MARCELLUS SHALE SAFE DRILLING INITIATIVE STUDY

PART III

FINAL REPORT
FINDINGS AND RECOMMENDATIONS

______ 2014

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Table of Contents

Tables

Figures

Executive Summary

Governor O'Malley's Executive Order 01.01.2011.11 established the Marcellus Shale Safe Drilling Initiative. Its purpose is to assist State policymakers and regulators in determining whether and how gas production from the Marcellus Shale in Maryland can be accomplished without unacceptable risks of adverse impacts to public health, safety, the environment, and natural resources. The Executive Order tasks the Maryland Department of the Environment (MDE) and the Department of Natural Resources (DNR), in consultation with an appointed Advisory Commission, with conducting a three-part study and reporting findings and recommendations. The completed study includes:

i. findings and related recommendations regarding sources of revenue and standards of liability for damages caused by gas exploration and production;

ii. recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland; and

iii. findings and recommendations regarding the potential impact of Marcellus Shale drilling in Maryland.

Part I of the study, a report on findings and recommendations regarding sources of revenue and standards of liability, in anticipation of possible gas production from the Marcellus Shale, was completed in December 2011. In July 2014, the Departments released Part II of the study, Interim Final Best Practices. This report represents Part III of the study, Findings and Recommendations.

This report synthesizes information from the work of the Departments and the Advisory Commission over the past three and a half years and presents the joint findings and recommendations of MDE and DNR, after consideration of the comments of the Advisory Commission. This work required a weighing of competing interests, including the rights of property owners to realize the value of mineral rights beneath their land, the positive impacts on the local economy, the value of the existing economies that are dependent on tourism and outdoor recreation, the possible climate change benefits, and protection of public health, the environment, and the quality of life enjoyed by the people of Western Maryland.

<u>Economic Impact</u>

At the maximum estimated rate of extraction over a period of 10 years, Allegany County could experience in the peak year as many as 908 new jobs, \$1.8 million in tax revenues and \$2.3 million in severance tax revenues. In its peak year, Garrett County could gain as many as 2,425 new jobs, \$3.6 million in tax revenues and \$13.5 million in severance tax revenues. Royalty payment to the owners and lessors of mineral rights could provide significant income. While these figures demonstrate an economic benefit, the actual effect on the economy could be mixed.

The amount of natural gas in Western Maryland is small compared to Pennsylvania's and West Virginia's holdings, and the economic benefits, especially the jobs, are likely to last only a few years. It is not clear whether the royalty payments would go to Marylanders, because in many cases the mineral rights were severed from the surface rights decades ago. Resource extraction typically operates on a "boom and bust" cycle, and jurisdictions that depend heavily on such industries often fail to diversify their economies, making them especially vulnerable when that industry leaves.

The economy of Garrett County, more so than Allegany County, is dependent on tourism and outdoor recreation, which could suffer during the active phases of gas development, even if no accidents or incidents occur. A large portion of Garrett County's revenue comes from real estate taxes on the land around Deep Creek Lake, and studies have shown that property values can decline sharply if drilling occurs nearby.

Public health, environmental and quality of life issues

Citizens of Western Maryland have raised legitimate questions about the likely impact of Marcellus Shale gas development on public health, the environment and quality of life. This report evaluates the key issues by explaining their significance, discussing the available information, and drawing a conclusion about Maryland's ability to manage the process.

There is no doubt that unconventional gas development in Western Maryland has the potential to harm public health, the environment and natural resources. Best practices and rigorous monitoring, inspection and enforcement can manage and reduce the risks. The Departments have proposed innovative and flexible methods that are expected to: reduce air pollution; protect soil, groundwater and surface water; properly regulate naturally occurring radioactive material mobilized by the drilling operations, require disclosure of chemicals while protecting legitimate trade secrets, minimize adverse impacts on habitat and natural resources, and address community concerns regarding noise, traffic, damage to roads, and the industrialization of the landscape. Based on information compiled by the Departments for the Advisory Commission, we believe that the influx of workers will be manageable, that housing will be available, that the emergency response and health care infrastructure will not be overburdened.

Conclusion

It is the judgment of the Department of the Environment and the Department of Natural Resources that provided all the recommended best practices are followed and the State is able to rigorously monitor and enforce compliance, the risks of Marcellus Shale development can be managed to an acceptable level. Some of the proposed best management practices have not been tested, and although we are confident that they will reduce the risks, some risks will remain, as is the case with all industrial activities. Best practices and rigorous monitoring, inspection and enforcement can reduce the risks to acceptable levels, but can not completely eliminate all the risks. Because knowledge and technology are continuously advancing, it will be necessary to adaptively manage shale gas development by requiring additional newly developed best management practices that provide improved protection for public health and the environment.

Section I: The Initiative

Governor O'Malley's Executive Order 01.01.2011.11 established the Marcellus Shale Safe Drilling Initiative. The Executive Order directs MDE and DNR to assemble and consult with an Advisory Commission in the study of specific topics related to horizontal drilling and hydraulic fracturing in the Marcellus Shale. The Advisory Commission was established to assist State policymakers and regulators in determining whether and how gas production from the Marcellus Shale in Maryland can be accomplished without unacceptable risks of adverse impacts to public health, safety, the environment, and natural resources. The Advisory Commission includes a broad range of stakeholders. Members include elected officials from Allegany and Garrett Counties, two members of the General Assembly, representatives of the scientific community, the gas industry, business, agriculture, environmental organizations, citizens, and a State agency. A representative of the public health community was added in 2013.

The Governor announced the membership of the Advisory Commission in July, 2011, and since its inception the Commission has held 34 meetings, all of which were open to the public. Most meetings were in Allegany or Garrett Counties, but several were held in Hagerstown, Annapolis and Baltimore. The Departments provided written information and briefings to the Advisory Commission on issues relating to high volume hydraulic fracturing (HVHF). Speakers representing the scientific community, industry and agencies from Maryland and other states presented information to the Advisory Commission and the Departments. The Commissioners were able to visit active drilling sites. The Departments consulted with the federal government and neighboring states regarding policy, programmatic issues and enforcement experiences. The Commissioners themselves, a well-informed and diverse assemblage, shared information and brought their expertise to bear.

The Executive Order tasked the Maryland Department of the Environment (MDE) and the Department of Natural Resources (DNR), in consultation with the Advisory Commission, with conducting a three-part study and reporting findings and recommendations. The completed study includes:

i. findings and related recommendations regarding sources of revenue and standards of liability for damages caused by gas exploration and production;

ii. recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland; and

iii. a final report with findings and recommendations relating to the impact of Marcellus Shale drilling including possible contamination of ground water, handling and disposal of wastewater, environmental and natural resources impacts, impacts to forests and important habitats, greenhouse gas emissions, and economic impact.

Part I of the study, a report on findings and recommendations regarding sources of revenue and standards of liability, in anticipation of gas production from the Marcellus Shale that may occur in Maryland, was completed in December 2011. The schedule was extended for the second and third reports.

In Part II of the study, MDE entered into a Memorandum of Understanding with the University of Maryland Center for Environmental Science, Appalachian Laboratory (UMCES-AL), to survey best practices from several states and other sources, and to recommend a suite of best practices appropriate for Maryland. The UMCES-AL recommendations were completed in February 2013 and made available to the Advisory Commission and the public. A draft of the Departments' report ("Draft Report") was made available for public comment on June 25, 2013. The recommendations in the Draft Report were very similar to those in the UMCES-AL Report. Where a UMCES-AL recommendation was rejected or modified, an explanation was provided. The comment period closed on September 10, 2013. More than 4,000 comments were received. Having considered all of the comments, including those of the Advisory Commission, the Departments released Part II of the study, Interim Final Best Practices in July 2014.

This report represents PART III of the study- Findings and Recommendations.

Section II: Marcellus Shale Gas Development

A. Shale Gas in Maryland

Oil and gas develop from organic material that settled in ancient water bodies and became buried and subjected to heat and pressure. Pressure, and heat through time may transform the organic material to oil, wet gas (a mixture of methane and liquid hydrocarbons), and dry gas. Overly-mature source rock contains mostly graphite and is probably not a good prospect for natural gas production.

Oil or gas may accumulate within permeable reservoirs beneath impermeable rock layers, from which it can flow naturally or be pumped to the surface through wells. These are referred to as conventional oil and gas reserves. Petroleum resources that cannot be exploited this way are termed "unconventional." In an unconventional reserve, the oil or gas is distributed throughout a relatively impermeable formation rather than in pools and does not readily flow because it is trapped in the pore spaces of the rock. Shale gas is an unconventional gas reserve.

There are two shale formations in western Maryland that could produce oil, wet gas and dry gas: the Marcellus and the deeper Utica. Although these formations have not been explored in Maryland, the portions of the Marcellus Shale in Garrett County and western Allegany County are thought to contain dry gas, while the portions of the Utica in Maryland are thought to be over-mature. Within Garrett County and westernmost Allegany County the Marcellus is between 5,000 and 9,000 feet deep (Brezinski) and the Utica shale is even deeper. The locations of the Marcellus Shale and Utica Shale are shown in Figure 1 (Source, Marcellus Shale Coalition).

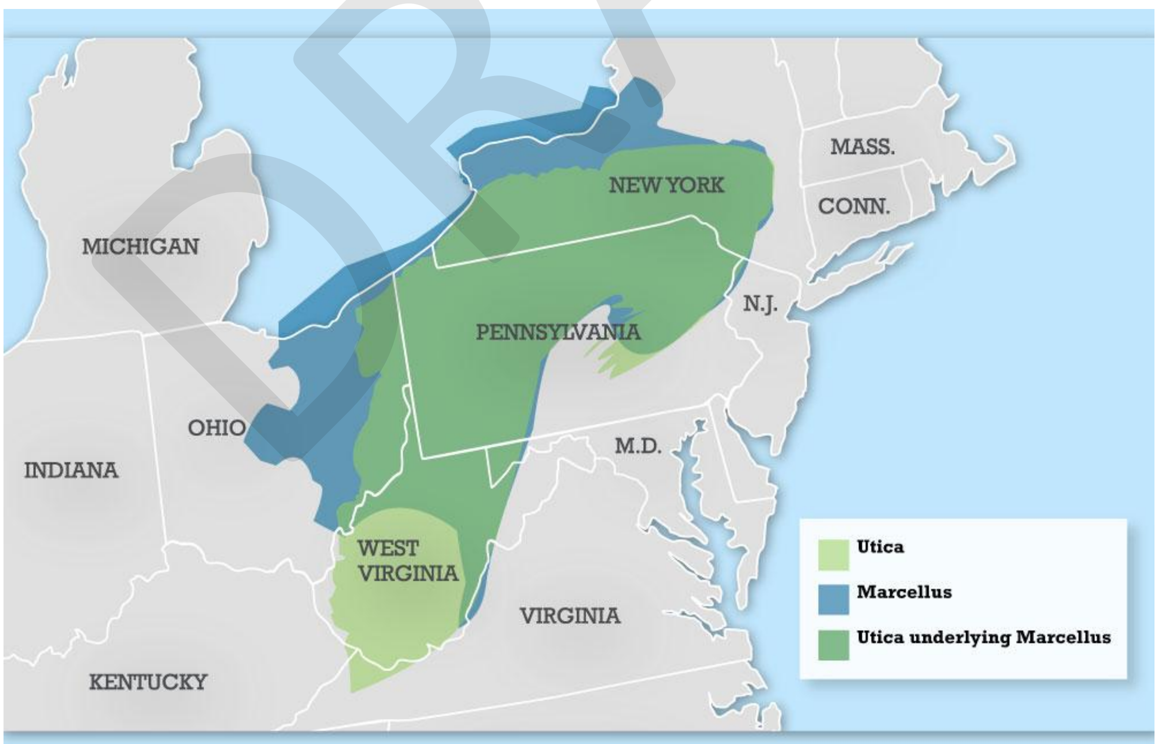

Figure 1. Locations of the Marcellus Shale and Utica Shale

The Marcellus Shale is thought to have been the source rock for the natural gas in the Oriskany Sandstone, which lies closely below the Marcellus in Western Maryland. Gas from the Oriskany was extracted in Western Maryland beginning in the 1940's and 50's, and the depleted reservoir today is used as a storage facility. Natural gas is injected back into the porous layers that once held natural gas, and it is withdrawn to meet peak seasonal demand. The storage field is near the town of Accident, in Garrett County.

