Regulatory Programs Governing Shale Gas Development

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The production of natural gas from shale is subject to environmental regulations, including a combination of requirements already followed by conventional gas developers, plus new ones specific to shale gas.

Environmental issues associated with shale gas development are regulated primarily by the U.S. Environmental Protection Agency (EPA), as well as by state agencies to which the EPA has delegated authority. Shale gas development is a segment of the oil and natural gas industry. The EPA has regulated this industry for many years, primarily under several significant environmental statutes:

- the Resource Conservation and Recovery Act (RCRA), which governs the management of solid and hazardous waste
- the Clean Air Act (CAA), which governs emissions of criteria and hazardous air pollutants, and greenhouse gases
- the Safe Drinking Water Act (SDWA), which applies to activities that could contaminate groundwater sources of drinking water
- the Clean Water Act (CWA), which governs discharges to U.S. surface waters.

These statutes and the EPA's related regulatory programs are discussed in more depth in Ref. 1. This article reviews their applicability to hydraulic fracturing and the EPA's approach to regulating the shale gas industry. Other statutes that might apply, such as the Toxic Substances Control Act (TSCA) and the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and other agencies' programs are not covered here.

Solid and hazardous wastes (RCRA)

The land footprint of shale gas development often includes surface impoundments that store recovered hydraulic fracturing fluids, which the industry recently began recycling. Prior to recycling, these fluids in surface impoundments are considered "recyclable materials," which the EPA

generally regulates as solid waste until the materials are actually recycled. EPA regulates solid waste (both hazardous and nonhazardous) under RCRA.

The EPA considers solid waste generated during exploration and production (E&P) of oil and gas to be lower in toxicity than other wastes covered by RCRA. Therefore, it exempted these E&P wastes under what it calls the RCRA E&P exemption. This exemption is not well understood by many in the field.

In general, RCRA-exempt E&P wastes are oil and gas drilling muds or fluids, oil production brines (produced water), and other wastes associated with the exploration, development, or production of crude oil or natural gas. The term "other wastes" refers to waste materials intrinsically derived from primary field operations — that is, activities occurring at or near the wellhead and before the custody-transfer point where the oil or gas is transferred for transportation away from the production site; it does not include



wastes generated during transportation or manufacturing.

At the well field, waste from downhole, or waste that was generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product, is likely to fall under the E&P exemption *(2)*. When custody of the product changes, the exemption is no longer applicable and the waste is once again subject to the RCRA hazardous-waste-management requirements.

In response to concerns regarding the release of chemicals used in hydraulic fracturing, the EPA is reconsidering the scope of the E&P exemption, particularly with respect to the storage and disposal of fracture fluid chemicals. The Agency is evaluating industry practices and state requirements, as well as the need for technical guidance on the design, operation, maintenance, and closure of chemical storage pits.

Although the EPA's existing RCRA E&P guidance can be interpreted to exempt recovered fracture fluid, new guidance on the application of RCRA to fracture fluid storage pits can be expected in the next few years.

Air emissions (CAA)

Oil and natural gas exploration and production involve many sources of emissions of:

• criteria air pollutants — carbon monoxide, particulate matter, ozone reported as volatile organic compounds (VOCs), nitrogen oxides, sulfur dioxides, and lead

• hazardous air pollutants (HAPs) — *e.g.,* benzene, ethylbenzene, toluene, xylene, *n*-hexane, formaldehyde, and acetaldehyde

• greenhouse gases (GHGs) — carbon dioxide, methane, and nitrous oxide.

Sources of these pollutants include drilling rigs and other equipment powered by engines, flares, compressors, separators, storage tanks, pneumatic pressure and temperature controllers, glycol dehydrators, sweetening units, and amine treatment systems. In addition, produced water and flowback fluids are sources of fugitive emissions. All of these sources of emissions are subject to the Clean Air Act.

Permitting. The CAA imposes preconstruction permit and operating permit requirements, as well as technology standards such as New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs).

CAA permit requirements are triggered by a facility's potential to emit criteria pollutants, HAPs, and GHGs. Prior to construction, operators of hydraulic fracturing systems must calculate their potential emissions to determine whether they will trigger major-source permitting requirements or qualify for a minor-source or general permit. Key to this determination are the definitions of stationary source and facility, which in turn determine whether the source is a major or minor one *(1)*.

