Congressional Research Service

Memorandum October 14, 2008

TO: House Committee on Natural Resources
Attention: Wendy Van Asselt

FROM: Marc Humphries (Coordinator)
Analyst in Energy Policy
Resources, Sciences, and Industry Division

SUBJECT: Marcellus Shale Gas Development: Royalty Rates, Surface Owner Protection, and Water Issues

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This memorandum in response to your request for information on the Marcellus shale gas formation as it relates to the following three topics: 1) Royalty rates, rents, and signing bonuses that are paid to state and private landowners for shale gas leases; 2) State regulatory programs and surface-owner rights specific to shale gas; and 3) Federal and state laws and regulations that protect water quality and quantity (and potential "loopholes") specific to shale gas development. You requested that we provide you with information for all three topics above for the states of West Virginia, Pennsylvania, New York (Marcellus shale gas areas) and Texas (Barnett shale gas area). The memorandum below examines topics one and three, in that order. With respect to topic number two, CRS Energy Specialist, Adam Vann[1] in the American Law Division, concluded the following:

"Our research revealed only a brief mention of shale gas in the statutes or regulations of Texas, Pennsylvania, New York or West Virginia. Specifically, the New York code establishes certain spacing requirements for shale gas wells. These states do not appear to set forth any other protections or requirements that apply exclusively to shale gas mining."

I hope this information meets your needs. If you need any further assistance, please call me at 7-7264 or the other CRS Specialists at the numbers provided below.

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[1] Adam Vann (7-6978), American Law Division.

Shale Gas in the United States[2]

Gas shales are fine grained, organic rich, sedimentary rock. Natural gas is generated and stored in shales as free gas (which occupies pore space) or adsorbed gas (stored on organic matter). Gas shales are considered "unconventional" because the gas has not accumulated in a conventional porous reservoir. Commercial production of shale gas from organic shales requires either natural fractures or hydraulic fracture treatment[3] because of its low permeability. Recovery of gas from organic shales is typically around 10% of the gas resource in-place.[4]

Major gas shale basins exist throughout the lower-48 United States. According to a recent report by Navigant Consulting, there are at least 21 shale basins in more than 20 states[5] (see **Figure1**). Navigant, working for American Clean Skies, which is sponsored by Chesapeake Energy (one of the largest independent gas producers and the major gas shale producer), concluded that the Energy Information Administration (EIA) has 'chronically underestimated the unconventional gas resource base. At this time, EIA is updating its assessments with the best and latest available information (see EIA, *Is U.S. Natural Gas production increasing?*, June 11, 2008, available at: (http://tonto.eia.doe.gov/energy_in_brief/natural_gas_production.cfm).

U.S. domestic natural gas production has increased 6.8% since 2005, despite significant decreases in offshore production. Offshore production (U.S. Gulf of Mexico) decreased 11.6% from 2005 to 2007. The share of U.S. gas production from unconventional sources has increased steadily since 1990.

Gas shales have been a major contributor to this growth. For example, Barnett shale production was 94 million cubic feet per day in 1998. It has increased by more than 3000% to 3,014 million cubic feet per day in 2007. Navigant observed similar growth patterns, at earlier stages of development, at the Fayetteville, Haynesville, and Woodford shale plays. Expectations are that the Marcellus basin will be the next significant gas shale play. It appears potentially larger than the other basins already developed.

In the 'big 7' shale plays (Antrim, Barnett, Devonian, Fayetteville, Woodford, Haynesville, Marcellus), Navigant forecasts production reaching levels of 27 to 39 billion cubic feet per day within 10 to 15 years. Total U.S. average production in 2007 was about 55 Bcf/d. Leading shale gas producers include Chesapeake Energy Corporation, Devon Energy, XTO Energy, Inc., Southwestern Energy, Newfield Exploration Company, and Encana.

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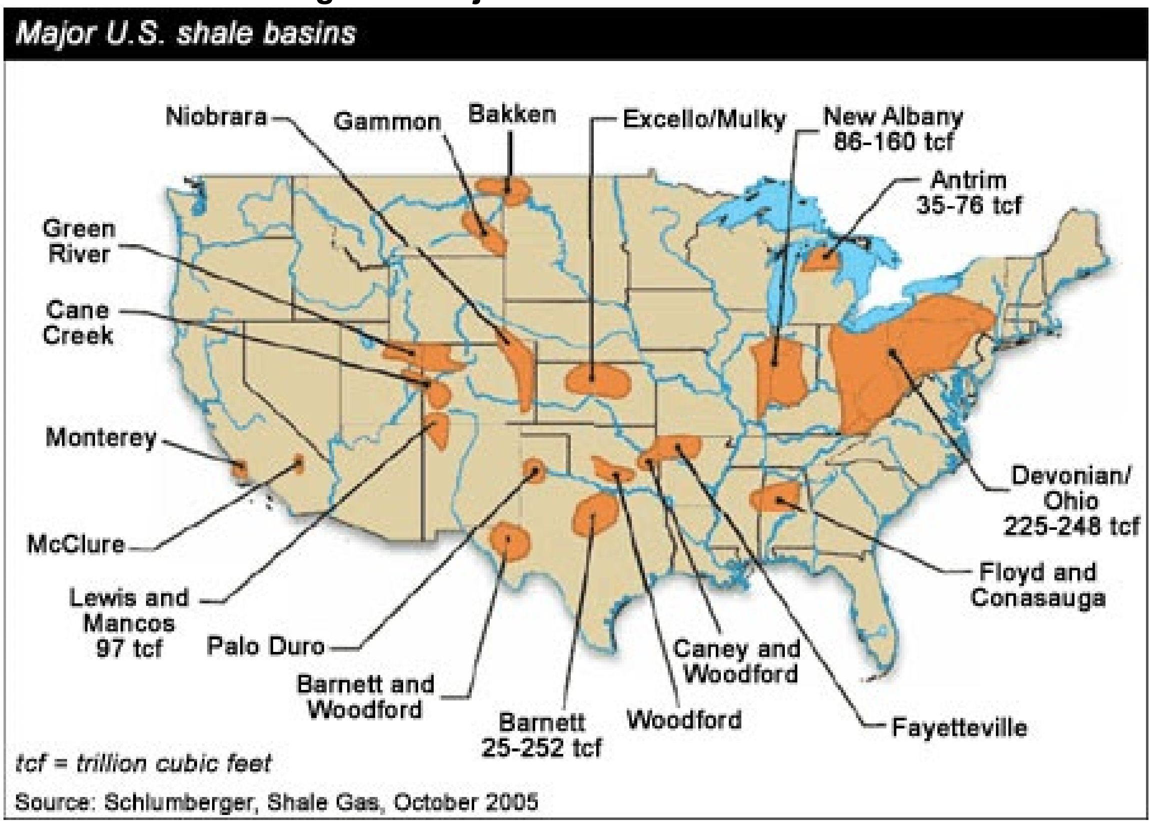
[2] Prepared by William F. Hederman (7-7738), Specialist in Energy Policy, Resources, Sciences, and Industry Division (RSI).