There are other formations in Maryland that may contain oil and gas resources. Figure 2. Additional oil and gas basins in the Eastern United States, Source: (USGS, 2012).

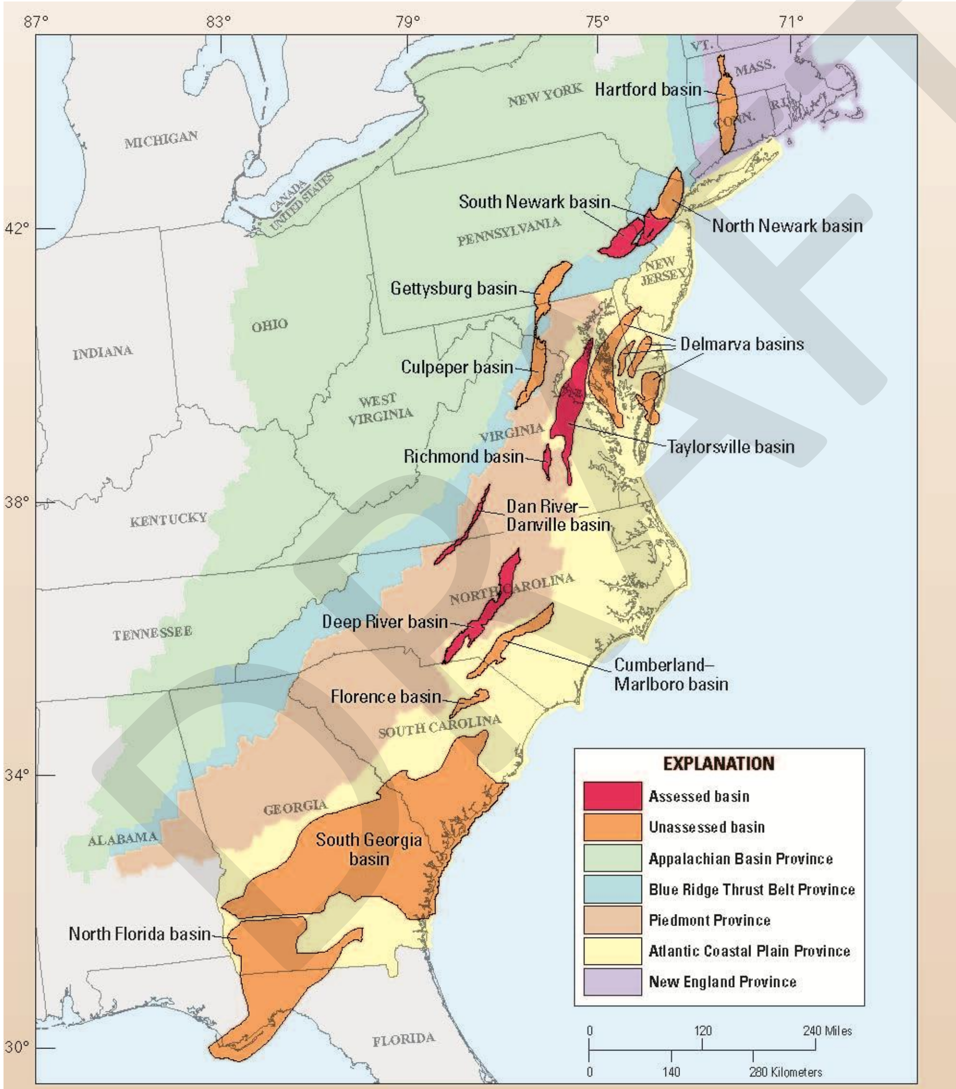

Figure 1. Map of the Eastern United States showing the locations of the five quantitatively (volumetrically) assessed East Coast Mesozoic basins, the nine basins that were not volumetrically assessed, and the U.S. Geological Survey province boundaries. Each basin includes one continuous gas assessment unit (tables 1, 2).

Figure 2. Additional oil and gas basins in the Eastern United States

The United States Geological Survey has assessed the Taylorsville basin, but not the Gettysburg, Culpeper or Delmarva basins in Maryland. The Marcellus Shale Safe Drilling Initiative addressed only the Marcellus Shale in Western Maryland. The findings and conclusions of this report may not apply to other basins.

B. Unconventional Gas Development and Production

Prior to conducting any drilling activities in a region, oil and gas companies routinely use seismic assessment surveys to target the best locations for drilling exploratory or production wells. Site preparation involves clearing, leveling, and excavation at a well site to install the well pad, pits for the storage of freshwater and wastes (if allowed), and any associated access roads.

After the site has been prepared and the drilling pad installed, one or more drill rigs are brought on site to conduct well drilling. The bore hole is drilled vertically until the bit approaches the Marcellus Shale, then the drill bit is turned gradually so that it enters the target formation, and drills horizontally through the shale for distances that can extend for more than a mile. The hole is cased and cemented. Typically, three levels of casing (surface, intermediate, and production) are used in a telescoping fashion. The surface casing is run from the land surface to below the deepest freshwater layer. The intermediate casing is run from the surface casing down to the target formation. The production casing is run from the intermediate casing through the target formation. All casing strings are cemented in place to stabilize the casing string and also seal the annular space between the casing and borehole to prevent gas or fluid migration between geologic strata.

Once drilling, casing and cementing are complete, the casing in the horizontal section of the well is perforated by a series of explosive charges that pierce the casing and cement and create small fractures in the target formation in preparation for hydraulic fracturing. Fracturing fluid, usually made up of about 90 to 95 percent water, chemical additives (about 0.5 to 2 percent), and about 8 to 9 percent proppant -- usually sand that is mainly silicon dioxide (about 8 to 9 percent), are pumped into the well at high pressure to further fracture the shale. Millions of gallons of fracing fluid are needed for each well. As the fracturing fluid penetrates and enlarges the initial fractures created by the explosive charges, the proppant fills the interstitial spaces of the created fractures and keeps them propped open so that produced gas can flow into the well. Once fracturing is complete, some of the injected fracturing fluids return to the surface as flowback. During the flowback period both hydraulic fracturing fluids and other naturally occurring materials contained in the formation migrate up the borehole to the surface as a result of the overlying geological pressure. Pipelines (gathering lines) that transfer the gas to intrastate or interstate pipelines can be installed during this phase.

Once the well is connected to a pipeline, on site compressors may be used to provide the pressure necessary to move the gas through the gathering lines. Offsite compressors are also required to maintain necessary pressures to deliver gas to processing plants or intrastate or interstate pipelines. In addition, produced gas may need additional processing to prevent condensation/crystallization of liquid compounds in the gas gathering lines. This processing may occur both on-site, known as field processing, and off-site at centralized processing plants.

The well may produce gas for decades. At the end of its useful life, an expandable device or cement must be placed in the well to prevent the movement of liquids and gas and the site must be reclaimed.

C. Laws and Regulations Affecting Shale Gas Development

Federal laws and regulations

The oil and gas industry is subject to control under the Clean Air Act and the Clean Water Act and is partially exempt from the Safe Drinking Water Act and the Resource Conservation and Recovery Act. Under the Clean Air Act, EPA issued regulations in 2012 that set new source performance standards for volatile organic compounds and sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. Some of these standards apply only to larger sources; for example, the performance standards for storage tanks apply only if the tank has a potential to emit 6 or more tons of volatile organic compounds a year.

Under the Clean Water Act, the direct discharge of wastewater from unconventional oil and gas extraction is forbidden, while sending the wastewater to Publicly Owned Treatment Works (POTWs) is subject to the general pretreatment regulations that forbid discharges that pass through or interfere with the processes of POTWs. EPA has announced that it is revising its regulations for the oil and gas extraction category and developing categorical pretreatment regulations. The proposal is expected by the end of 2014.

The Safe Drinking Water Act (SDWA) allows EPA to regulate the subsurface emplacement of fluid for storage or disposal; however, Congress excluded from regulation under the SDWA the underground injection of fluids (other than diesel fuels) and propping agents for high volume hydraulic fracturing. In 2014, EPA issued guidance clarifying the meaning of "diesel fuels" and the scope of this exception.

The Resource Conservation and Recovery Act establishes a framework for identifying "hazardous wastes" and setting standards for managing those wastes. Wastes from the exploration and production of oil and gas are exempt from classification as hazardous wastes because they were thought to be higher in volume and lower in toxicity than other wastes regulated as hazardous. These exempt wastes include drilling fluids, produced water, and other wastes associated with the exploration, development, or production of crude oil or natural gas. Some wastes generated at well sites are non-exempt, such as waste solvents and unused fracturing fluids or acids that are discarded.

State laws and regulations

Maryland generally incorporates the federal rules as they relate to oil and gas exploration and production. In addition, the laws relating to wetlands, stormwater, air permits to construct and permits to operate apply. Maryland laws also regulate the issuance of permits for drilling oil and gas wells.

Under the Environment Article of the Maryland Code, Title 14, Subtitle 1, a permit is required for the exploration, production, or underground storage of gas and oil; MDE is authorized to issue such permits. No permits may be issued to drill for oil or gas in the waters of the Chesapeake Bay, any of its tributaries, or in the Chesapeake Bay Critical Area. The Department is directed to deny the permit if it determines that: the proposed drilling or well operation poses a substantial threat to public safety or a risk of significant adverse environmental impact; the operation will constitute a significant physical hazard to a neighboring dwelling unit, school, church, hospital, commercial or industrial building, public road, or other public or private property; or the operation will have a significant adverse effect on the uses of a publicly owned park, forest or recreation area. The Department may place in a permit conditions which the Department deems reasonable and appropriate to assure that the operation shall fully comply with the requirements of the law, and provide for public safety and the protection of the State's natural resources. Additional restrictions are placed on the awarding of any oil or natural gas lease for production under lands or waters of the State (Natural Resources Article, Title 5, Subtitle 17). The systems for nomination of areas for leasing must be established by the Board of Public Works; however the Board has not adopted regulations governing leasing under State land or waters and no leases have been approved..

Local laws and regulations

Local laws on oil and gas production on matters addressed by State law are likely to be preempted by the State law. Zoning laws are not preempted. The Department must deny a permit if the applicant failed to receive applicable permits or approvals for the operation from all local regulatory units responsible for zoning (Environment Article, § 14-108(3)).

Section III: Work under the Initiative

A. Presentations and Briefings

Even before Governor O'Malley issued the Marcellus Shale Safe Drilling Initiative Executive Order, the Departments had gathered and reviewed a considerable amount of information about unconventional natural gas development. It was necessary to acquaint the Advisory Commission with the facts and the issues, which was accomplished over time by sharing documents and through briefing papers and presentations.

At the first meeting, the DNR Secretary discussed the interest the agency has about the longer-term impact of gas exploration and development on the landscape and resources of Western Maryland, particularly on land that the State owns or on which it has easements. Commissioners were encouraged to learn from studies already done. The MDE Secretary gave a comprehensive overview of the Marcellus Shale in Maryland, the opportunities and challenges, the existing regulatory programs, possible economic impacts, and concerns about public health, safety, social and community well-being, and the environment. Basic information about the natural gas industry and drilling, fracing, and transmission of shale gas was also provided. The genesis of the Marcellus Shale Safe Drilling Initiative Executive Order was explained, including the respective roles of the Departments and the Advisory Commission.

At subsequent meetings, the Departments provided briefing papers or presentations on a variety of topics, including bonding; insurance; royalties; severance taxes; standards of liability; presumptions of causation; trade secrets and chemical disclosure; Maryland's permitting and regulatory programs, including gas well permits, water appropriation, stormwater, erosion and sediment control, air pollution and air monitoring; groundwater in Western Maryland; waste disposal; wastewater treatment and disposal; naturally occurring radiation and technologically enhanced naturally occurring radiation; traffic; road damage; greenhouse gas emissions and health care burdens.

The Commission heard presentations by industry experts Glen Benge and Michael Parker on American Petroleum Institute Standards, industry practices generally, and drilling, casing and cementing, specifically. Mr. Parker also provided feedback on the proposed best practices. Steve Moore and John Arrell of ATK, an aerospace contractor, provided information on waterless fracing, using solid rocket fuel to fracture the shale.

John J. Clementson, II, with the Engineering Division of the Maryland Public Service Commission gave a presentation on the regulation of natural gas pipelines. John Quigley, a former Pennsylvania official discussed his experience with comprehensive planning to protect forest land and on the concept of the Comprehensive Gas Development Plan.