A stationary source is any building, structure, facility, or installation that emits or may emit a regulated pollutant. Building, structure, facility, and installation refer to all the pollutant-emitting activities that: belong to the same industrial grouping; are located on one or more contiguous or adjacent properties; and are under the control of the same person. The more individual point sources (*e.g.,* engines, tanks, or wells) that are aggregated into a single stationary source, the higher the potential emissions will be. The higher the potential emissions, the more likely the source will be considered a major source. Major sources are subject to review under the Prevention of Significant Deterioration (PSD) program and may be required to apply the best available control technology (BACT), as well as Title V operating permit requirements.

In aggregating sources, the determination of contiguous and adjacent poses issues unique to the oil and natural gas industry, for instance when wells and tank batteries operated by the same entity are located large distances from each other. To address this, in 2009 the EPA revised its policy and reintroduced the concept of functional interdependence as an additional aggregation consideration, which could require aggregation over much larger areas than the 0.25 miles adopted by some delegated state agencies. Application of this concept has resulted in litigation and created considerable uncertainty for industry *(3)*. A permit issued by a state agency in a manner inconsistent with the EPA's interpretation of the CAA stationary source definition may draw litigation, risking permit challenge or subjecting the permitted entity to a citizen's lawsuit for constructing without a valid permit.

GHG emissions. Petroleum and natural gas producers

Multi-Agency Involvement

To implement the *Blueprint for a Secure Energy Future* issued by the White House in March 2011, the EPA, the Dept. of Energy (DOE), and the Dept. of Interior (DOI) established an interagency research program. The Multi-Agency Collaboration on Unconventional Oil and Gas Research will address the highest-priority challenges associated with safely and prudently developing unconventional shale gas and tight oil resources by focusing on timely science and technologies that support sound policy decisions by state and federal agencies responsible for ensuring the prudent development of energy sources while protecting human health and the environment (www.epa.gov/hydraulicfracture/oil_and_gas_research_mou.pdf).

In addition, the DOI's Bureau of Land Management (BLM) proposed new regulations governing hydraulic fracturing on public and Native American land that require disclosure of chemicals used in the process, increase wellbore integrity rules, and address flowback water issues (www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916).

are required to report GHG emissions to the EPA in accordance with the Mandatory Greenhouse Gas Reporting Rule *(4)*. This rule does not relate to permitting, but rather is a data-gathering exercise. Wells owned and operated by an entity within a single basin, or geologic province as defined by the American Association of Petroleum Geologists, constitute a facility for the purpose of the GHG reporting rule. Owners and operators must use specific emission calculation methods to determine actual emissions of carbon dioxide, methane, and nitrous oxide from pneumatic device and well venting during workovers, completions and testing, flares, storage tanks, compressors, dehydrators, pressure relief valves, pumps, flanges, instruments, etc. Facilities with emissions exceeding 25,000 metric tons of carbon dioxide equivalent (m.t. CO_2e) must report actual GHG emissions to the EPA annually.

New standards. On Apr. 17, 2012, the EPA adopted new and more-rigorous standards for oil and natural gas production facilities, with specific provisions applicable to hydraulic fracturing *(5)*. These include: NSPS for VOC, NSPS for SO_2, NESHAP for oil and natural gas production, and NESHAP for natural gas transmission and storage. The rules also impose for the first time requirements for oil and gas operations not previously subject to federal regulation, such as well completions at new hydraulically fractured natural gas wells and at existing wells that are fractured or refractured.

The new regulations require operators to reduce VOC emissions by capturing natural gas at the wellhead during well completion and separating the gas and liquid hydrocarbons from the flowback water that comes from the well as it is being prepared for production. This practice is called reduced-emission completion, or green completion. Capture must begin by Jan. 1, 2015; flaring is allowed until then. Refractured wells that employ green completions will not be affected by these rules as long as they meet recordkeeping and reporting requirements by the effective date of the rule. Flaring will be required for wells exempt from green completion requirements.