[3] Hydraulic fracturing is discussed on pp. 12-13 of this memo.

[4] *The Barnett Shale, Visitors Guide to the Hottest Gas Play in the United States*, Pickering Partners, Inc., October 2005.

[5] *North American Natural Gas Supply Assessment*, Prepared for Clean Skies Foundation, Navigant Consulting, July 4, 2008.

Figure 1. Major U.S. Shale Gas Basins



In 2006, the Bank of America estimated break-even costs for shale gas production to be within an estimated range of $4.20 to $11.50 per thousand cubic feet (Mcf). The estimated median break-even cost was $6.64 per Mcf.

Marcellus Shale Gas Formation[6]

The Marcellus shale is an organic rich "middle Devonian-age"[7] black low-density shale that lies beneath much of West Virginia, western and northern Pennsylvania, southern New York and eastern Ohio (see **Figure 2**). Most of the Marcellus shale gas is one mile or more below the surface. The thickness of the shale is not uniform throughout the formation as it varies from 50 feet to as much as 900 feet thick. Typically, the thicker shales, with greater organic material, yield more gas, and thus, are more economic. Horizontal drilling and hydraulic fracturing technologies along with high natural gas prices have helped generate a shale gas development boom (i.e., leasing and drilling) in the United States, including throughout the Marcellus shale formation. The Marcellus Shale, like most other shale gas formations, must be developed by using horizontal drilling versus using vertical drilling techniques (see **Figure 3**). Development, however, has been uneven in the Marcellus shale formation. Although production data are incomplete at best, reports indicate that New York

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[6] The Marcellus and Barnett Shale sections were prepared by Marc Humphries.

[7] Devonian-age refers to a geologic time of between 400 and 345 million years ago during the Paleozoic era.

and Pennsylvania lead the region with several producing wells, while West Virginia and Ohio have fewer producing wells.

In 2002, the U.S. Geological Survey (USGS) estimated the mean technically recoverable undiscovered natural gas resource potential for the Marcellus shale at around 2 trillion cubic feet (tcf). This estimate was based on little actual production at the time. A more recent and higher USGS estimate (225-248 tcf)for the Devonian/Ohio basin in Figure1includes the Marcellus Formation. The USGS estimate, however, is considerably lower than a 2008 "conservative" estimate of 516 tcf made by geoscience professors Terry Engelder (Pennylvania State University) and Gary Lash (State University of NewYork). The two professors believe that there could be at least 50 tcf of technically recoverable shale gas

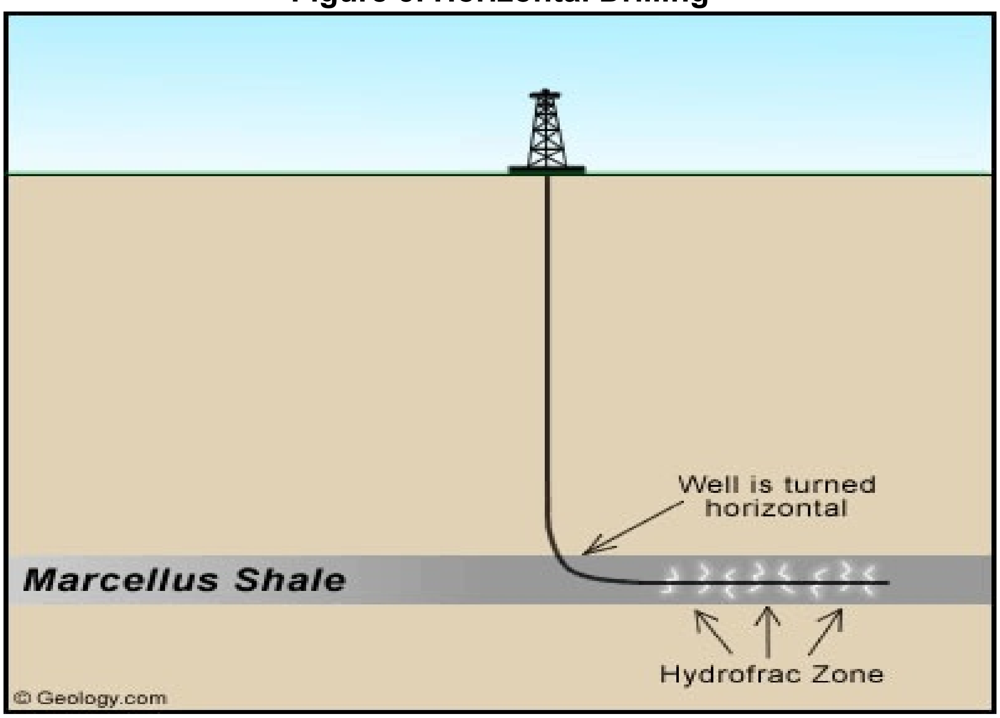
Figure 2. Marcellus Shale Distribution

resource potential in the Marcellus formation[8]