Keith Eshleman, Ph.D. and Andrew Elmore, Ph.D., of the University of Maryland Center for Environmental Sciences Appalachian Laboratory (AL) collaborated on a comprehensive survey of best practices and appeared at several meetings to provide briefings and answer questions. Representatives of Towson University's Regional Economic Studies Institute (RESI), including Daraius Irani, Ph.D., Jessica Daniels Varsa, Jade Clayton and Susan Steward attended meetings to provide updates, give presentations, and answer questions on their economic analysis of gas development in Allegany and Garrett Counties. Representatives of the Maryland Institute for Applied Environmental Health, including Dr. Donald Milton, Dr. Amir Sapkota, Dr. Sacoby Wilson, Dr. Thurka Sangaramoorthy and Laura Dalemarre and Meleah Boyle also attended meetings to give presentations on their health study and answer questions.

The Department of Natural Resources undertook a natural resource analysis and expanded its stream and groundwater baseline monitoring programs in Western Maryland. The Maryland Geological Survey (MGS) gave presentations on the geology of Marcellus Shale, the phenomenon of methane in drinking water wells, and fracture growth.

The Commission and representatives of the Departments were able to tour active drilling sites and completed well pads. Members of the Commission shared information and documents.

When Memoranda of Understanding were developed for a survey of best practices, the economic report, and the health report, the Commission was given an opportunity to comment on the work plan and development scenarios and was briefed periodically on the progress of the studies. The Commission was especially involved in the survey of best practices, with multiple presentations by the principal investigator. The Commissioners were invited to comment on the work plan for the risk assessment and to suggest risks to be evaluated.

Academicians and researchers gave presentations about their work: Anthony Ingraffea, Ph.D., Avner Vengosh, Ph.D., Zacariah Hildenbrand, Ph.D. and Charles Yoe, Ph.D. The topics included: risk assessments, risks of cement/casing failure, elevated levels of metals in groundwater in the vicinity of gas wells, and contamination of drinking water by stray gas and other substances.

All meetings were open to the public, and if time allowed, the public was allowed to ask questions of presenters and make comment. One evening meeting was held in Garrett County for the purpose of hearing from the larger community. There was also an email address for submitting comments at any time.

B. Studies by Contractors

Five projects were undertaken by outside contractors engaged by the State: a survey of best practices, a report on air monitoring data, a report on air emission control technology, an economic report, and a public health report. Funding for these studies was provided by the State of Maryland.

Survey of Best Practices

The Maryland Department of the Environment engaged Keith N. Eshleman, Ph.D., of the University of Maryland Center for Environmental Science – Appalachian Laboratory to survey best practices for shale gas development and recommend a suite of practices that would be appropriate for Maryland. The report was submitted to MDE in February 2013. MDE and DNR relied heavily on this report in formulating their recommended best practices.

Air Monitoring and Emission Controls (two studies)

The Air and Radiation Management Administration of MDE engaged Leidos, Inc., formerly SAIC, to prepare two reports. The first project was to compile a review of air monitoring activities or special studies to characterize ambient air quality impacts relevant to Marcellus Shale gas extraction and production activities. Leidos also agreed to make recommendations regarding ambient air monitoring, if Marcellus Shale gas production were to occur in Maryland. The report was issued in January 2014. The second Leidos report reviewed regulations and manufacturer design requirements for emission control equipment to be used during shale gas development and production. Leidos also made recommendations for emission controls in the final report, which was issued in January 2014.

Economic Report

The Maryland Department of the Environment engaged the Regional Economic Studies Institute of Towson University to prepare an impact analysis of Marcellus Shale gas development. A report was issued in May 2014 and a revised report was issued in September 2014. The report addressed economic and fiscal impacts, housing impacts, tourism-related impacts, infrastructure and road impacts, and other community impacts under three scenarios: no drilling, sufficient drilling to extract 25 percent of the Maryland Marcellus Shale gas, and sufficient drilling to extract 75 percent of that gas. Where sufficient data were available, the analysis was quantitative; otherwise, the impacts were qualitatively described.

Health Report

The Maryland Department of Health and Mental Hygiene (DHMH) entered into a Memorandum of Understanding with MDE to coordinate a study of potential public health impacts of natural gas development and production in the Marcellus Shale in Western Maryland. DHMH arranged for the study to be performed by the University of Maryland School of Public Health, Institute for Applied Environmental Health (MIAEH). The report, issued in July 2014, included a baseline health assessment, a hazard evaluation for air quality, impacts related to flowback and produced water, noise, earthquakes, social determinants of health, occupational health, and healthcare infrastructure. It also addressed cumulative exposures and risks and made recommendations for public health responses to the potential impacts.

C. Studies by MDE and DNR

In addition to preparing the first two reports, issued in December 2011 and July 2014, the Departments investigated specific issues and reported on the results to the Advisory Commission. DNR performed a constraint analysis to estimate how much of the Marcellus Shale in Western Maryland could be extracted by horizontally-drilled wells if the recommended location restrictions and setbacks that prevent installation of well pads were adopted. The study was included in the second report as Appendix D. DNR also addressed the impact of Marcellus Shale drilling on recreational and aesthetic resources in Western Maryland. In November 2013, DNR hosted a participatory GIS workshop to identify particular areas where recreational and aesthetic impacts would most likely intersect with shale gas development activities, as described in Appendix E of the second report. A formal justification for the aquatic habitat setback was presented in Appendix G of the second report. In cooperation with a consultant, DNR prepared a report entitled *The Case for Maryland's Proposed Comprehensive Gas Development Plan Program.*

The Maryland Geological Survey performed a pilot study of methane in groundwater. Its report, *Dissolved-methane concentrations in well water in the Appalachian Plateau physiographic province of Maryland,* was issued as Administrative Report 14-02-01.

DNR's Monitoring and Non-tidal Assessment Division (MANTA) developed and implemented a robust baseline monitoring plan for surface waters in western Maryland to locate and map sensitive species and their habitats; describe the range of seasonal and annual fluctuations in water quality, physical habitat condition, biological integrity and community composition; and document current thresholds for signature water chemistry parameters. The monitoring stations were established in areas associated with Marcellus Shale gas interests. MANTA also organized the Marcellus Shale Stream Monitoring Coalition[1] (MMC Program), a network of non-profit organizations, colleges, and interested citizens, with a goal of collecting weekly water quality and biological data from surface waters to help characterize baseline conditions and improve spatial coverage in the Marcellus Shale region. Seventy MMC volunteers are monitoring 64 stream reaches in Garrett County with direct oversight by MANTA staff. DNR developed a website, with an interactive map, that allows users to access the baseline surface water data collected by MANTA staff and MMC.

MDE provided a brief report on methane and greenhouse gas emissions. This topic was specifically mentioned in the Executive Order, and not addressed in any other report.

The Departments collaborated on a risk assessment. Dr. Charles Yoe of Notre Dame of Maryland University advised the Departments and gave a presentation to the Advisory Commission about how risk assessments are useful for making decisions under circumstances of uncertainty. Using available facts and identifying knowledge gaps, the probability of the occurrence of the harm and the magnitude of the harm can be estimated as high, medium or low. Risk is classified as acceptable, tolerable and unacceptable. Classifying the risk involves value judgments and political judgments. When a risk is not identified as acceptable, the question becomes whether there is a way to reduce the risk to make it tolerable. The work plan and list of risks to be evaluated were discussed with the Advisory Commission at public meetings. The draft risk assessment was released for public comment on October 3, 2014.

D. First Two Reports

First Report

The Marcellus Shale Safe Drilling Initiative Study: Part I, was issued in December 2011. As directed by the Executive Order, the Departments, in consultation with the Advisory Commission, addressed revenue and liability. The summary of the revenue recommendations was stated as follows.

[1] Maryland Department of Natural Resources, Stream Monitoring in the Marcellus Shale Region, www.dnr.maryland.gov/streams/marcellus.asp (Last accessed Nov. 17, 2014).

A successful revenue structure to offset the costs of State activities will protect the local economy, social well-being, public infrastructure, and natural environment; and internalize the costs attributable to gas exploration and production to individual operators where possible, and to the industry producing gas in Maryland where the impact cannot be attributed to a specific operator, or for which there is no solvent responsible entity. The Departments make the following recommendations regarding revenue:

R-1 The General Assembly should impose a fee on gas leases to fund studies of the issues set forth in the Executive Order.

R-2 The General Assembly should enact an appropriate State-level severance tax.

R-3 The severance tax revenue should be deposited into a Shale Gas Impact Fund to be used for continuing regional monitoring and to address impacts of gas exploration and production that cannot be attributed to a specific operator, or for which there is no solvent responsible entity.

R-4 The General Assembly should amend the law that limits the amount of a performance bond by deleting any reference to a dollar amount and directing MDE to establish the proper amount of bond by regulation, based on a consideration of the likely costs of complying with permit provisions, properly closing the well and performing site reclamation. (This recommendations was acted on by the General Assembly and is now in Maryland law, Chapter 568 of 2013.)

The discussion regarding liability was summarized as follows.

A liability system should be fair and equitable; promote the goals of environmental sustainability, public health, and safety; and incentivize the prevention of harm. The Departments make the following recommendations regarding liability:

L-1 The General Assembly should enact a law creating a rebuttable presumption that certain damages occurring close in space and time to exploration and production activities are caused by those activities, and an administrative process for requiring the permittee to remediate the damage, pay compensation, or both. (This recommendations was acted on by the General Assembly and is now in Maryland law, Chapter 703 of 2012.)

L-2 The General Assembly should enact a comprehensive Surface Owners Protection Act.

L-3 Community impacts should be addressed through mediation or by use of community benefits agreements.

Second Report

To prepare The Marcellus Shale Safe Drilling Initiative Study: Part II: Interim Final Best Practices, the Departments drew heavily from the UMCES-AL report, the expertise of its staff, research and information presented at Advisory Commission meetings. The draft second report was released for public comment in August 2013. More than 4,000 comments were received. The Interim Final Best Practices report was finally released in July 2014. Appendix B contained the comments of the Advisory Commission and Appendix C (147 pages) provided responses to the public comment. Changes had been made to the draft in response to suggestions from the Commission and from the public.

This report was "Interim Final" because the Departments acknowledged that the best practice recommendations could change as a result of the health report and the risk assessment, which had not yet been completed. Notable features of the recommended best practices were:

A Comprehensive Gas Development Plan (CGDP). A prospective applicant for a permit to drill a gas well must submit for approval a plan covering at least 5 years of activity, so that landscape level and cumulative adverse impacts might be avoided or mitigated. An approved CGDP is a prerequisite for filing an application for an individual well permit.

Location Restrictions and Setbacks. To protect people and the environment, the location of a well pad in certain areas was prohibited. Where a well pad or other infrastructure is allowed, setbacks from sensitive receptors are defined.

Engineering, Design and Environmental Controls and Standards. Minimum standards for construction, sediment and erosion control, transportation, water withdrawal, storage and reuse, drilling, casing and cement, chemical disclosure, air emissions, waste and wastewater treatment and disposal, protection against light, noise, and invasive species, leak detection, site security and closure and reclamation were established.

Application for a Permit to Drill. Following approval of the CGDP, a person may apply for a permit to drill a well. The application must be consistent with the CGDP and include a plan for construction and operation that meets or exceeds the enumerated controls and standards. The application must include an environmental assessment and two years of monitoring in the vicinity of the well site to establish background conditions.

As a result of the MIAEH health report and the Departments' risk assessment, additional best practices have been identified. They are:

1. Noise modeling must be included as part of the plan to comply with noise standards.

2. Noise reduction devices must be installed on all equipment at the drill site.

3. The number of truck trips to deliver material to the well pad and remove wastes and the impact of the remaining trips must be reduced by the following methods, if they are practicable for the specific site: establish a centralized water storage facility at a location that minimizes the use of roads near homes or other occupied buildings for the truck transportation of water to the

centralized water storage facility; upgrade the roads to be used so that damage to the roadways is minimized; transfer water from the centralized storage facility to the well pad using aboveground temporary hoses or pipes; establish a centralized facility with all the equipment necessary for preparing and pressurizing the fracturing fluid in a location, and with sound and air pollution controls that minimize impacts to people, and deliver the water, proppant and additives to the well pad using pipes; and if they are proven to be safe and effective and have less impact, perform fracturing using alternatives to high volume water-based fracturing fluid.

4. If feasible, one or more semi-permanent water supply access points with large capacity and storage options should be established to decrease risks related to water withdrawals on sensitive headwater streams and Use III and Tier II waters.

