regulation means.").

interpretation of the law.²⁰² If so, the EPA cannot amend or modify its prior interpretation except through APA notice and comment rulemaking procedures.²⁰³

Factors that weigh in favor of an agency’s prior interpretation of a rule being deemed “definitive” are if the interpretation has been upheld in a formal adjudication, if the interpretation has been endorsed by some other agency action having the force of law, and if the interpretation came from a source or sources who had the authority to bind the agency.²⁰⁴ Absent those factors, an agency’s change in interpretation may not require notice and comment.²⁰⁵

The resolution of this litigation will have significant implications for the regulation of hydraulic fracturing operations that use diesel fuel, though this appears to be a small fraction of fracturing operations. Perhaps more importantly, the case could have broader implications for the general regulatory process and challenges to that process. As the facts are described by the EPA, it merely posted information on its website about existing laws, and it would be “silly to permit parties to challenge an established regulatory interpretation each time it is repeated.”²⁰⁶ If one accepts the EPA’s characterization of its actions in this matter, a decision allowing such challenges to proceed in court certainly could lead to more frequent litigation.

The IPAA has alleged facts that reasonably could be interpreted as demonstrating that the EPA changed its interpretation of a regulation in a way that imposes new obligations, without notice and without following the usual rule-making process. It cannot be denied that different individuals, and different presidential administrations, can reach very different interpretations of the same statutes and regulations. A decision in *IPAA* that the EPA’s actions did not constitute “final agency action,” and that the court therefore lacks jurisdiction to hear IPAA’s challenge, could make it more difficult for citizens to challenge changes in a agency’s regulatory

²⁰² *Alaska Prof’l Hunters Ass’n, Inc.*, 177 F.3d at 1034–36.

²⁰³ *Id.*

²⁰⁴ *Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030, 1041 (D.C. Cir. 2009).

²⁰⁵ *Id.*

²⁰⁶ *Indep. Equip. Dealers Ass’n v. EPA*, 372 F.3d 420, 428 (D.C. Cir. 2004).

interpretations, even when the changes in interpretation have significant results.

VIII. IS A HYDRAULICALLY-FRACTURED WELL REALLY A CLASS II WELL?

The EPA website post challenged by IPAA declares that hydraulically-fractured wells will be regulated as Class II wells if the fracturing fluid contains diesel.²⁰⁷ And prior to the 2005 Energy Policy Act, *LEAF II* declared that hydraulically-fractured wells fit “squarely” with the scope of Class II wells. But is this correct?

Class II wells include three types of wells: (1) wells for the disposal of brine or produced water, (2) wells for the enhanced recovery of oil or natural gas, and (3) wells for the storage of liquid hydrocarbons. In determining that coalbed methane wells that are hydraulically fractured fit within the definition of Class II wells, the *LEAF II* court concluded that such coalbed methane wells are wells for the “enhanced recovery” of natural gas. In reaching this conclusion, the court apparently interpreted the word “enhanced” in the phrase “enhanced recovery” as an adjective that modifies “recovery,” and used the word’s ordinary meaning – namely, as a synonym for “increased” or “greater.”²⁰⁸

Fracturing can certainly be considered a method leading to increased recovery of oil or gas, but in reading “enhanced” as having its ordinary meaning, the court seemed to ignore another possibility – namely, that the phrase “enhanced recovery” should be given its technical meaning. The phrase “enhanced recovery” is a term of art in the oil and gas industry. The most prominent dictionary of oil and gas terms, the *Williams & Meyers Manual of Oil and Gas Terms*, defines “enhanced recovery” as “the increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool, . . . but does not include the injection in a well of a

²⁰⁷ EPA, *Regulation of Hydraulic Fracturing*, WATER: HYDRAULIC FRACTURING, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm#safehyfr (last updated May 4, 2012).

²⁰⁸ Cf. MERRIAM-WEBSTER’S NINTH NEW COLLEGIATE DICTIONARY, *supra* note 2, at 374.

substance or form of energy for the sole purpose of . . . stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.”²⁰⁹

The critical part of this definition is the provision that “enhanced recovery” does not include operations that are considered “stimulation.” Sources uniformly consider hydraulic fracturing to be a form of well stimulation. For example, the *Manual of Oil and Gas Terms* defines “stimulat[ion]” as including “fracturing.”²¹⁰ The *Shale Gas Primer* describes hydraulic fracturing as a type of “formation stimulation.”²¹¹ Robert T. Langenkamp’s *The Illustrated Petroleum Reference* also defines “stimulation” to include fracturing.²¹² Another source describes “hydraulic fracturing” as “a well stimulation method in which liquid under high pressure is pumped down a well to fracture the reservoir rock adjacent to the wellbore.”²¹³ Indeed, the EPA’s own SDWA regulations define “well stimulation” as including hydraulic fracturing.²¹⁴ Thus, under the *Manual of Oil and Gas Terms*’ definition of “enhanced recovery” which does not including “stimulation,” hydraulic fracturing would not be a form of “enhanced recovery.”