Barnett Shale Gas Formation

The Barnett shale formation is a Mississippian-aged shale [9]located near the Dallas/Fort Worth area of Texas, (primarily in the Fort Worth Basin covering 5,000 square miles at depths of 6,500-8,500 feet). The Barnett shale is a black shale with a high organic content. The USGS estimates the technically recoverable resource potential of the Barnett shale to be about 200tcf with a recovery factor of between 10%-15%. The Barnett shale play is reportedly the largest and most active natural gas play in the United States with about 173 rigs drilling. Further, according to Eric Potter, associate director of the Bureau of Economic Geology at the University of Texas at Austin, there are over 8,000 wells producing shale gas in the Barnett formation.[10]

Figure 3. Horizontal Drilling



Source: Geology.com

[8] "Marcellus Shale Play's Vast Potential Creating Stir in Appalachia," by Terry Engelder and Gary Lash, Professors of Geosciences, The American Oil and Gas Reporter, May, 2008.

[9] Mississippian-aged shale dates back to the Paleozoic era of around 345 to 320 million years ago.

[10] Personal communication with Eric Potter, Jackson School of Geosciences, University of Texas, October, 2008.

Framework for Landowner Compensation[11]

Landowners who also own the subsurface mineral rights may lease their land for the development of those minerals or sell the surface or mineral rights to qualified buyers for development. If the landowner decides to lease the land for mineral development, a lease agreement or contract is negotiated. Common features of oil and gas leases today include signing bonuses (or bonus bids for competitive lease sales), royalties, rents, primary lease terms and conditions for lease renewal. The factor payments (bonuses, rents, and royalties) that are made to the landowner are for the use of the land and the extraction of the minerals. If the landowner does not own the mineral rights or sells the mineral rights, a split-estate is established. Split-estate scenarios are common but are beyond the scope of this memorandum.

Federal Leases

The Mineral Leasing Act and the Outer Continental Shelf Lands Act, as amended, require that all public lands (onshore and offshore areas respectively) available for lease be offered initially to the highest responsible qualified bidder by competitive bidding. The objective of the competitive bid is to provide a "fair market value" return to the federal government for its resources. Under the two Acts mentioned above, the federal government requires royalties from oil and gas producers (and other resource producers) on leaseable federal lands and annual rents from non-producing lessees. Bonus bids (upfront payments made to obtain a lease) are collected on competitive oil and gas lease sales. The statutory minimum royalty rate for oil and gas leases on public lands is 12.5% or 1/8. Currently the royalty rate for onshore oil and gas leases is 12.5%, while the rate for an offshore lease can range from 12.5% to 18.75%. The most recent offshore lease sales, which brought in record bonus bids, were offered at 18.75%. Annual rental rates for onshore leases are established at not less than $1.50 per acre for the first five years of a ten-year lease and not less than $2 per acre each year thereafter. Annual offshore rents are between $5-$9.50 per acre depending on the depth of the water. The primary lease term for an onshore lease is 10 years and for an offshore lease is 5, 8, or 10 years depending on the depth of the water. Annual rent is paid until production begins. Royalties are then paid on the value of production.

Marcellus Shale Gas Leases

The Marcellus Shale gas formation has generated considerable interest within the past two years on state-owned and private lands throughout the Appalachian region in West Virginia, Pennsylvania, and New York. The state-by-state sections below describe how compensation to landowners atop the Marcellus shale has evolved over the past few years. The discussion below focuses primarily on bonus payments and royalties received by state and private landowners today compared to what they received just a few years ago. Rents are not part of the discussion because nearly all of the information available reports on signing bonuses and royalties. Further, rents are often rolled into signing bonuses, and paid upfront or paid quarterly as a "delay rental." Rents appear to be much less significant to small landowners who lease a few acres. On state and private leases, as with federal leases, rents

[11] Prepared by Marc Humphries.

would be paid until production commences, at which time royalties are paid on the value of production. See Tables 1 and 2 below for state-by-state comparisons.

New York. In 1999, signing bonuses for leases on private lands were around $5 per acre, with royalties rates at 12.5%. During that same time the state received between $15-600 per acre in bonus payments. In today's climate, bonus payments are as much as $3,000 per acre on privately-held lands with royalty rates between 15%-20%. Lease terms are typically 3-5 years with renewal clauses for continued production and shut-in wells. Less than 10 years ago, there were only about five or six companies involved but in 2008 there have been about 4 dozen companies (including Exxon/Mobil, BP, and Conoco Phillips) involved in securing leases for shale gas development projects. The Millennium Pipeline project being completed in southern New York could accommodate any increased shale gas production from New York and parts of Pennsylvania to serve the natural gas needs of the region.

Pennsylvania. In 2002, companies were paying signing bonuses of $25-$50 per acre and agreeing to $2 per acre annual rentals and 12.5% royalty on 10-year leases on state-owned land. Interest has grown dramatically since that time and firms are now paying as much as $2,500 per acre in bonus payments, 16% royalty and annual rental rates of $20 per acre for years 2-5 and $35 per acre in years 6-10. Private landowners have typically issued shorter term leases of 5-7 years. Private owners have received about $12 per acre in signing bonuses and a 12.5% royalty rate in 2003. In 2008, lessees are now paying private landowners signing bonuses of nearly $2,900 per acre with 17%-18% royalty rates on 5-7 year leases. As with many private leases rents are often calculated as part of the signing bonus and sometimes paid upfront or over a period of time.