5. The capacity of the zero-discharge drill pad must be enlarged to contain at least the volume of a 25 year, 24 hour storm event.

6. At least two vacuum trucks will be required to be on standby at the site during drilling, fracturing, and flowback so that any spills occurring during those stages, which could be of significant volume, could be promptly removed from the pad.

7. The option to allow a variance of the 2,000 foot setback from a private drinking water well based on the consent of the owner of the drinking water well should be eliminated.

8. Additional modeling for water withdrawal impact assessment in sensitive locations, such as Use III and Tier II waters, will be required.

9. MDE and DNR will develop additional scientific guidance for monitoring and assessing potential ecological impacts to sensitive streams as a result of water withdrawals.

Section IV: Principal Issues: Discussion and Findings

A. Air Pollution

Background

Each stage of unconventional gas development has the potential to emit pollutants into the air. The sources include road dust; on-road and off-road vehicle activity; off-road diesel-fueled equipment that powers the drill rig, supplies the pressure for hydraulic fracturing, and generates electricity; gas escaping during drilling; volatilization of organic compounds from drilling fluids, muds, cuttings and flowback; releases of proppant, leakage and venting during flowback; flaring; methane leakage from valves, seals, and gaskets; compressor engine exhaust; and pneumatic pumps and devices.

The pollutants emitted can be classed as:

Hazardous air pollutants (HAPs). Also known as toxic air pollutants, these substances are known or suspected to cause cancer or other serious health effects, such as birth defects or reproductive effects. The Clean Air Act currently lists 188 toxic air pollutants to be regulated by EPA. They are emitted from all types of sources, including motor vehicles and stationary sources, such as manufacturing plants. EPA regulates HAPs by setting performance standards for major industrial sources based on what the air pollution control technology can achieve.

Volatile organic compounds (VOCs). This class includes a variety of chemicals that have high vapor pressure and are emitted as gases from some solids or liquids. Some have short- and long-term adverse health effects. Many VOCs are human-made chemicals that are used and produced in the manufacture of paints, pharmaceuticals, and refrigerants. VOCs are often components of petroleum fuels, hydraulic fluids, paint thinners, and dry cleaning agents. VOCs are common ground-water contaminants. Concentrations of VOCs are consistently higher indoors than outdoors, regardless of whether the homes are in rural areas or highly industrialized areas, possibly because so many household and office products contain VOCs.

Criteria pollutants. Ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide, and lead are called “criteria pollutants” because EPA sets the permissible levels in outside air on human health-based or environmentally-based criteria. The permissible levels are called National Ambient Air Quality Standards (NAAQS). Primary NAAQS are set to protect human health and secondary NAAQS are set to prevent environmental and property damage. A geographic area with air quality that is cleaner than the primary standard is called an "attainment" area; areas that do not meet the primary standard are called "nonattainment" areas.

Greenhouse gases. These are gases which allow direct sunlight (relative shortwave energy) to reach the Earth's surface unimpeded. As the shortwave energy (that in the visible and ultraviolet portion of the spectra) heats the surface, longer-wave (infrared) energy (heat) is reradiated to the atmosphere. Greenhouse gases absorb this energy, thereby allowing less heat to escape back to space, and 'trapping' it in the lower atmosphere. Many greenhouse gases occur naturally in the atmosphere, such as carbon dioxide, methane, water vapor, and nitrous oxide, while others are synthetic. NOAA, National Climate Data Center, www.ncdc.noaa.gov/monitoring-references/faq/greenhouse-gases.phpH.

Silica. Silica is a compound made up of silicon and oxygen atoms. The chemical formula is SiO_2. Silica exists in two states: crystalline and noncrystalline (also called amorphous). There is no specific federal ambient air quality standard for silica; it is addressed by the NAAQS for particulate matter. The controls for PM are the same controls for crystalline silica. This means that for those crystalline silica sources where PM is controlled, crystalline silica emissions are also reduced.

Ozone precursors. VOCs and nitrogen dioxide can combine in the presence of sunlight to produce ground level ozone.

Data and Discussion

Leidos, Inc., (2014) under contract with MDE, compiled a review of air monitoring activities and special studies that characterized ambient air quality impacts relevant to Marcellus Shale gas extraction and production activities. The studies differed in which pollutants were measured, and sometimes failed to identify what oil or gas activities were occurring at the time of measurement or the distance between the operations and the monitoring sites.

Leidos summarized completed and ongoing sampling efforts for criteria pollutants, hazardous air pollutants, and other metrics with regard to ambient monitoring off of well pads and outside fence lines in a table, which appears here in modified form.

Study Area (Reference)	Shale Play	Emissions Sources	Sampling Period
Star Shell Road (DRI 2011)	Barnett	Well pad with two condensate tanks in production phase	April 16-May 13, 2010
Shale Creek (DRI 2011)	Barnett	Compressor station	April 20-May 13, 2010
Arkansas (AR 2011)	Fayetteville	Six drilling sites, three hydraulic fracturing sites, and four compressor stations	November 2010 – June 2011 (measurement periods only a few hours at each site)
Barnett Shale Gas Impacts (Bunch 2014)	Barnett	All operations in both dry gas and rich gas areas	Focus on 2011
Mobile Measurement in Barnett Shale (Raghavendra *et al*. 2013)	Barnett	401 wet gas production lease sites, including wells, liquid storage tanks, and associated equipment (500-2,000 feet)	March-July 2012
Methane fluxes from Barnett Shale (Lauvaux *et al*. 2013)	Barnett	Regional air quality downwind of Fort Worth	March 2013
Natural Gas Exploration in Barnett Shale (Rich 2011 and Rich *et al*. 2013)	Barnett	39 sites (28 of which were within 2000 feet of at least one well, tank, compressor or separator), fifty 24-hour canister samples	2008-2010
Pennsylvania Long-Term Study (PA DEP, 2013c)	Marcellus	Three sites: Fractionation plant, compressor station, and in a populated area downwind of a booster station and ten wells	One year in 2012-2013

Study Area (Reference)	Shale Play	Emissions Sources	Sampling Period
Southwest Pennsylvania Short-Term Study (PA DEP 2010)	Marcellus	Two compressor stations, condensate tank farm, wastewater impoundment, and background site	Five events in 2010, each one week long
Northeast Pennsylvania Short-Term Study (PA DEP 2011)	Marcellus	Hydraulic fracturing, producing well pad, two compressor stations, and background site	Five events in 2010, each one week long
Northcentral Pennsylvania Short-Term Study (PA DEP 2011)	Marcellus	Two compressor stations, flaring well site, and active well-drilling site (background site from NE PA study)	Four events in 2010, each one week long
WVU study of drilling and construction (McCawley 2013)	Marcellus	Six sites: site preparation, vertical and horizontal drilling, hydraulic fracturing, and flowback	July 20-November 6, 2012 (longest sampling period at one site 28 days)
PA Community Survey (Steinzor 2013)	Marcellus	Residential areas near wells	34 canister samples (24-hour)
Fracturing in Greene County, PA (Pekney 2013)	Marcellus	Hydraulic fracturing over six wells	Fourteen weeks in 2012
Impacts on Pittsburgh Regional Air Quality (Swarthout *et al*. 2012 and Mitchell 2012)	Marcellus	Regional air quality around 8500-km^2 area centered on Pittsburgh	June 16-18, 2012

Table 1. Sampling efforts.
Source: Table 4 of Leidos 2014

Leidos focused on data collected in recent years because both the monitoring technology and equipment and practices in the industry have improved. It noted that the Marcellus Shale in Maryland is likely to contain dry gas, like much of the Barnett Shale. On the other hand, western Maryland's meteorological patterns are expected to be more similar to the other Marcellus Shale areas.

In reviewing a report by Bunch (2014) of community-oriented concentrations of benzene, n-hexane, toluene and xylenes from both wet gas and dry gas areas of the Barnett Shale by one hour and 24 hour samples, Leidos noted, that the median measured concentrations were below the chronic health effects levels for those chemicals by two orders of magnitude (100 times) or more. Wet gas and dry gas had similar values for benzene, ethylbenzene, toluene and xylenes, but n-hexane concentrations were slightly higher in the wet gas fields. The hourly measurements varied more than the 24-hour samples. The health report by Maryland Institute of Applied Environmental Health (MIAEH)(2014) did not discuss the Bunch report.

Leidos discusses a report by Raghavendra et al. (2013) of a survey of 401 lease sites (4,788 wells) across four counties in the Barnett Shale region for methane and hydrogen sulfide. Hydrogen sulfide exceeded the odor recognition threshold beyond the fence line at 5.5 percent of the lease sites. Methane concentrations exceeded 3 ppm at 14.4 percent of the lease sites. MIAEH (2014) did not discuss the report by Raghavendra et al.

McKenzie et al. (2012) published a report on ambient air monitoring in Garfield County, Colorado, *Human health risk assessment of air emissions from development of unconventional natural gas resources,* which was based on samples collected and analyzed by others. The Garfield County Department of Public Health collected the following samples:

- 163 ambient air samples from a fixed monitoring station located among rural home sites, ranches, and well pads, during both well development and production.
- 16 ambient air samples at each cardinal direction along 4 well pad perimeters while at least one well was in the process of collecting flowback into collections tanks vented directly to the air (i.e., uncontrolled emissions). The sampling points were 130 feet to 500 feet from the well pad center. The samples were taken over a 24 to 27-hour interval, during which diesel engines were also running, presumably contributing to the sample.
- Background samples 0.33 miles to 1 mile from each of the 4 well pads

In addition, a natural gas operator contracted a consultant to collect eight 24-hour samples at each cardinal direction at 350 feet and 500 feet from the well pad center during well completion activities at one well pad. According to McKenzie et al. (2012), "Of the 12 wells on this pad, 8 were producing salable natural gas; 1 had been drilled but not completed; 2 were being hydraulically fractured during daytime hours, with ensuing uncontrolled flowback during nighttime hours; and 1 was on uncontrolled flowback during nighttime hours" (p. 3).

MIAEH noted that "Results showed that concentrations of VOCs were significantly higher within 0.5 miles from the well pad (median benzene 2.6 µg/m3, range 0.9-69 µg/m3) compared to >0.5 miles from well pads (median benzene 0.9 µg/m3, range 0.1-14 µg/m3). The corresponding values for hexane were 7.7 µg/m3 (range 1.7-255 µg/m3 and 4.0 µg/m3 (range 0.23-62 µg/m3)" (p. 29). Leidos (2014) reports the maximum concentrations at the sampling points within 500 feet of the well pad center and noted that the differences between those values and measured concentrations at the fixed station "illustrate how significantly the distance from the well pad can influence the measurements." Leidos noted that "The measured concentrations of the 23 detected species [chemicals] at the fixed station were all below levels where chronic health effects might be expected. "

Making certain assumptions about exposure, and using the data described above, McKenzie et al. (2012) calculated the Hazard Quotient[2] for residents less than or equal to ½ mile of well sites and residents living greater than ½ mile from well sites. The chronic hazard quotient is related to an exposure lasting for years, but less than a lifetime. The subchronic hazard quotient is related to shorter term exposures. The specific exposure assumptions used by McKenzie et al. are included in Table 2. Hazard quotients calculated by McKenzie et al. reflect the development expected in Garfield County, Colorado, which is significantly more intense than what is predicted for Western Maryland.

[2] Hazard quotient is "the ratio of the potential exposure to the substance and the level at which no adverse effects are expected. If the Hazard Quotient is calculated to be less than 1, then no adverse health effects are expected as a result of exposure. If the Hazard Quotient is greater than 1, then adverse health effects are possible. The Hazard Quotient cannot be translated to a probability that adverse health effects will occur, and is unlikely to be proportional to risk. It is especially important to note that a Hazard Quotient exceeding 1 does not necessarily mean that adverse effects will occur." EPA, Technology Transfer Network, National Air Toxics Assessment, Glossary www.epa.gov/ttnatw01/nata/gloss.html (last accessed Nov. 18, 2014).

	Residents ≤1/2 mile	Residents >1/2 mile	Assumptions about exposure levels
Total chronic hazard quotient (Based on 95% Upper Confidence Limit of mean concentration)	1	0.4	20 month exposure to well completions on two well pads with 20 pads per well, followed by 340 months of gas production from these wells
Total subchronic hazard quotient (Based on 95% Upper Confidence Limit of mean concentration)	5	0.2	20 month exposure to well completions on two well pads with 20 pads per well

Table 2. Hazard quotients calculated by McKenzie et al.