VOC emissions from condensate and crude oil storage tanks with a throughput of at least 1 barrel per day (bpd) of condensate or 20 bpd of crude oil must be reduced by 95%. Natural gas processing plants must implement a leak detection and repair program to control fugitive emissions. VOC emissions must also be reduced from: centrifugal compressors with wet seal systems; reciprocating compressors (which are required to replace rod packing to ensure that VOC does not leak as the packing wears); and high-bleed pneumatic controllers (the use of which is limited to only critical applications such as emergency shutoff valves).

The NESHAPs also establish air toxics emission limits for small glycol dehydrators at major sources; require all crude oil and condensate tanks at major sources to reduce their air toxics by at least 95%; and tighten the definition of a leak for valves at natural gas processing plants.

Power to the People

Most federal environmental statutes provide an opportunity for citizens to sue a regulated entity that fails to meet its permit requirements or other regulatory requirements. These citizen suits, in effect, put a federal district court in the shoes of the EPA or delegated state agency, and require a federal judge to review allegations of noncompliance and assess any penalties. A losing defendant pays penalties to the U.S. Treasury — and typically the prevailing plaintiff's legal fees as well.

Water resource law

The acquisition of water from surface or underground sources for hydraulic fracturing is governed by state law as a property right.

Very generally, in the eastern U.S., water law tends to follow the riparian view, where surface water rights are tied to ownership of the property adjacent to the water source. Western water law tends to follow the principle of prior appropriation, where surface water rights accrue to the first person to use the water for a beneficial purpose.

Groundwater is viewed as property of the landowner owning the surface over the groundwater. The amount of water that can be withdrawn is governed by: the rule of capture, which allows the landowner to capture as much groundwater as he or she can apply to a beneficial use; the riparian right rule, which sets the landowner's right to withdraw water based on the surface area of land owned; or the reasonable use rule, under which the landowner can withdraw an amount that does not damage the aquifer or surrounding wells.

Water property ownership can be divided (or disputed) when a landowner conveys the rights to minerals beneath the surface to another party, severing the mineral rights from the surface rights and creating what is known as a split estate. In the classic split estate, the mineral rights owner has the right to use as much groundwater or surface water as is reasonable for the development of the mineral right. However, this is a broad generalization, as the rights of the surface owner and the mineral rights owner are set by the conveyance document as well as by state law.

Owners and operators of hydraulic fracturing operations typically purchase water or lease water rights from water rights holders, and must comply with state water-use permitting requirements. The volumes of water utilized in hydraulic fracturing have created some conflict in areas impacted by drought, where water resources are perceived as limited.



Drinking water (SDWA)

Because oil and gas development occurs in part beneath the ground, and drinking water sources include groundwater, the EPA regulates some aspects of the oil and gas industry based on its SDWA authority to protect drinking water sources. The SDWA governs the injection of fluids into the ground, which the EPA implements through its underground injection control (UIC) program. The goal of the UIC program is to prevent contamination of underground sources of drinking water (USDW) from subsurface emplacement of fluid by well injection. A USDW is defined as an aquifer or portion of an aquifer that serves as a source of drinking water for human consumption or contains a sufficient quantity of water to supply a public water system, and that contains fewer than 10,000 mg/L of total dissolved solids *(6)*.

The goal of the UIC program is to prevent contamination of drinking water sources due to the migration of injected fluids from subsurface activities, for example, as a result of faulty well construction and leaking casing, faults or fractures in confining strata, nearby wells exerting pressure in the injection zone, injection directly into USDWs, or displacement of injected fluid into USDWs. The degree to which a USDW is threatened by these activities depends on the types and volumes of fluids being injected, the pressure in the injection zone and the overlying USDW, and the amount of injected fluid that could enter the USDW through one of the pathways. To address these concerns, the UIC program requires well operators to obtain permits and perform periodic mechanical integrity testing (among other things).

The UIC program regulates six classes of underground injection wells. Wells used for fluids associated with oil and natural gas production are designated Class II wells. Class II permits allow the following oil and gas-related injection activities *(7)*: injection of fluids brought to the surface in connection with natural gas storage, conventional oil production, or natural gas production; enhanced recovery of oil or natural gas; and storage of liquid hydrocarbons.