Other sources provide similar definitions of “enhanced recovery” that do not encompass hydraulic fracturing. One source defines “enhanced recovery” as an operation for the recovery of additional oil *after* “primary recovery”²¹⁵ operations.²¹⁶ A second source reaches a substantively similar definition by defining “enhanced oil recovery” as “the injection of fluids that are not found naturally in a producing reservoir down injection wells *into the*

²⁰⁹ See MANUAL OF OIL & GAS TERMS, *supra* note 6, at 296.

²¹⁰ See *id.* at 933. Under “well stimulation,” the MANUAL OF OIL AND GAS TERMS provides a cross reference to “stimulate.” See *id.*

²¹¹ See SHALE GAS PRIMER, *supra* note 6, at 56.

²¹² ROBERT T. LANGENKAMP, ILLUSTRATED PETROLEUM REFERENCE DICTIONARY 208 (1994).

²¹³ See HYNE, *supra* note 5, at 477.

²¹⁴ See 40 C.F.R. § 146.3 (2011).

²¹⁵ See MANUAL OF OIL & GAS TERMS, *supra* note 6, at 749 (“Primary recovery” has been defined as any recovery method that may be employed to produce oil or gas through a single well bore.).

²¹⁶ See, e.g., SPEIGHT, *supra* note 2, at 151–52.

depleted reservoir to recover more oil”;²¹⁷ a “depleted” reservoir is a reservoir from which an operator has recovered all of the oil or gas that can be recovered by “primary recovery.”²¹⁸ Hydraulic fracturing would not fall within either of those definitions of “enhanced recovery” because fracturing generally is used before a well begins production, not *after* primary recovery is complete. A third source also defines “enhanced oil recovery” in a way that does not appear to include fracturing.²¹⁹ Further, although the EPA’s SDWA regulations do not define “enhanced recovery,” 40 C.F.R. § 250.105 provides a definition of “enhanced recovery operations” that is consistent with industry’s meaning of “enhanced recovery.”²²⁰

Thus, within the oil and gas industry, “enhanced recovery” clearly is a phrase that has a technical meaning, and that meaning does not include hydraulic fracturing. This leads to the question of whether “enhanced recovery” should be given its technical meaning, as opposed to the words’ ordinary meaning. A sound argument can be made that the phrase “enhanced recovery,” as used in 40 C.F.R. § 144.6(b)(2), should be given its technical meaning. The UIC regulations are dealing with a technical subject, and words in regulations typically are given their technical meaning when the regulations deal with technical subjects. Indeed, *LEAF II* itself recognized this principle in discussing the meaning of “secondary and tertiary recovery.”²²¹ Further, the UIC regulations use other terms of art from industry, including “well stimulation,”²²² and other technical words and phrases from the oil, gas, and mining industries.²²³

²¹⁷ See HYNE, *supra* note 5, at 477.

²¹⁸ See *id.* at 439.

²¹⁹ LANGENKAMP, *supra* note 212, at 70.

²²⁰ 40 C.F.R. § 250.15 defines “enhanced recovery operations” as meaning “pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations that alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.” (2011).

²²¹ *LEAF II*, 276 F.3d at n. 8.

²²² See 40 C.F.R. § 146.3 (2011).

²²³ See, e.g., 40 C.F.R. § 144.6(b)(1) (“conventional . . . production”); *id.* § 144.6(b)(3) (“standard temperature and pressure”); *id.* § 144.6(c) (“[s]olution mining”).