West Virginia. Some landowners in West Virginia have seen their bonus bids climb from $5/acre in 2007 and early 2008, to more recent bonus payments of $1,000-$3,000 per acre. Royalty rates have increased from 12.5% (1/8) to 16%-18%. Rents are often included in the signing bonus or sometimes paid out in the form of a "delay rental." There are considered to be major obstacles to development in WV as in other states because of the terrain and the need for additional pipeline capacity and other support infrastructure.

Summary. All three states above have shown significant increases in the amounts paid as signing bonuses and increases in royalty rates. But there are still several lease sales as reported by the Natural Gas Leasing Tracking Service, that record signing bonuses in the $100-$200 per acre range because of greater uncertainty and less interest among natural gas companies and/or the lack of information among landowners on what the land is worth.[12]

There are several landowner organizations formed in recent years to pool land for leasing to gain leverage, advise landowners, and/or serve as information centers. Some groups seek out competitive bids from energy companies.[13]

[12] The Natural Gas Leasing Offer Tracking can be found at http://www.pagaslease.com/lease_tracking_2.php

[13] Natural Gas /Oil Landowner Groups Directory, http://www.pagaslease.com/directory_public.php

Barnett Shale Gas

Texas. The Barnett Shale is more established, less uncertain, and much of the necessary infrastructure is already in-place. Production has increased from less than 100 billion cubic feet in 2000 to about 700 bcf in 2006. There have been few if any dry holes on the Fort Worth Basin according to Robert Hatter of the Texas General Land Office (GLO).[14] Gas firms are paying between $10,000-$20,000 per acre in signing bonuses and between 25%-27% in royalty rates on private land. On these small, more predictable plays, there is great interest. The Barnett shale is a more difficult play in the Delaware Basin, where the state has some land that has been leased for shale gas development. The bonuses paid in the Delaware Basin were in the $350-$400 per acre range with 25% royalty rates. However, elsewhere, bonus bids for state-owned tracts were as high as $12,000 per acre. In recent times almost all royalty rates in Texas have been near 1/4 (25%). Those bonus bids grew from less than $1,000 per acre in the early 2000s while royalties were around 1/5 (20%).

Product Valuation and Verification[15]

Organizations involved with private-owned leases for shale gas development strongly recommend to lessors that they include provisions/clauses in their leases that require the producer to pay the wellhead price without deductions or to base the royalty on the gross proceeds at the well. Under most circumstances (in arms-length, third-party transactions), the wellhead is the point of first sale. Wellhead and spot prices are available from different sources including the EIA website. There are opportunities for a lessor to audit volume flows from the well but most often the producer will provide production and price data to the lessor. According to David McMahon of the West Virginia Surface Owners Rights Organization (WVSORO), there are major concerns among landowners that include the lessees deducting costs inappropriately, before the royalty is calculated. This practice has been known to deduct costs for transportation, compressors, and line loss from the wellhead price, thus reducing the royalty paid to the landowner. Typically, production is metered, but not necessarily audited. The cost of an audit may be cost prohibitive for small landowners.

The state of Pennsylvania audits production from the top 100 wells of its natural gas leases using an independent auditor. Audits may also be performed by "meter truck companies" that work for the shale gas producers. The state of New York requires that natural gas producers meter production and make that information available upon request.[16] The West Virginia Department of Environmental Protection, Office of Oil and Gas require an annual production report from all oil and gas producers in the state.

In Texas, all oil and gas production volumes on state land are reported to the Texas Railroad Commission. Producers on state lands must also report the value of production to the General Land Office (GLO). Proper valuation of shale gas is a continuing issue for the state and private landowners. Lawsuits are often filed by the state to address discrepancies in product values and royalty payments. Lawsuits by private landowners may be cost-prohibitive.

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[14] Personal communication with Robert Hatter, General Land Office, Texas, October 2008.

[15] Prepared by Marc Humphries, RSI Division.

[16] Energy Conservation Law, 23-0301-23-0305, Part 556.

Table 1. Shale Gas Bonus Bids, Rents, and Royalty Rates on Selected State Lands
(rates in percent)

	Statutory Minimum or Standard Royal Rate	Royalty Rate Range	Bonus Bids (per acre)	Comments
West Virginia[17]	12.5	-	-	No state shale gas leases
Pennsylvania[18]	12.5	12.5-16	$2,500	In many cases bonus bids were in the $25-$50 per acre range as recent as 2002. A royalty rate of 12.5% was most common.
New York[19]	12.5	15-20	about $600	Bonus bids ranged from $15-$600 per acre around 1999-2000 and most royalty rates were at 12.5%.
Texas	12.5	25	$350-$400 (Delaware Basin) $12,000 (river tracts)	Bonus bids have been relatively consistent in recent times (within the past 5 years). Royalty rates were more common at 20%-25% about 5 years ago. Most state-owned lands are not considered to be among the best sites for shale gas development.

[17] Personal communication with Joe Scarberry in the WV Department of Natural Resources, October, 2008.

[18] Personal communication with Ted Borawski in the PA Bureau of Forestry, who provided information on shale gas leases on both state and private lands, October, 2008.

[19] Personal communication with Lindsey Wickham of the NY Farm Bureau and Bert Chetuway of Cornell University, discussed lease sales on state and private land, October, 2008.

Table 2. Shale Gas Bonus Bids, Rents, and Royalty Rates on Private Land in Selected States

(rates in percent)

	Royalty Rates Range	Bonus Bids (per acre)	Comments
West Virginia[20]	12.5-18	$1,000-$3,000	Bonus payments were in the $5 per acre range as recently as 1-2 years ago. Royalty rates were 12.5%
Pennsylvania	17-18	$2,000-$3,000	
New York	15-20	$2,000-$3,000	
Texas	25-28	$10,000-$20,000	Bonus bids were in the $1,000 range around 2000-2001. Royalty rates were in the 20-25% range.