The exposure of residents > ½ mile from well pads was related to the concentrations of the 163 area samples; while the exposure of residents ≤ ½ mile was based on the 24 well completion samples. Cumulative cancer risks were calculated to be 10 in a million for residents living within ½ mile and 6 in a million for residents living more than ½ mile of wells.[3] These risks could also be expressed as 1 in 100,000 (1 in 10^{-5}) and 0.6 in 100,000 (0.6 in 10^{-5}). While this is not an official EPA definition, the EPA Office of Solid Waste and Emergency Response, when communicating with the public about Superfund sites, defines an acceptable exposure level or acceptable risk as follows: "An 'acceptable' risk level (or range) of a contaminant, defined by law, that EPA uses to make cleanup decisions at Superfund sites. This is a risk level (or range) that people can be exposed to, including sensitive populations, without health problems. For carcinogens, the acceptable risk range is between 10^{-4} (1 in 10,000) and 10^{-6} (1 in 1,000,000)."[4] The cumulative cancer risks calculated by McKenzie et al. fall within this range of acceptable risk.

Colborn et al. (2014) reported results of weekly sampling beginning November 2, 2010 through October 11, 2011, at a fixed monitoring site that was within 1 mile of 130 producing natural gas wells in Garfield Colorado. The author reports that during the sampling period drilling and fracturing events occurred on three different pads. The author identifies "the vertical well pad of interest" as containing 16 wells drilled into Williams Fork Formation of the Mesa Verde Group at a total depth of approximately 8,300 feet (2530 km) in tight sands. The USGS (2003) reports that gas production in this formation is primarily from fluvial channel sandstone reservoirs. The Williams Fork Formation contains coal deposits that are thought to be the source for most of the gas. Leidos (2014) notes the distinction between this formation and the Marcellus Shale.

According to Colborn et al., "Means, ranges, and standard deviations were presented for all chemicals detected at least once. … Because of the exploratory nature of the study and the relatively small data

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[3] "A risk level of 'N' in a million implies a likelihood that up to 'N' people, out of one million equally exposed people would contract cancer if exposed continuously (24 hours per day) to the specific concentration over 70 years (an assumed lifetime). This would be in addition to those cancer cases that would normally occur in an unexposed population of one million people. " EPA, Technology Transfer Network, National Air Toxics Assessment, Glossary www.epa.gov/ttnatw01/nata/gloss.html (last accessed Nov. 18, 2014)

[4] EPA, Risk Communication, Attachment 6, Useful Terms and Definitions for Communicating Risk, www.epa.gov/superfund/community/pdfs/toolkit/risk_communication-attachment6.pdf

set, values for non-detects were not imputed, no data transformations were performed, and statistical tests of significance were not conducted." MIAEH noted that Colborn "reported the highest levels of non-methane hydrocarbons (NMHC) concentrations during the initial drilling phase. The methane concentrations reported were particularly high ranging from 1600 to 5500 ppb (mean 2473 ppb), while methylene chloride ranged from 2.7 to 1730 ppb (mean 206 ppb). The authors reported that the levels of PAHs [polycyclic aromatic hydrocarbons] detected in this particular study were higher than the ones that produced lower developmental and IQ scores in children in a separate study" (p. 29). Leidos (2014) noted that Colborn attributed the high methylene chloride levels to the use of that substance as a cleaning solvent on the pad and that elevated levels of methylene chloride were not found in two Pennsylvania studies.

A report prepared for the West Virginia Department of Environmental Protection by McCawley (2013) discussed data collected at seven drilling sites to determine the effectiveness of a 625 foot setback from the center of a well pad. The pads were located in Brooke, Marion, and Wetzel Counties, West Virginia, in areas where there the gas contains natural gas liquids. The study was designed to measure ambient concentrations during pad site development, vertical drilling, horizontal drilling, hydraulic fracturing, and flowback and completion. No information was available on what air pollution controls, if any, were being used.

Detectable levels of dust and volatile organic compounds were found at 625 feet. Measured levels of hydrocarbons were compared to the chronic Minimum Risk Level (MRL) below which no health effects should occur if exposure at that level were to continue for a year or more. The measured exposure level divided by the MRL is called the Hazard Quotient (HQ); if the measured value exceeds the MRL, that number will be greater than 1.0. The author explained that "An exposure level exceeding the MRL merely indicates that further evaluation of the exposure scenario and potentially exposed population may be warranted, although the more often the MRL is exceeded and the greater the magnitude of the value by which the MRL is exceeded, the greater the likelihood that an adverse health outcome will occur" (p. 8).

One or all of the BTEX compounds (benzene, toluene, ethylbenzene and xylenes) were found at all drill sites. Benzene concentrations greater than the MRL were measured at four of the seven sites; the HQs varied from 1.3 to 28.3. Except for benzene, the HQ was 1.0 or less for all the measured hydrocarbons. MIAEH (2014) observed that the concentrations of selected VOCs in West Virginia study varied considerably and were higher than the McKenzie (2012) study in Colorado.

No data have been found on ambient levels of silica in communities near well pads where sand is used as a proppant. The activities of transporting, moving, and refilling silica sand into and through sand movers, along transfer belts, and into blender hoppers at the well site can release dusts containing silica into the air. Recent work by the National Institute for Occupational Safety and Health (NIOSH) found that some oil and gas workers are exposed to crystalline silica far in excess of permissible exposure levels set by the Occupational Safety and Health Administration (OSHA). The federal agency issued a Hazard Alert that recommended steps for reducing the amount of silica that is emitted into the air. (OSHA 2012).

MIAEH (2014) also estimated yearly process-level emissions of particulate matter, NOx, and VOCs for two drilling scenarios using a variety of assumptions. One of the assumptions was that there would be no significant reductions in the emission rates from these processes after 2009, despite the fact that two significant federal regulations were promulgated after 2009 that require reduced emission completions and emission controls on large storage tanks. MIAEH calculated that during the peak production year of the more aggressive drilling scenario, approximately 22 tons of fine particulate matter, 468 tons of NOx, and 517 tons of VOCs would be emitted by all the unconventional natural gas development and production-related activities in Garrett and Allegany Counties together. Roy et al. (2014) estimated that process level emission rates related to drill rigs, hydraulic fracturing and truck traffic would decline between 2009 and 2020 by 54 percent for NOx, 58 percent for fine particulate matter, and 62 percent for VOCs.

MIAEH concluded that there is a high likelihood that changes in air quality related to unconventional gas development will have a negative impact on public health in Garrett and Allegany Counties. This conclusion was qualified, as were all MIAEH's risk rankings: "Our assessments of potential health impacts are not predictions that these effects will necessarily occur in Maryland, where regulation is likely to be stricter than in some states where UNGDP is already underway. Rather, we provide assessments of the impacts that could occur and that need to be addressed by preventive public health measures if and when drilling is allowed" (p. xv).

In their Interim Final Best Practices Report (MDE and DNR, 2014a), the Departments identified requirements that will reduce air pollution from Marcellus Shale gas development. Among these are Reduced Emissions Completions (REC), limitations on flaring, use of ultra-low sulfur diesel fuel, limitations on engine idling, and most importantly, top-down Best Available Technology (BAT) for the control of air emissions. Top-down BAT means that the applicant will be required to consider all available technology and implement BAT control technologies unless it can demonstrate that those control technologies are not feasible, are cost-prohibitive or will not meaningfully reduce emissions from that component or piece of equipment. While the amount of emission reduction for some control technologies have not been established, in field measurements by Allen et al. (2013) REC was shown to reduce methane emissions by 98 percent (compared to potential emissions). In its Background Supplemental Technical Support Document for the Final New Source Performance Standards, (EPA, 2012). EPA estimated that REC could reduce the amount of VOCs released during hydraulic gas well completion by 95 percent.

The Departments' risk assessment (MDE and DNR, 2014b) ranked the risks posed by air pollution as low or moderate, except for:

1. A high ranking (high probability, moderate consequence) for NOx, benzene and particulate matter from fuel-burning pumps during hydraulic fracturing/well completion (more intensive drilling scenario only);
2. A high ranking (high probability, moderate consequence) for methane, H_2S, VOCs, natural gas liquids and BTEX from flowback storage tanks in the hydraulic fracturing/well completion phase (more intensive drilling scenario only);

3. Insufficient data to evaluate the risk of NOx, benzene, and dust/particulate matter from truck trips during the drilling phase
4. Insufficient data to evaluate the risk of NOx, benzene, and particulate matter from combustion during the hydraulic fracturing stage;
5. Insufficient data to evaluate the risk of dust/particulate matter from noncombustion sources during the hydraulic fracturing stage (more intensive drilling scenario only); and
6. Insufficient data to evaluate the risk for NOx, benzene, and particulate matter from fuel burning compressors during the production stage.

The hydraulic fracturing stage is of relatively short duration – approximately 5 days per well. During this time, the pumps would be used to pressurize the fracing fluid. Under the more intensive drilling scenario, this activity could occur for an average of 225 days per year over the 10-year drilling period; however, it is likely to occur for approximately 30 days for any six-well pad.

The high ranking for methane, H_2S, VOCs, natural gas liquids and BTEX from flowback storage tanks is probably overly conservative because the Marcellus Shale gas in Maryland is expected to be dry. In addition flowback must be placed in covered tanks and vented to a flare or other pollution reduction device.

Conclusion

Air pollution from operations at the pad and from traffic is a concern. Implementation of the best practices, especially top-down BAT and the storage of flowback in tanks with emission controls instead of impoundments, should significantly reduce ambient levels of pollutants emanating from the pad area. If monitoring does not confirm the effectiveness of these measures, additional controls may be necessary.

Air emissions from vehicles are also a concern. If alternative means for moving water and wastes are available, they should be investigated and required if appropriate. The Comprehensive Gas Development Plan should identify routes that do not require heavy truck traffic on roads that are close to homes and schools. Inspection of trucks for compliance with Maryland's Diesel Emissions Control Program should be scheduled to coincide with expected heavy truck traffic.

B. Methane Migration

Background

Methane, the primary component of natural gas, is an odorless[5], colorless gas with the chemical formula CH_4. Methane in its gaseous form is a simple asphyxiant, which in high concentrations may displace the oxygen supply needed for breathing, especially in confined spaces. Decreased oxygen can cause suffocation and loss of consciousness. It can also cause headache, dizziness, weakness, nausea, vomiting, and loss of coordination (National Institutes of Health (NIH). NIH Tox Town - Methane. http://toxtown.nlm.nih.gov/text_version/chemicals.php?id=92). Similar ecological concerns are applicable to organisms inhabiting caves or other confined habitats where gaseous methane concentrations may increase.

[5] An odorant is added to natural gas before it enters the distribution system so leaks can be easily detected.

Methane present in drinking water does not affect taste or appearance, except that it can cause the water to appear cloudy or produce effervescent gas bubbles. There is no evidence that ingestion of methane in drinking water affects human health. (NIOSH).

Methane is extremely flammable and can form an explosive mixture with air at concentrations between 5 percent (lower explosive limit) and 15 percent (upper explosive limit). If methane enters a building, either through contaminated drinking water or from other pathways, the concentration can build up in the indoor air, creating a risk of fire or explosion and, in an extreme case, asphyxiation. The US Department of the Interior, Office of Surface Mining, suggests that when the level of methane gas in the water is less than 10 mg/L it is safe, but monitoring is required at 10 to 28 mg/L, and immediate action is needed above 28 mg/L. (Eltschlager, 2001).

Methane is a powerful greenhouse gas. This is further discussed in another section of this report.

Gas wells are designed and constructed to carry the natural gas from the target formation to the surface for sale and to isolate all the zones through which the well passes from each other and from the gas well. The design includes concentric steel casing of decreasing diameter and cement to fill the spaces between the concentric steel casings and between the outermost casing and the rock through which the vertical borehole was drilled. If the well casing leaks, methane can escape from inside the well and, because methane is buoyant, rise through the subsurface to the shallow groundwater or to the atmosphere. In addition, if there are imperfections in the cement, gas from outside the gas well, for example, from shallower, intermediate methane-bearing formations, can migrate through the imperfections in the cement and upward. In either case, drinking water aquifers could be contaminated by methane.