Owners/operators of Class II wells must conduct mechanical integrity testing every five years and demonstrate that there are no significant leaks or fluid movement in the wellbore. They must also demonstrate that they have properly constructed or plugged wells penetrating the injection zone. They are also required to submit plans for the eventual plugging and abandonment (P&A) of the wells with permit applications and a P&A report prior to closing any well. Wells must be located so they inject below an unfractured confining bed, and injection pressures need to be monitored and controlled to prevent fractures in the injection zone or confining bed. The fluids must not endanger or have the potential to endanger drinking water supplies, and owners/operators must submit inventories of fluids to be injected prior to injection. Finally, owners/operators must demonstrate that the proximity of injection wells to USDWs is appropriate, and conduct monitoring and testing to track future fluid migration.

EPA's SDWA authority for its UIC program specifically excludes the underground injection of natural gas for purposes of storage, as well as the underground injection of fluids or propping agents (other than diesel fuels) used in hydraulic fracturing for oil, gas, or geothermal production activities. However, the EPA does require UIC permits for the disposal of wastewater from fracturing operations via deep-well injection, as well as for fracture treatment processes that use diesel fluid.

On May 4, 2012, the EPA released draft guidance *(8)* for state permitting of hydraulic fracturing with "diesel fuel," which it defines to include diesel fuel, diesel No. 2, fuel oil No. 2, fuel oil No. 4, kerosene, and crude oil. Under this guidance, companies that perform hydraulic fracturing with fluids containing diesel fuel would have to receive prior authorization via a UIC Class II permit. In addition, the EPA has identified several aspects of fracturing with diesel fuels that will need to be considered in the permitting process, including the intermittent duration of the activity, high pressures, and long lateral fracturing lines.

Water discharges (CWA)

The Clean Water Act regulates the discharge of pollutants by point sources into U.S. surface waters. Facilities must apply for and receive a National Pollutant Discharge Elimination System (NPDES) permit prior to discharge.

The EPA has adopted technology-based requirements, known as best practicable control technology currently available (BPT) *(9)*, for discharges from oil and gas extraction facilities into surface water. BPT prohibits onshore hydraulic fracturing facilities from discharging 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). Thus, such facilities must instead utilize underground injection or evaporation pits and ponds.

EPA also regulates discharges to publicly operated treatment works (POTWs), better known as municipal wastewater treatment plants. In the past few years, shale

Additional Legal Liabilities

Compliance with statutory and regulatory federal and state environmental requirements generally does not insulate owners/operators of hydraulic fracturing operations from litigation arising from common law claims of trespass, nuisance, negligence, strict liability, restitution, and waste. These claims allow recovery for property damage, bodily injury, medical expenses, loss of profits, and punitive damage.

gas wastewater has been disposed of at POTWs that were not properly designed to treat these recovered fluids. If a POTW is not designed to treat recovered fracture fluids, it may result in a violation of its own NPDES permit. If so, the entity delivering the fracture fluids that caused the POTW to violate its permit is, in turn, in violation of the CWA pretreatment regulations. To address this issue, the EPA is gathering data and developing a proposed rule (scheduled to be released in 2014) for shale gas wastewater discharges.

The EPA is also updating its water quality criteria for chlorides, for NPDES-delegated states to use in issuing discharge permits. This standard is expected later in 2012 and will likely create additional permitting challenges.

While disposal of wastewater is important virtually everywhere hydraulic fracturing is performed, this issue is especially significant in the Marcellus Shale. On Mar. 17, 2011, the EPA's Office of Wastewater Management provided answers to frequently asked questions about natural gas drilling in the Marcellus Shale under the NPDES program *(10)* and shale gas extraction *(11)*. Although intended primarily to aid EPA regional offices and states in their regulatory and permitting efforts, this guidance can assist regulated entities with wastewater disposal and treatment.

Finally, the EPA regulates stormwater from oil and gas exploration, production, processing, treatment, and transmission operations, but only if the facility previously had a release of a reportable quantity or has contributed to a violation of a water quality standard *(12)*.

Closing thoughts

While oil and natural gas exploration and production, including hydraulic fracturing, have been regulated by the EPA and the states since the first environmental statutes were enacted, hydraulic fracturing has recently received particular scrutiny. Regulation and policy impacting hydraulic fracturing will continue to develop over the next several years, with significantly more public participation and regulatory transparency. To keep informed, visit the EPA's Natural Gas Extraction – Hydraulic Fracturing webpage *(13)* at www.epa.gov/hydraulicfracture and sign up to receive updates. CEP

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