[20] Personal communication with David McMahon, Director of the WV Surface Owners Rights Organization, October, 2008.

Marcellus Shale Gas Development: Federal Law[21]

Development of gas in the Marcellus shale formation may be subject to regulation under several federal laws. In particular, large amounts of water are expected to be needed to hydraulically fracture and produce shale gas, and the use and disposal of this water and other wastewater associated with gas extraction may pose significant water quality and quantity issues. However, as with oil and gas production generally, this activity is regulated primarily under state laws. Key provisions of two relevant federal laws, the Safe Drinking Water Act (SDWA) and the Clean Water Act (CWA), are reviewed below.

Groundwater quality protection

Because of the low permeability of shale, the Marcellus shale formation must be treated to release gas contained in it. Hydraulic fracturing — "frac'ing"or "fracking" — is a commonly used treatment that involves the injection of fluids into wells to pressurize and fracture the shale in order to release the trapped gas. An oil and gas service company involved in the development of shale gas in Texas describes the importance of the process as follows:

> Shale gas wells are not hard to drill, but they are difficult to complete. In almost every case, the rock around the wellbore must be hydraulically fractured before the well can produce significant amounts of gas. Fracturing involves isolating sections of the well in the producing zone, then pumping fluids and proppant (grains of sand or other material used to hold the cracks open) down the wellbore through perforations in the casing and out into the shale. The pumped fluid, under pressures up to 8,000 psi, is enough to crack shale as much as 3,000 ft in each direction from the wellbore. In the deeper high-pressure shales, operators pump slickwater (a low-viscosity waterbased fluid) and proppant. Nitrogen-foamed fracturing fluids are commonly pumped on shallower shales and shales with low reservoir pressures.[22]

Consequently, development of the Marcellus shale is dependent on the use of hydraulic fracturing, which some fear could potentially impact underground aquifers that provide drinking water supplies. As discussed below, injection wells used for hydraulic fracturing were broadly excluded from coverage under the Safe Drinking Water Act in 2005, and thus are not subject to federal regulation.[23] However, the SDWA does not limit the authority of the states to impose their own laws and regulations,[24] and the protection of groundwater resources during oil and gas production activities has long been a responsibility of the states. For example, in New York, the Department of Environmental Conservation has authority over oil and gas development in the state, including oversight of hydraulic fracturing activities to ensure protection of groundwater resources. Further, while the injection of

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[21] The sections below were prepared by Mary Tiemann (7-5937), Specialist in Environmental Policy, Claudia Copeland (7-7227), Specialist in Resources and Environmental Policy, and Robert Meltz (7-7891), Legislative Attorney, American Law Division.

[22] Schlumberger, Inc., Shale Gas: When Your Gas Reservoir is Unconventional, So is Our Solution. Available at: [http://www.slb.com/media/services/solutions/reservoir/shale_gas.pdf].

[23] EPA retains the authority to regulate the use of diesel fuel for the purpose of hydraulic fracturing if the agency considers such regulation necessary to protect underground sources of drinking water.

[24] SDWA § 1414(e); 42 U.S.C. § 300g-3.

hydraulic fracturing fluids are not federally regulated, states such as Pennsylvania and New York do require submission of information on hydraulic fracturing fluid composition prior to well permit issuance.

Safe Drinking Water Act Authority

The underground injection control provisions of the Safe Drinking Water Act (SDWA) require the Environmental Protection Agency (EPA) to regulate the underground injection of fluids (including solids, liquids, and gases) to protect underground sources of drinking water.[25] Key provisions are outlined below.

- SDWA Section 1421 directs EPA to promulgate regulations for state underground injection control (UIC) programs, and mandates that the regulations contain minimum requirements for programs to prevent underground injection that endangers drinking water sources.[26]

- Section 1422 authorizes EPA to delegate primary enforcement authority (primacy) for UIC programs to the states, provided that state programs prohibit any underground injection that is not authorized by a state permit.[27]

- Section 1425 (added by the SDWA Amendments of 1980, P.L. 96-502) provides separate authority for states to attain primacy specifically for oil and gas (i.e., Class II) wells. The provision allows states to demonstrate that their existing standards for oil and gas wells are effective in preventing endangerment of underground sources of drinking water.[28]

Thirty-three states have assumed primacy for the UIC program; EPA has lead implementation and enforcement authority in 10 states, and authority is shared in the remainder of the states. Texas and West Virginia have assumed primacy for the UIC program

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[25] SDWA §1421 - §1426; 42 U.S.C. §§ 300h - 300h-5. The Safe Drinking Water Act of 1974 (P.L. 93-523) authorized the UIC program at EPA.

[26] § 1421(d)(2) states that

> underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons.

[27] P.L. 93-523, SDWA §1421 (42 U.S.C. § 300h).

[28] SDWA §1425(a) [33 U.S.C. § 300h-4] provides the following:

> For purposes of the Administrator's approval or disapproval under section 1422 of that portion of any State underground injection control program which relates to-
>
> (1) underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or natural gas storage operations, or
>
> (2) any underground injection for the secondary or tertiary recovery of oil or natural gas, in lieu of the showing required under section 1422(b)(1) the State may demonstrate that such portion of the State program meets the requirements of subparagraphs (A) through (D) of section 1421(b)(1) and represents an effective program (including adequate recordkeeping and reporting) to prevent underground injection which endangers drinking water sources.

(including primacy for injection wells associated with oil and gas development), while EPA implements the program directly for New York and Pennsylvania.[29]

The SDWA has long specified that the UIC regulations could not interfere with the underground injection of brine from oil and gas production or recovery of oil unless underground sources of drinking water would be affected.[30] In the Energy Policy Act of 2005, the 109th Congress amended SDWA UIC provisions to specify further that the definition of "underground injection" excludes the injection of fluids or propping agents (other than diesel fuels) used in hydraulic fracturing operations related to oil, gas, or geothermal production activities.[31]

The UIC program regulations specify siting, construction, operation, closure, financial responsibility, and other requirements for owners and operators of injection wells. EPA has established five classes of injection wells based on similarity in the fluids injected and activities, as well as common construction, injection depth, design, and operating techniques. UIC regulations are established 40 CFR Part 144.