Data and Discussion

Studies have documented that some drinking water wells have been contaminated with gas from deep reservoir rocks, including the Marcellus Shale. In contrast, a study in the Fayetteville Shale in Arkansas found no methane contamination of groundwater (Kresse, 2012). In northeastern Pennsylvania, some shallow wells were contaminated with Marcellus gas; the wells within 1 km of drilling sites were more likely to be contaminated (Osborn, 2011; Jackson, 2013). It has been suggested that the likelihood of stray methane contamination depends on both well integrity and local geology that may or may not provide flow paths (Warner et al., 2013). Methane can enter groundwater in the absence of gas development activities; sources of methane in groundwater include coal deposits and biological activity in shallow buried sediments that contain organic material. There is consensus among most geologists that, if there is a separation of at least 2,000 vertical feet between the target formation (the Marcellus Shale, for example) and the drinking water aquifers (which generally occur at shallow depths) the induced fracture cannot extend far enough to reach the drinking water aquifers. There are two ways methane from the Marcellus Shale could enter drinking water aquifers: if the fractures induced by hydraulic fracturing intersect a natural fracture or an improperly abandoned old gas well that provides a pathway to drinking water aquifers, or if methane moves outside the Marcellus Shale well along the vertical borehole because of casing or cement failure.

A minimum separation of 2,000 vertical feet between the top of the target formation and the lowest drinking water aquifer will be required. As also indicated in the Interim Final Best Practices (MDE and DNR, 2014a), the State will require that a prospective applicant for a well permit first secure MDE's approval of a Comprehensive Gas Development Plan, which must include a geological investigation by the applicant of the area covered by the CGDP. The geological survey will investigate the location of all gas wells (abandoned and existing), current water supply wells and springs, fracture-trace mapping, orientation and location of all joints and fractures and other additional geologic information as required by the State. Using this information, the gas wells can be located to avoid proximity to existing fractures and other gas wells.

The Interim Final Best Practices Report recommended measures to assure good quality casing and cement and testing methods to detect possible loss of integrity. Before commencing hydraulic fracturing, the permittee must certify the sufficiency of the zonal isolation to MDE with supporting data in the form of well logs, pressure test results, and other appropriate data.

The Departments had initially recommended a 1,000 foot setback from private residential drinking water wells but, in response to comments on the draft report, changed the recommendation to require a 2,000 foot setback from the edge of the drill pad to a private drinking water well, with a possibility of a waiver to locate between 1,000 and 2,000 feet if the proposed gas well pad is not upgradient of the private drinking water well and the water well owner consents. The reasons for the change related to surface spills, not stray methane. The Departments recognize that, because gaseous methane is buoyant and may move through fissures in the ground, this variance is not appropriate to protect against stray methane. The Departments now recommend a setback of 2,000 feet from the edge of the drill pad to a private drinking water well, without an option for a variance. In light of the other best practices, the Departments do not think a setback of one km is necessary.

If a drinking water well is contaminated with methane, there are methods for removing the methane from the well water by venting the well or aerating the water. If the cause of the elevated methane is corrected, methane levels in the drinking water may return to normal.

Conclusion

There is no single practice that will eliminate the risk of methane migration; rather, the Departments are proposing a combination of setbacks, appropriate best practices, integrity testing, rigorous monitoring/inspections/enforcement, timely identification and correction of problems and mitigation if methane contamination should occur.

C. Noise[6]

Background

It is known that a person's well-being can be affected by noise through loss of sleep, speech interference, hearing impairment, and a variety of other psychological and physiological factors. The equipment used at well pads during drilling and hydraulic fracturing can be very noisy.

[6] Noise associated with traffic is addressed in Section J, below.

Data and Discussion

The scale for measuring noise intensity is the decibel scale, with a weighted scale (dBA) to account for relative loudness as perceived by the human ear. The noise scale is logarithmic, and an increase of 10 decibels represents a sound that is 10 times louder; however, humans do not perceive sound this way. A change of 3 decibels is at the threshold of what a person can detect; a 5 decibel change is readily noticeable; and the human ear perceives an increase of 10 dBA as a doubling of noise levels. (NYSDEC, 2011).

EPA has identified 55 decibels outdoors and 45 decibels indoors as noise levels that will not interfere with normal activities or cause annoyance (EPA, 1978). These levels of noise permit spoken conversation and other activities such as sleeping, working and recreation. Natural nighttime environmental noise levels in rural areas are commonly estimated to be as low as 30 dBA, depending on weather conditions and natural noise levels. The World Health Organization recommends that sound levels should not exceed 30 dBA indoors for continuous noise and 45 dBA for intermittent noise. (WHO, 2000).

The combination of noises is not perceived as the sum of the noises. EPA explained the phenomenon this way: "For example, if a sound of 70 dB is added to another sound of 70 dB, the total is only a 3-decible increase (to 73 dB), not a doubling to 140 dB. Furthermore, if two sounds are of different levels, the lower level adds less to the higher level. In other words, adding a 60 decibel sound to a 70 decibel sound only increases the total sound pressure level less than one-half decibel" (EPA, 1978, p. 3).

The contribution of outdoor noise to indoor noise depends on several factors, including the construction of the building and whether the windows are opened or closed. Generally dwellings are categorized as those built in warm climates and those built in cold climates. EPA reports the following (EPA, 1978, p.11):

Typical Sound Level Reductions of Buildings		
	Windows Opened	Windows Closed
Warm Climate	12 dB	24 dB
Cold Climate	17 dB	27 dB
Approximate National Average	15 dB	26 dB

Table 3. Typical Sound Reductions.

EPA notes that indoor levels are often comparable to or higher than levels measured outdoors. Internal noise sources such as appliances, radio and television, heating and ventilating equipment contribute to indoor noise (EPA, 1978).

Noise drops with distance. By application of the inverse square law and the logarithmic decibel scale, it can be demonstrated that a sound level drops 6 dBA for each doubling of distance from the source. (NYSDEC, 2011)

The Department of the Environment has promulgated standards for environmental noise; they can be found in the Code of Maryland Regulations (COMAR) 26.02.03. The standards are goals expressed in terms of equivalent A-weighted sound levels which are protective of the public health and welfare. With certain exceptions, a person may not cause or permit noise levels which exceed those specified in Table 4.

Maximum Allowable Noise Levels (dBA) for Receiving Land Use Categories			
Day/Night	Industrial	Commercial	Residential
Day (7 AM to 10 PM)	75	67	65
Night (10 PM to 7 AM)	75	62	55

Table 4. Maryland Maximum Allowable Noise Levels

The regulations permit more noise for construction and demolition site activities: 90 dBA during the daytime hours, and the levels in Table 4, above, during nighttime hours. In addition, a person may not cause a prominent discrete tone[7] or periodic noise[8] which exceeds a level which is 5 dBA lower than the applicable level listed in the table. These noise standards do not apply to on-road vehicles. The noise regulations also address vibrations: “A person may not cause or permit, beyond the property line of a source, vibration of sufficient intensity to cause another person to be aware of the vibration by such direct means as sensation of touch or visual observation of moving objects. The observer shall be located at or within the property line of the receiving property when vibration determinations are made.”

Information on the noise expected to be produced by the activities used in each phase of horizontal drilling and HVHF, and the evaluation of the noise at various distances from the source, are shown in Table 5.

Phase	dBA at a Distance of (Feet)					
	50	**250**	**500**	**1,000**	**1,500**	**2,000**
Construction of access road	89	75	69	63	59	57
Well pad preparation	84	70	64	58	55	52
Rotary Air Drilling	79	64	58	52	48	45
Horizontal Drilling	76	62	56	50	47	44
HVHF (20 Pumper trucks operating at a sound level of 115 dBA)	104	90	84	78	74	72

Table 5. Noise levels at distances

Source: Tables 6.54 through 6.58 (NYSDEC, 2011)

[7] "Prominent discrete tone" means any sound which can be distinctly heard as a single pitch or a set of single pitches. For the purposes of this regulation, a prominent discrete tone shall exist if the one-third octave band sound pressure level in the band with the tone exceeds the arithmetic average of the sound pressure levels of the 2 contiguous one-third octave bands by 5 dB for center frequencies of 500 Hz and above and by 8 dB for center frequencies between 160 and 400 Hz and by 15 dB for center frequencies less than or equal to 125 Hz. COMAR 26.03.02.01.

[8] "Periodic noise" means noise possessing a repetitive on-and-off characteristic with a rapid rise to maximum and a short decay not exceeding 2 seconds. Id.

Minimum setback distances from the edge of disturbance of the well pad are:

Setback from edge of drill pad disturbance to	Distance in Feet
The boundary of the property on which the well is drilled (unless necessary due to site constraints)	1,000
Any occupied building	1,000
Private drinking water well[9]	2,000
A church or a school	1,000

Table 6. Setbacks

The Maryland residential noise standard should be met at a distance of 1,000 feet from the drill pad during construction of the access road, preparation of the well pad, and operation of the drill rigs. During hydraulic fracturing, however, and perhaps during other phases when electricity is generated on-site, noise reduction will be necessary.

The Interim Final Best Practices Report (MDE and DNR, 2014a) identified practices that can reduce noise, but it did not require reductions below the levels necessary to meet Maryland's noise standards. The best practices provide that the applicant must submit a plan for complying with the noise standards and for verifying compliance after operations begin. If the applicant's plan for complying with the noise standards does not demonstrate that the noise standards will be met, the permit can mandate additional noise reduction measures. If compliance with the noise standards is not verified after operations begin, MDE could issue an administrative order requiring additional corrective action. Various noise reduction measures can be taken to reduce the noise generated by equipment, or acoustic barriers can be installed.

Conclusion

The best practices will ensure that noise levels will not exceed standards that are designed to prevent the disruption of human activities or cause annoyance to the average person. To reduce noise further, however, additional steps will be required. First, noise modeling should be required for every drill site to support and verify the permit applicant's plan for complying with noise standards. Commercially available software is capable of simulating the three-dimensional movement of sound, atmospheric and other noise absorption features, and attenuation due to topography. (NYSDEC, 2011). Second, noise reduction devices such as mufflers will be required for all equipment at the pad site.

D. Soil Contamination, Groundwater Contamination[10] and Surface Water Contamination

Background

Soil, groundwater and surface water could be contaminated by surface releases of fuel, additives, drilling mud, hydraulic fracturing fluid, flowback, produced water, or condensate. Some of the potential contaminants present health hazards if ingested or inhaled, or by dermal contact. It might be possible to remove contaminated soil or remediate it in place while public access is restricted, if necessary. Besides

[9] Because a private drinking water well is usually located close to the home it serves, this setback will increase the distance between the well pad and the home.

[10] Methane contamination is covered in Section B, above.

methane, shale gas development introduces the potential for groundwater contamination by other fluids such as drilling fluid, hydraulic fracturing fluid, flowback water and production water. Both flowback and production water tend to have very high salinities (Haluszczak et al., 2013), so in their analysis of potential risk pathways, Krupnick et al. (2013) refer to groundwater contamination with brine as "intrusion of saline formation water" (p. 20).

Contamination of an underground source of drinking water (USDW) with fracturing fluids or brine could render the USDW unusable and could also impact aquatic life if and where the groundwater discharges to surface water. Some chemicals that are human health hazards have been used in hydraulic fracturing; for example, methanol, ethylene glycol, diesel fuel, and naphthalene (Waxman, 2011). Flowback and formation waters typically contain elevated Cl, Br, Na, K, Ca, Mg, Sr, Ba, Ra, Fe, Mn, total dissolved solids, and naturally occurring radioactive material (NORM) (Haluszczak et al., 2013).

Groundwater, once it is contaminated, is difficult to remediate, although sometimes it is possible to pump and treat the water or use techniques like bioremediation to treat it in place. Public drinking water systems may be able to treat the raw water to remove contaminants before distributing it. Point-of-entry and point-of-use drinking water treatment systems can be installed in homes to remove some contaminants from the well water. Activated carbon filtration can effectively reduce the concentrations of certain organic contaminants, lead, dissolved radon, and other substances. Mechanical filters can remove particulate matter that contributes to turbidity. No one treatment system manages all contaminants equally well, and the systems must be properly maintained to be effective.

Vehicular accidents involving trucks transporting muds, chemical additives or wastes could result in the release of vehicle fluids (fuel, antifreeze, etc.) or the cargo if the tank trucks or containers are compromised or rupture. If materials are spilled at the pad and are not contained, they could run off and contaminate soil, groundwater and surface water. During early stages of drilling, before the surface casing is installed, the drill bit passes through drinking water aquifers. During this activity, there is a possibility that turbidity will increase in drinking water aquifers, as well as the possibility that drilling mud or other drilling aids will enter the drinking water aquifers. There is also the possibility of subsurface contamination by saline fluids such as fracturing fluids, flowback, and production water. These will be considered in turn.