If hydraulic fracturing were not a form of “enhanced recovery,” then *LEAF II*'s conclusion that hydraulically-fractured wells fit “squarely” into the UIC Class II category would be wrong. In that case, hydraulically-fractured wells either would be Class V wells (a catch-all category)²²⁴ or would not be covered at all by existing regulations. If such wells were not within the scope of existing regulations, that would frustrate the EPA's desire to regulate diesel used in hydraulic fracturing without having to go through a new rule-making process. On the other hand, if such wells were Class V wells, that would create undesirable results in some states, where different agencies handle the regulations for different classes of wells.²²⁵ In those states, the agencies that regulate Class II wells typically are the agencies that have the most expertise in oil and gas matters, yet hydraulically fractured oil and gas wells would be regulated by the agency handling Class V wells, which have less oil and gas well expertise.²²⁶

IX. EPA GUIDANCE

The EPA, working on the presumption that it will prevail in the *IPAA* litigation, began holding meetings with stakeholders in 2010 and accepting comments in order to generate guidance documents for the permitting under SDWA UIC regulations of wells in which hydraulic fracturing is conducted using diesel.²²⁷

²²⁴ This assumes that the fracturing fluid contains diesel. Under the post-*LEAF*, 2005 Energy Policy Act, hydraulic fracturing does not constitute an “underground injection” for purposes of the SDWA unless the fracturing fluid contains diesel. See 42 U.S.C. § 300h(d)(1)(B)(ii) (2011).

²²⁵ Alabama is an example. The EPA has granted SDWA primacy to Alabama as to all classes of underground injection wells, but the responsibility for administering Alabama's UIC regulations is divided between two agencies. The EPA approved a UIC program for Class II wells that is administered by the State Oil and Gas Board of Alabama, and approved a UIC program for all other classes of underground injection wells that is administered by the Alabama Department of Environmental Management. See C.F.R. § 147.50 (2011); see also *id.* § 147.51.

²²⁶ See *id.*

²²⁷ See EPA, *Stakeholder Involvement Strategy, Environmental Protection Agency*; WATER: HYDRAULIC FRACTURING, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroout.cfm#diesel (last updated May 4,

X. CONCLUSION

Hydraulic fracturing is a well stimulation technique used to facilitate production of oil or gas from formations with low permeability. In the process, a fluid is pumped into a formation at sufficiently high pressure that the formation fractures, creating additional pathways for the flow of oil or gas from the interior of the formation to the well bore. Hydraulic fracturing was developed in the late 1940s, and has been used in over a million wells since then.

In recent years, companies have combined the use of hydraulic fracturing and horizontal drilling to produce oil and gas from shale formations found in several parts of the country. This has led to increased use of hydraulic fracturing. Hydraulic fracturing has become the focus of significant media attention and has become controversial, with many people expressing concern that hydraulic fracturing may adversely affect underground sources of drinking water.

The primary federal law that protects drinking water is the Safe Drinking Water Act. For years, the EPA and regulated community interpreted the SDWA as not applicable to fracturing, but the United States Eleventh Circuit Court of Appeals ruled in the *LEAF* case in the late 1990s that the SDWA does apply to fracturing. In 2005, the Congress amended the SDWA to largely restore the EPA's prior understanding of the SDWA, providing the SDWA would not apply to hydraulic fracturing if the fluid used in the fracturing did not contain diesel fuel. Thus, if the fracturing fluid does not contain diesel, the SDWA does not regulate the fracturing operation.

The 2005 amendment to the SDWA has been widely interpreted as providing that the SDWA does apply to hydraulic fracturing when diesel is used in the fracturing fluid, but there has

2012); see also Keith B. Hall, *EPA to Provide Webinar Regarding Use of Diesel in Hydraulic Fracturing*, OIL & GAS LAW BRIEF (June 10, 2011), <http://www.oilgaslawbrief.com/hydraulic-fracturing/epa-to-provide-webinar-regarding-permits-for-use-of-diesel-in-hydraulic-fracturing-1/>. Final preparation of guidance did not begin until after the termination of the public comment process closed in the fall of 2010.

been significant disagreement about whether the EPA's existing SDWA regulations apply to fracturing. The EPA had never applied its regulations to hydraulic fracturing, except when forced to in *LEAF*, and even subsequent to *LEAF* the EPA seemed to continue to take the position that its regulations did not apply to fracturing. The EPA recently has taken the position that its SDWA regulations apply to wells that are hydraulically fractured with a fracking fluid that contains diesel. Two industry groups have challenged the EPA's position, arguing that the EPA's current position is a change that requires notice and comment pursuant to the rulemaking requirements of the Administrative Procedures Act.

The resolution of the industry groups' challenge will have immediate effects on the regulation of fracturing by determining whether the EPA can apply its existing regulations to hydraulically-fractured wells without providing for notice and comment. Further, the resolution may have broader effects on the somewhat murky jurisprudence regarding what agency actions must be preceded by notice and comment, and what agency actions may be challenged by persons believing they have been prejudiced.