In addition to these authorities, SDWA Section 1431 grants the EPA Administrator emergency powers to issue orders and commence civil action to protect public water systems or underground sources of drinking water.[32] The Administrator may take action when (1) a contaminant likely to enter a public drinking water supply system poses a substantial threat to public health, and (2) state or local officials have not taken adequate action.

Shale Gas Development and UIC Regulation. Injection wells associated with oil and gas production generally are categorized as Class II wells under EPA's UIC program. These wells are used to inject brines and other fluids associated with oil and natural gas production, and to inject hydrocarbons for storage.[33] Class II wells have been divided into three subclasses: enhanced recovery wells, disposal wells, and oil and gas storage wells.

The production of gas from the Marcellus Shale could involve the use of Class II injection wells to dispose of poor-quality produced water and other fluids associated with gas production. Class II disposal wells are regulated under the EPA UIC program, and can only be used to dispose of fluids associated with oil and gas production. EPA reports that most of the fluid injected into Class II wells is brine that is brought to the surface in the process of extracting oil and gas. This brine is often very saline and may contain toxic metals

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[29] To receive primacy, a state, territory, or Indian tribe must demonstrate to EPA that its UIC program is at least as stringent as the federal standards; the state, territory, or tribal UIC requirements may be more stringent than the federal requirements. For Class II wells, states must demonstrate that their programs are effective in preventing pollution of underground sources of drinking water (USDWs). Requirements for state UIC programs are established in 40 CFR §§ 144-147.

[30] SDWA §1421(d) specifies that "underground injection" does not include the underground injection of natural gas for storage purposes.

[31] P.L. 109-58, H.R. 6, Section 322, amended SDWA section 1421(d).

[32] 42 U.S.C. § 300i.

[33] Other types of wells occasionally are used for injecting produced water and brines. For example, if the produced water is used for solution mining or for an industrial process, it could be injected into a Class III or Class II well.

and radioactive substances. According to EPA, the brine "can be very damaging to the environment and public health if it is discharged to surface water or the land surface."[34] In order to prevent contamination of land and surface water bodies, Class II wells often are used to inject the brine back into the originating formation or into formations that are similar to those from which it was extracted. As states have adopted rules to prevent the disposal of brine to surface water and soil, injection has become the preferred way to dispose of this waste fluid.[35]

It is not yet known whether wells in the Marcellus formation will produce significant amounts of water, but the amount would be expected to vary across the region. However, because shale gas formations are generally impermeable, they typically produce much less water than traditional oil and gas fields or coal fields. Moreover, reinjection of any produced water into the same shale formation may not be feasible. Consequently, it is uncertain whether Class II disposal wells will be used to manage produced water in the Marcellus formation.

Surface Water Quality Protection

As previously described, hydraulic fracturing involves injecting water, sand, and chemicals into the shale layer at extremely high pressures in order to release the trapped natural gas. It is a water-intensive practice. Typical projects use 1-3 million gallons of water for each well and 0.5 million pounds of sand. Large projects may require up to 5 million gallons of water. The Texas Railroad Commission estimates that fracturing a vertical well in the Barnett shale in Texas can use more than 1.2 million gallons of water, while fracturing a horizontal well can use more than 3.5 million gallons.[36] Moreover, the wells may be re-fractured several times, thus requiring additional water. It is estimated that more than 5 million gallons of water are used each day in fracturing operations in the Barnett Shale in Texas.[37]

Some of the injected fluids remain trapped underground, but the majority of the produced water — 60 to 80% — is brought back to the surface during the drilling process. The water which is returned to the surface is called "flow-back." It typically contains sand, chemicals, and trace radioactive particles that are found in many geologic formations.[38] Chemicals used

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[34] U.S. Environmental Protection Agency, Underground Injection Control Program. Oil and Gas Injection Wells: Class II, at: [http://www.epa.gov/safewater/uic/wells_class2.html].

[35] The largest subclass of Class II wells are enhanced recovery wells. These wells are used to inject various substances (including brine, water, steam, polymers, and carbon dioxide) into hydrocarbon-bearing formations to recover primarily oil, but also natural gas, that remains in previously produced areas. Class II enhanced recovery wells are regulated under the UIC program, to the extent that they are not used for hydraulic fracturing purposes.

[36] Railroad Commission of Texas, Water Use in the Barnett Shale, July 30, 2008. Available at: [http://www.rrc.state.tx.us/division/og/wateruse_barnettshale.html].

[37] Burnett, D.B. and Vavra, C.J., Desalination of Oil Field Brine — Texas A&M Produced Water Treatment. August, 2006. Available at: [http://www.pe.tamu.edu/gpri-new/home/BrineDesal/MembraneWkshpAug06/Burnett8-06.pdf].

[38] These particles, termed normally occurring radioactive materials (NORMS), can be brought to the surface on drilling equipment and in fluids. Subsurface formations may contain low levels of such

(continued...)

in the fracking process may include toxic substances such as benzene, chromates, heavy metals, and other organic and inorganic compounds.[39] The flow-back must be reused (if possible); temporarily retained in open-air, lined retention ponds; or disposed of or treated. In addition, at the surface, the gas that has been released from the underground rock is separated from natural brine, or salt water, and the salt water also must be disposed of or treated. As noted previously, where feasible, the produced water may be disposed of through underground injection. However, although re-injection is commonly used in the oil and gas industry,[40] it is not clear that it is as readily used in Marcellus shale gas production because of the geology of the rock formation.