Data and Discussion

<u>Surface spills</u>.

Vehicular accidents

If the contaminated soil is not removed, or if material is not cleaned up in a timely manner before it infiltrates into the ground or runs off to surface water, the spilled material could cause contamination of any of these media (soil, groundwater, and surface water). Transportation incidents involving hazardous materials are relatively rare; using data from the federal Pipeline and Hazardous Materials Safety Administration, Maryland's risk assessment calculated the probability that a single trip would result in an incident as 0.005 percent. (MDE and DNR, 2014b, p. 6). This is incidence data; not every incident results in a release to the environment. Applying this rate to shipments of chemicals used as drilling additives or fracturing additives leads to a prediction of fewer than 2 incidents involving additives in the course of delivering additives for all 450 wells over 10 years of the more intensive drilling scenario. Applying this incident rate to the number of truck trips to transport waste material off-site predicts approximately 8 incidents, but the actual number of trips is likely to be lower, because the risk assessment assumed that all flowback and produced water would be sent by truck for disposal. Best practices require that, unless the operator can demonstrate that it is impracticable to do so, at least 90 percent of the flowback and produced water must be recycled and reused on site. Waste shipments will be tracked to confirm that the entire amount was delivered to a proper treatment or disposal facility.

Releases at the well pad

The pad is the center of activity during drilling and high volume hydraulic fracturing. Not only are the drill rig and vertical borehole there, but the pad is also the site for storing fuel and chemicals, handling drilling mud and cuttings, mixing and pressurizing hydraulic fracturing fluid, mixing and pumping the cement, and handling flowback and produced water. Pollutants released on the pad could enter the environment by infiltrating through the pad, running off the pad, or being washed from the pad.

As far as we have been able to determine, a comprehensive study of the causes of spills has not been done; however, it appears that releases at the well pad occur in any of several ways: operator error, failure of valves, hoses or pipes, tank failures, blowouts, or incidents involving firefighting. In some reported cases, the spilled material was not contained on the pad or was washed from the pad by precipitation or by firefighters.

The best management practices address these possibilities as follows. No discharge of potentially contaminated stormwater or pollutants from the pad shall be allowed. Drill pads must be underlain with a synthetic liner with a maximum hydraulic conductivity of 10^{-7} centimeters per second and the liner must be protected by decking material. Spills on the pad must be cleaned up as soon as practicable and the waste material properly disposed of in accordance with law. The drill pad must be surrounded by an impermeable berm such that the pad can contain at least the volume of a 25 year, 24 hour storm[11]. The berm may be made impermeable by extension of the liner. Collected stormwater may be used for hydraulic fracturing, but prior to use, it must be stored in tanks and not in a pit or pond. In addition, the design must allow for the transfer of stormwater and other liquids that collect on the pad to storage tanks on the pad or to trucks that can safely transport the liquid for proper disposal. The collection of stormwater and other liquids may cease only when all potential pollutants have been removed from the pad and appropriate, approved stormwater management can be implemented. Tanks and containers must be surrounded with a continuous dike or wall capable of effectively holding the total volume of the largest storage container or tank located within the area enclosed by the dike or wall. The construction and composition of this emergency holding area shall prevent movement of any liquid from this area into the waters of the State.

[11] This is a more severe storm than the 10 year, 24 hour storm described in the Interim Final Best Practices Report. According to NOAA's National Weather Service, the 25 year, 24 hour storm in Oakland is 4.5 inches (90 % confidence 4.11 to 4.89);in Friendsville 4.32 (3.94 to 4.69); in Grantsville 4.59 (4.15 to 5.05); in Frostburg 4.54 (4.12 to 4.96); and in Cumberland 4.43 (4.06 to 4.78). National Weather Service, Hydrometeorological Design Studies Center Precipitation Frequency Data Center, http://hdsc.nws.noaa.gov/hdsc/pfds/.

A three acre pad capable of containing the 25 year, 24 hour precipitation event of 4.5 inches would have containment capacity of over 122,000 gallons. Few reported spills have been that large. During the processing of large volumes of material, there are workers at the site, so a significant spill would not go unnoticed. As an additional precaution, however, Maryland will require that at least two vacuum trucks should be on standby at the site during drilling, fracturing, and flowback so that any spills occurring during those stages, which could be of significant volume, could be promptly removed from the pad.

The probability of a well blowout is low as they rarely occur (approximately 1 well blowout per 1,000 wells). Implementation of the best practices, especially redundant blow out protection mechanisms and frequent testing, should further reduce the potential for a well blowout to occur. When a blowout occurs, material may be ejected high into the air and it may or may not fall directly on the pad. It is likely that the well pad could contain material that falls on it. Material that falls away from the pad would have to be cleaned up. Setbacks will reduce the chance that material that falls off the pad will impact surface water or ground water before spill cleanup and emergency response.

Spill Prevention, Control and Countermeasures Plans (SPCC Plans) are intended to prevent any discharge of oil and other hazardous substances. Spill cleanup and emergency response plans are intended to address spills or other releases after they occur. The Departments identify as a best practice that facilities develop plans for preventing the spills of oil and hazardous substances, using drip pans and secondary containment structures to contain spills, conducting periodic inspections, using signs and labels, having appropriate personal protective equipment and appropriate spill response equipment at the facility, training employees and contractors, and establishing a communications plan. In addition, the operator shall identify specially trained and equipped personnel who could respond to a well blowout, fire, or other incident that personnel at the site cannot manage. These specially trained and equipped personnel must be capable of arriving at the site within 24 hours of the incident.

Operators shall, prior to commencement of drilling, develop and implement an emergency response plan, establish a way of informing local water companies promptly in the event of spills or releases, and work with the governing body of the local jurisdiction in which the well is located to verify that local responders have appropriate equipment and training to respond to an emergency at a well. This should reduce the likelihood that inappropriate methods will be used that will result in washing the contaminants from the well pad.

Drilling through drinking water aquifers

Drinking water aquifers in Garrett and western Allegany Counties lie relatively near the surface; saline water aquifers are present at greater depth. Surface casing must be installed and cemented in the gas well to isolate the wellbore from the surrounding earth to a depth of at least 100 feet below the deepest fresh water aquifer. Until this barrier is installed, however, the drilling can cause increased turbidity in the aquifer that may show up in nearby wells. This can also occur when new drinking water wells are drilled, and usually subsides within a short time. The drilling mud is weighted to apply pressure and prevent fluids from entering the borehole. Some of the drilling mud may enter drinking water aquifers if the pressure is too great. For this reason, the best practices require that only additives suitable for drilling through potable water supplies can be used while drilling through freshwater aquifers.[12]

Contamination by other saline fluids

Contamination of a fresh water USDW by hydraulic fracturing fluid, saline formation flowback, formation water or methane should be impossible if surface casing is properly installed – with the casing set to an appropriate depth, and the casing and cement functioning properly. Adherence to the drilling, casing and cementing plan, as well as integrity testing will be a condition of the permit. Best practices will require that, before commencing hydraulic fracturing, the permittee must certify the sufficiency of the zonal isolation to MDE with supporting data in the form of well logs, pressure test results, and other appropriate data. The well is pressurized only during the hydraulic fracturing stage, and therefore releases of hydraulic fracturing fluid through casing or cement failure is unlikely.

Several authors report that they found no evidence of contamination of drinking water with brine (Osborn et al., 2011; Jackson et al., 2013). In a recent report investigating the mechanisms by which human activity could cause methane gas contamination to occur in drinking water wells, the authors noted that samples with higher levels of thermogenic gas did not also exhibit higher chloride levels, suggesting that the thermogenic hydrocarbon gas had separated from the brine and migrated in the gas phase. For other samples where gas and brine levels did correlate, they concluded that the presence of gas and chloride was natural and possibly a result of tectonically driven migration over geological time of gas-rich brine from an underlying source formation or gas-bearing formation of intermediate depth (Darrah et al., 2014). Because brine is so dense, it is not likely to migrate upward through casing/cementing failures without significant induced pressure. Many gas shales, including most of the Marcellus, are slightly to moderately overpressured, but once gas is produced, the formation pressure drops rapidly to hydrostatic and below, and the preferred flow direction of gas and formation brines is along the pressure gradient toward the wellbore (Personal Communication, Daniel Soeder, U.S. Department of Energy, National Energy Technology Laboratory, November 5, 2014). Once gas is being produced, there is nothing to drive fluids along other paths to the surface.

Conclusion

The likelihood of a transportation-related incident that will result in the release of significant amounts of hazardous materials is low. If a spill occurs because of a transportation-related incident but is cleaned up in accordance with law, the risk to groundwater is low, and the risk to surface water is low unless the spill flows directly into surface water. If a spill occurs directly into surface water upstream of a public drinking water intake, there could be an interruption to providing safe drinking water to the public.

The likelihood of soil, groundwater or surface water contamination from releases at the well site is low because of the requirement that the pad be able to contain a very large volume and the implementation of a spill prevention and response plan. Similarly, the risk of contamination of a drinking water aquifer by hazardous materials during drilling or because of faulty casing and cement is low.

[12] This practice will be clarified to provide that only substances compliant with SNF/ANSI Standard 60 can be used.

E. NORM and TENORM

Background

Much of the petroleum in the earth's crust was created at the site of ancients seas by the decay of sea life. As a result, oil and gas often occur in rock formations that contain brine (salt water). Radionuclides, along with other minerals, are dissolved in the brine. The Marcellus Shale formed about 390 million years ago from sediment and organic matter that settled in a shallow sea. The shale, like virtually all environmental media, contains radioactive elements, including uranium and thorium. A concise explanation was provided in a USGS paper from 2013:

> Radium (Ra) is a naturally occurring radioactive material (NORM) that is present as a component of the Marcellus Shale and is produced from the radioactive decay of high concentrations of uranium and thorium found naturally within black shales. Uranium is poorly soluble in water under the anoxic (oxygen-poor) conditions typical of black shales, but radium is readily dissolved and transported. Although two of the radium isotopes (223Ra and 224Ra) have short half-lives (a few days), the other two isotopes, 226Ra and 228Ra, have 1,622 and 5.75 year half-lives, respectively; if dispersed in the environment, these isotopes will persist for long periods of time. Chemically, radium behaves similarly to calcium (Ca), strontium (Sr), and barium (Ba). Radium can readily precipitate along with salts of Ca, Sr, and Ba in groundwater or produced brines having high total dissolved solids to form scale in or on drilling equipment or in on-site storage tanks or brine pits.[13] The scale precipitate is rich in radium, and that may emit radiation to those working near such equipment over time. The scale may eventually be removed from the pipe and then is added to the waste stream from drilling that must go to a landfill or can be dispersed to the local soil. Leachates from these materials may contain radium that may eventually reach the local water table or run off to the local watershed.
>
> The concentrations of NORM present in black shale drill cuttings, drilling mud, scale and sludge build-ups, fluids from spills, treatment residuals, and other waste products may be greater than background environmental levels. Disposal of these waste products on-site or in landfill burial sites will require assessments of both gamma radiation emissions and radionuclide concentrations in solids and liquids. Dispersal of radium into soils may have several effects in addition to the potential increase in gamma radiation exposures and the potential for leaching into water resources. The 226Ra emits radon gas as a decay product; structures built on the soil that contains 226Ra-bearing waste may have high levels of indoor-air radon that require monitoring due to this type of exposure. Plants may also take up the 226Ra from soil. Recently (2013), the Commonwealth of Pennsylvania has initiated a study of the radioactivity of the Marcellus Shale through all aspects of the gas drilling, extraction, and waste disposal. (Citations and a reference to a figure omitted.)

[13] This concentrated material is referred to as technologically enhance naturally occurring radioactive material.