In the event that underground injection is not feasible in the area of the Marcellus shale, the produced water must be discharged to surface waters, and whoever disposes of the water is responsible for ensuring that the discharge does not violate a stream or lake's water quality standards. Established by states pursuant to Section 303 of the Clean Water Act (CWA), these standards protect designated beneficial uses of the waterbody, such as recreation or public water supply.[41]

Because of contaminants that are present in the produced water, it cannot be discharged to surface water without further treatment. An operator could provide treatment directly at the well site by constructing treatment facilities, but this is unlikely to be considered economic. It is more likely that the operator will transfer the wastewater off-site to an industrial treatment facility or a municipal sewage treatment plant that is capable of handling and processing the wastewater. In these cases, the operators of the publicly owned treatment works (POTW) or industrial treatment facility would assume responsibility for treating the waste and for discharging into a nearby receiving water in compliance with effluent limits contained in the facility's discharge permit.[42] Contaminants in the process water may cause operational problems for the biological material used by the POTW. Sewage treatment plants may require technology upgrades in order to take drilling waste, but costs of such upgrades may be prohibitive. If contaminants in the produced water pass through the POTW without adequate treatment, the discharge could violate the facility's discharge permit and could cause a violation of water quality standards.

Brine storage and transport have been identified as major issues in Barnett Shale development, and these are likely to be key issues in development of the Marcellus shale, as well. In Pennsylvania, currently there are five facilities designed to treat the type of industrial wastewater that is involved in producing shale gas. Most of the well sites are located in northeast Pennsylvania, while the closest treatment facilities are nearly 250 miles

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[38] (...continued)
materials as uranium and thorium and their daughter products, radium 226 and radium 228. The Marcellus shale is believed to be relatively more radioactive than other geologic formations.

[39] As noted, the 2005 Energy Policy Act broadly exempted the underground injection of fracking fluids from regulation under the Safe Drinking Water Act; thus, EPA does not request information on injected fracking fluids as it does with regulated injection practices (40 CFR § 144.27).

[40] In the Barnett Shale area, most of the water is reinjected for disposal.

[41] 33 U.S. C. § 1313.

[42] Under CWA Section 301, it is illegal to discharge pollutants into the nation's waters except in compliance with substantive and procedural provisions of the law, which include obtaining a discharge permit. 33 U.S.C. § 1311.

away.[43] Reportedly, one company with wells in the Marcellus shale in West Virginia has its hydraulic fracturing wastewater trucked to an out-of-state commercial facility that treats the water and then injects in into depleted oil and gas reservoirs.[44]

Other Surface Water Quality Issues. Another potential source of water pollution from oil and gas drilling sites is stormwater runoff that occurs during construction, as well as operation, of a facility. A particular concern in connection with stormwater runoff is sediment that may be transported during a rainfall or other wet weather event from the site to nearby water bodies. Provisions of the CWA regulate stormwater discharges from industrial and municipal facilities requiring implementation of pollution prevention plans and, in some cases, remediation or treatment of runoff.[45] Industries that manufacture, process, or store raw materials and that collect or convey stormwater associated with those activities are subject to the act's requirements.

However, the act specifically exempts the oil and gas industry from these stormwater management regulatory provisions. CWA Section 402(l)(2) exempts mining operations or oil and gas exploration, production, processing, or treatment operations or transmission facilities from federal stormwater regulations, and Section 502(24) extends the exemption to construction activities, as well.[46] Thus, federal law contains no requirements to minimize uncontaminated sediment pollution from the construction or operation of oil and gas operations. However, the federal exemption does not hinder states from requiring erosion and sedimentation controls at well sites, under authority of non-federal law. Pennsylvania, for example, requires well drill operators to obtain a permit for implementation of erosion and sedimentation controls, including stormwater management, if the site disturbance area is more than five acres in size. If the site is less than five acres, a plan for erosion and sediment control is required. Stormwater requirements are part of this permit.[47] New York has similar requirements for erosion and sedimentation controls at well sites, regardless of site area. The Delaware River Basin Commission, which has jurisdiction over water quality in a portion of the Marcellus shale formation (see following section) also has similar requirements regardless of site area.

Further, as described below ("Water Supply Management"), states and interstate agencies also regulate water quantity in the Marcellus shale region. For example, Pennsylvania and the Susquehanna River Basin Commission require water allocation permits for large withdrawals of surface or groundwater.

Marcellus Shale Gas Development: State Water Quality Laws

State laws regulating the quality of surface and ground water plainly would be implicated by Marcellus gas shale development. For example, in New York various aspects of such development would require a permit under the state's State Pollutant Discharge Elimination

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[43] Legere, Laura, "How to handle wastewater big challenge in gas drilling," The Citizens' Voice, Aug. 25, 2008.

[44] Kasey, Pam, *New Drilling Efforts Raise Questions*, The State Journal, August 14, 2008.

[45] Clean Water Act section 402(p); 33 U.S.C. § 1342(p).

[46] 33 U.S.C. § 1342(l)(2); 33 U.S.C. §1362(24).

[47] The Pennsylvania permit is called an Earth Disturbance Permit (ESCGP-1).

System (SPDES).[48] SPDES is an "approved," rather than delegated, version of the federal National Pollutant Discharge Elimination System (NPDES) because, while NPDES covers only discharges to surface water, SPDES covers discharges to groundwater also. The SPDES permit requirement could apply to the hydrofracking water migration under ground, unless four conditions are met, most importantly that the state determines that such injection will not result in the degradation of ground water.[49] The hydrofracking water removed from the ground following the stratum fracturing would likely be taken to a waste water treatment plant, where it would be governed by the plant's SPDES permit. SPDES permits would also cover treatment facilities built specially for the fracking water, if there would be discharges into a waterbody. The permit's discharge limits would be controlled in part by the applicable state water quality standards.[50]

As a second example, West Virginia's NPDES permit program would apply to waste water treatment plants to which backflow from Marcellus shale production sites was taken or to treatment facilities built specially for the fracking water that discharge into a waterbody.[51] The permit's discharge limits would be controlled in part by the applicable state water quality standards.[52] However, this program applies to surface water only, not groundwater, and the state's Groundwater Protection Act exempts "groundwater within geologic formations which are site specific to ... [t]he production ... of ... natural gas ...."[53] Fracking water reinjected at a second or subsequent production site would be covered under the state's underground injection control program.[54]

In addition to state water quality laws, there are also water quality requirements imposed by the interstate Delaware River Basin Commission, 36% of whose jurisdictional land area (in Pennsylvania and New York) is underlain by the Marcellus formation.[55] The Commission's water quality (and other) requirements are legally separate from those of the affected states — that is, obtaining state approval does not excuse an applicant from seeking Commission approval — though in some cases the two requirements may be substantively identical.

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[48] N.Y. Envtl. Cons. Law § 17-0505.

[49] N.Y. Code of Rules and Regulations (Conservation) § 750-1.5(a)(6).

[50] N.Y. Envtl. Cons. Law § 17-0501.

[51] W. Va. Code Ann. § 22-11-4(a)(16). See regulations at W. Va. Code of State Rules tit. 47, ser. 10.

[52] W. Va. Code of State Rules tit. 47, ser. 2.

[53] W. Va. Code Ann. § 22-12-5(i).

[54] W. Va. Code Ann. § 22-11-8(b)(7). See regulations at W. Va. Code of State Rules tit. 47, ser. 13.

[55] The compact creating the Delaware River Basin Commission was ratified by Congress: Pub. Law 87-328, 75 Stat. 688. Section 3.8 of the Compact states: "No project having a substantial effect on the water resources of the basin shall hereafter be undertaken by any person, corporation, or government authority unless it shall have been first submitted to and approved by the commission ...." Section 2.3.5 B of the Delaware River Basin Comm'n Administrative Manual (Rules of Practice and Procedure) lists 18 types of projects that must be submitted to the Commission, including withdrawal of groundwater and discharge of pollutants into surface or ground waters of the Basin. Codified at 18 C.F.R. § 401.35(b).

Another interstate-compact-created commission within the Marcellus region, the Susquehanna River Basin Commission, regulates only water quantity, not water quality.

Water Supply Management[56]

The procurement of the large volumes of water required for hydraulic fracturing must be arranged by the gas producers in advance of their drilling and development activity. Generally, water rights and water supply are regulated by states, if at all, but in the case of Marcellus Shale development, several interstate compacts will be relevant as well.

New York State is one example. The state's SPDES permit program (see section on state water quality laws) governs only water quality, not water quantity. With a limited exception for water pumping on Long Island,[57] there is no proactive regulatory scheme in New York for extraction of water from streams, lakes, groundwater, etc. If, however, the water is drawn from a public drinking water supplier, the state has limited authority to make sure that the public water supplier stays within its permit terms. Otherwise, however, the state can only *respond* to water flow problems – e.g., if a fish kill occurs, it can prosecute the responsible entity for violating the flow standard that is a component of the state's water quality standards.[58] There is no requirement that the government be notified in advance of an extraction of water.

As another example, the Texas Railroad Commission (TRC) regulates the use of surface water by oil and gas developers. The TRC language[59] states:

> "The industries regulated by the Commission use both surface water and ground water for their activities. In Texas, water flowing in Texas creeks, rivers, and bays is owned and managed by the State. Anyone who diverts such surface water must have authorization – or a water right -- from the State of Texas through the Texas Commission on Environmental Quality (TCEQ) (Texas Water Code, Chapter 11, relating to Water Rights). Therefore, a person who withdraws surface waters for mining, construction, and oil or gas activities must obtain a water rights permit from TCEQ.
>
> An applicant may apply for a Temporary Water Right permit for short-term use of surface water. Temporary Water Rights permits authorizing use of 10 acre feet or less and for one year or less may be issued by a TCEQ Regional Office. In times of drought, the TCEQ may suspend all temporary water rights permits.
>
> Applicants who seek to use more than 10 acre-feet of water or who seek a term of more than one year (up to a maximum of three years) must apply

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[56] Prepared by Robert Meltz and Gene Whitney, Section Research Manager, RSI.

[57] N.Y. Code of Rules and Regulations (Conservation) § 602.1.

[58] N.Y. Code of Rules and Regulations (Conservation) § 703.2. For certain classes of waterbodies, the flow standard prohibits any "alteration that will impair the waters for their best usages."

[59] Water use in association with oil and gas activities regulated by the railroad commission of Texas: http://www.rrc.state.tx.us/divisions/og/wateruse.html

> through the TCEQ Water Rights Permitting Team in Austin. TECQ forms, fees, contacts, and other water rights information may be found on the TCEQ website"

Other states apply surface and groundwater regulations similarly, and gas producers using fresh water for drilling and development must comply with state and local administration of water rights.

As for interstate constraints in the Marcellus Shale Gas region and vicinity, limits on quantity of water extracted are also imposed by the Delaware River Basin Commission[60] and Susquehanna River Basin Commission.[61] In addition, the Great Lakes-St. Lawrence River Basin Water Resources Compact,[62] currently under consideration by the Great Lakes states, prohibits inter-basin transfers of water.

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[60] 18 C.F.R. § 401.36.

[61] 18 C.F.R. § 806.23. *See also id*. at § 806.22 (standards for consumptive uses of water) and § 806.24 (standards for diversions). The compact creating the Susquehanna River Basin Commission was ratified by Congress: Pub. Law 91-575, 84 Stat. 1509.

[62] For the text of the compact, see

http:// www.cglg.org/projects/water/docs/12-13-05/Great_Lakes-St_Lawrence_River_Basin_Water_Resources_Compact.pdf.