EPA describes the risks of radium as follows (EPA, Radiation Protection, Radium http://www.epa.gov/radiation/radionuclides/radium.html#properties:

> Radium emits several different kinds of radiation, in particular, alpha[14] and gamma[15] radiation. Alpha radiation is only a concern if radium is taken into the body through inhalation or ingestion. Gamma radiation, or rays, can expose individual even at a distance. As a result, radium on the ground, for example, can expose individuals externally to gamma rays or be inhaled or ingested with contaminated food or water. The greatest health risk from radium in the environment, however, is actually its decay product radon, which can collect in buildings.
>
> Most radium that is swallowed (about 80%) promptly leaves the body through the feces. The other 20% enters the bloodstream and accumulates preferentially in the bones. Some of this radium is excreted through the feces and urine over a long time. However, a portion will remain in the bones throughout the person's lifetime.
>
> Long-term exposure to radium increases the risk of developing several diseases. Inhaled or ingested radium increases the risk of developing such diseases as lymphoma, bone cancer, and diseases that affect the formation of blood, such as leukemia and aplastic anemia. These effects usually take years to develop. External exposure to radium's gamma radiation increases the risk of cancer to varying degrees in all tissues and organs.

Radon is an odorless, colorless radioactive gas. Radon can exist in different isotopic forms (having different numbers of neutrons in the nucleus). Radon decays rapidly; its most stable isotope is Radon-222, which has a half-life of 3.8 days; that is, half its radioactive atoms will decay every 3.8 days. As radon itself decays, it produces new radioactive daughter products. Unlike the gaseous radon itself, radon’s daughter products bond with other elements in solids or may be dissolved in solutions. Radon and its daughters present a risk of lung cancer.

Radioactive materials must be managed properly so that persons are not exposed to unsafe levels of radioactivity. The management must address the materials from the time they are generated to the time they are properly disposed of.

Data and Discussion

In an EPA document last updated in 2012, EPA noted that NORM and technologically enhanced naturally occurring radioactive material (TENORM) from oil and gas development are managed in several ways.

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[14] An alpha particle is “a positively charged particle made up of two neutrons and two protons emitted by certain radioactive nuclei. Alpha particles can be stopped by thin layers of light materials, such as a sheet of paper, and pose no direct or external radiation threat; however, they can pose a serious health threat if ingested or inhaled” (EPA, Radiation Protection, Radiation Glossary, http://www.epa.gov/radiation/glossary/index.html)

[15] Gamma rays are “high-energy electromagnetic radiation emitted by certain radionuclides when their nuclei transition from a higher to a lower energy state. These rays have high energy and a short wave length. All gamma rays emitted from a given isotope have the same energy, a characteristic that enables scientists to identify which gamma emitters are present in a sample. Gamma rays are very similar to x-rays” (EPA, Radiation Protection, Radiation Glossary, http://www.epa.gov/radiation/glossary/index.html).

Produced waters are generally reinjected into deep wells. Sludges containing elevated TENORM are dewatered and held in storage tanks for later disposal. Pipes contaminated with scale are cleaned at pipe yards either by sandblasting them with high pressure water or by scraping out the scale with a rotating drill bit. The removed scale is then placed in drums and stored for later disposal. Contaminated equipment may be cleaned and reused by the petroleum industry; disposed; or, if radiation levels are sufficiently reduced, sold for recycle. If equipment cannot be further decontaminated to acceptable levels, it is sent to a licensed landfill (EPA, Radiation Protection, Oil and Gas Production Wastes, www.epa.gov/radiation/tenorm/oilandgas.html).

Produced waters contain levels of radium and its decay products, but the concentrations vary from site to site. EPA identifies the range for produced water as 0.1 picocuries per liter (pCi/L) to 9,000 pCi/L (EPA, Radiation Protection, Oil and Gas Production Wastes, www.epa.gov/radiation/tenorm/oilandgas.html). The Pennsylvania Department of Environmental Protection has undertaken a study of NORM in material associated with oil and gas development. According to PA DEP, the study will "analyze the radioactivity levels in flowback waters, treatment solids and drill cuttings, as well as issues with transportation, storage and disposal of drilling wastes, the levels of radon in natural gas, and potential exposure to workers and the public" (Oil and Gas Related Topics: Radiation Protection, www.portal.state.pa.us/portal/server.pt/community/oil___gas_related_topics/20349/radiation_protection/986697). The samples have been analyzed and once data analysis, report preparation and review are completed, a final report is to be released, probably by the end of 2014.

Adgate et al. (2014) report that evidence suggested that wastewater is more effectively treated onsite rather than at publicly owned treatment plants, which may not be able to provide sufficient treatment for this wastewater. Maryland has decided not to allow the treatment of flowback or produced water at publicly owned treatment plants, at least until EPA has developed pretreatment regulations. Even with pretreatment, because of the elevated levels of salts, it may not be feasible to treat this wastewater at any facility that discharges to fresh water. A large portion of flowback and produced water are now recycled, either on site or at a central facility. The water is used to hydraulically fracture additional wells, and the solid residue is dewatered and disposed of in a licensed landfill.

The Interim Final Best Practices Report (MDE and DNR, 2014b) identified steps to address radioactive wastes: "Cuttings, flowback, produced water, residue from treatment of flowback and produced water, and any equipment where scaling or sludge is likely to occur shall be tested for radioactivity and disposed of in accordance with law" (p. 50). Some have expressed concern that the methods used to detect radiation are inadequate to quantify the radiation in hydraulic fracturing wastes. EPA (2014) recently released a white paper entitled "Development of Rapid Radiochemical Method for Gross Alpha and Gross Beta Activity Concentration in Flowback and Produced Waters from Hydraulic Fracturing Operations." This updated method can analyze gross alpha and gross beta activity within about 24 hours after the sample is received at the laboratory. Gamma radiation is measurable by a large variety of devices that could easily be used at the well pad.

Unlike some states, Maryland has not established a radiation limit for wastes sent to municipal waste landfills for disposal, nor are such landfills uniformly required to test incoming wastes for radioactivity.

Such landfills are, however, lined with leachate collection systems and groundwater monitoring. Work is underway to develop regulations to address these issues in advance of any Marcellus Shale drilling in Maryland.

Before a well can be hydraulically fractured, the casing and cement in the target formation must be perforated and an initial entry must be made into the formation. This is accomplished in stages along the horizontal borehole by using a perforating gun that contains several shaped charges -- explosive devices that can be directed to create a perforation tunnel in the desired direction. These small devices are inserted into the well and set off from the surface. It has been noted that patents exist for shaped charges that contain depleted uranium. The Departments have not been able to confirm that such devices are being used anywhere in the United States. Applicants for well permits will be required to disclose if they intend to use shaped charges containing depleted uranium. The Departments will require monitoring to identify any radiation risk and require proper handling and disposal of radioactive materials.

Conclusion

Sufficient controls are, or will be, in place to assure proper management of any NORM and TENORM that would be generated if Marcellus Shale drilling is allowed in Maryland.

F. Use and Disclosure of Chemicals

Background

Quantities of chemicals are brought to the drill site and used there. Spills or other releases of these chemicals at the surface are of concern to the community. In addition, chemicals are added to drilling fluid and hydraulic fracturing fluid. The identity of chemical additives to drilling fluids and hydraulic fracturing fluids is of particular concern because these chemicals are used underground where, if appropriate precautions are not taken, the chemicals could enter underground sources of drinking water. At the federal level, the Safe Drinking Water Act (SDWA) allows EPA to regulate the subsurface emplacement of fluid; however, Congress excluded from regulation under the SDWA the underground injection of fluids (other than diesel fuels) and propping agents for high volume hydraulic fracturing. Many oil and gas companies voluntarily disclose the chemicals they use in hydraulic fracturing, although the specific identity of some chemicals are withheld because the companies that market them claim that the chemical or the formulation is confidential commercial information, often referred to as a trade secret.

Other federal and State laws do require the disclosure of information about hazardous chemicals to workers, consumers, and local and state emergency response authorities. The information is commonly provided in the form of a Safety Data Sheet (formerly called Material Safety Data Sheets). A Safety Data Sheet must contain the following information about hazardous chemicals, although in the case of confidential commercial information, the exact name of the chemical constituent or concentration may be withheld:

- Identification

- Hazard(s) identification
- Composition/information on ingredients
- First-aid measures
- Fire-fighting measures
- Accidental release measures
- Handling and storage
- Exposure controls/personal protection
- Physical and chemical properties
- Stability and reactivity
- Toxicological information

Data and Discussion

Drilling additives. Drilling fluid facilitates the drilling process by lubricating and cooling the drill bit, transporting cuttings up the borehole to the surface and preventing them from settling when the drilling is suspended, and exerting enough pressure to prevent the collapse of the borehole and the entry into the borehole of liquids or gases from the surrounding rock. The drilling fluid can be water-based, oil-based, or synthetic-based. Compressed air or other gaseous substances are sometimes used. Drilling fluids often contain chemicals that adjust viscosity, add weight, or reduce friction. An aqueous drilling fluid would generally be composed of the following chemicals by weight: brine/water (76 percent), barite (14 percent), clay/polymer (6 percent) and other chemical additives (4 percent). A non-aqueous drilling fluid would generally be composed of the following chemicals by weight: non-aqueous fluid (46 percent), barite (33 percent), brine (18 percent), emulsifiers (2 percent), and gellants/other chemical additives (1 percent) (IPIECA 2009). As drilling fluid returns to the surface, cuttings are separated using equipment on site and the drilling fluids are reused.

Fracturing additives. Fracturing fluid is composed of water, proppant and additives. According to FracFocus, a national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, there are hundreds of chemicals that could be used as additives, but a limited number are routinely used. "A typical fracture treatment will use very low concentrations of between 3 and 12 additive chemicals, depending on the characteristics of the water and the shale formation being fractured" (FracFocus, Chemical Use in Hydraulic Fracturing, http://fracfocus.org/water-protection/drilling-usage).

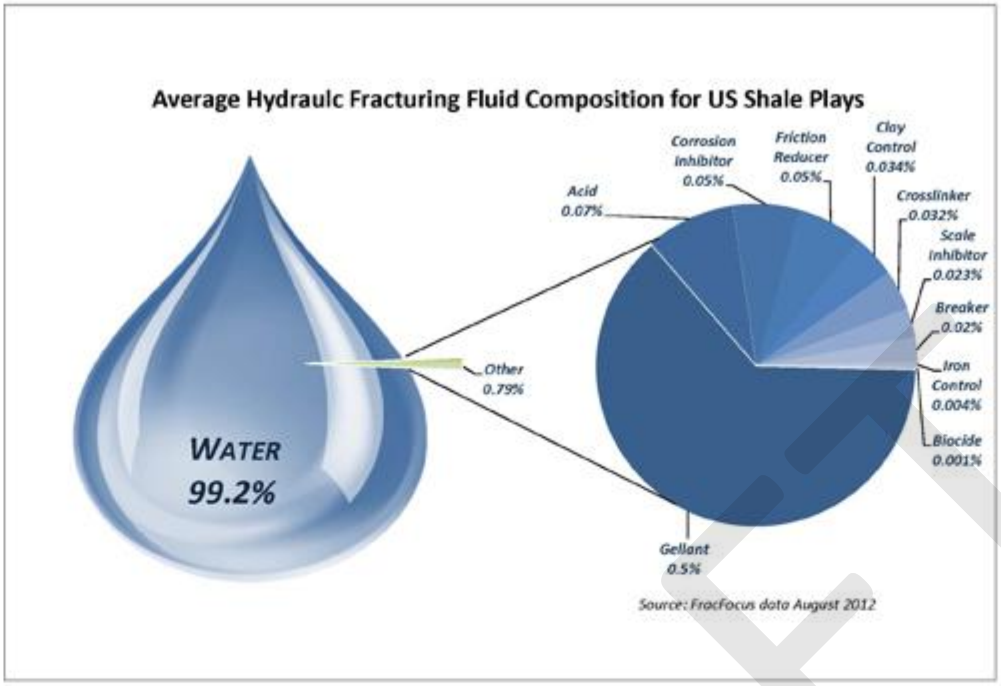

Figure 3. Average Hydraulic Fracturing Fluid Composition
Source: ALL Consulting from FracFocus website, http://fracfocus.org/water-protection/drilling-usage

The FracFocus website displays the following chart, which illustrates the average volumetric percentages of additives used for hydraulic fracturing treatment in various unconventional oil and gas plays.

The FracFocus website provides the following list of chemicals used most often in hydraulic fracturing. Some chemicals appear more than once in the chart because they serve more than one function. The chart is sorted by product function.

Chemical Name	CAS[16]	Chemical Purpose	Product Function
Hydrochloric Acid	007647-01-0	Helps dissolve minerals and initiate cracks in the rock	Acid
Glutaraldehyde	000111-30-8	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Quaternary Ammonium Chloride	012125-02-9	Eliminates bacteria in the water that produces corrosive by-products	Biocide

[16] A CAS number is a unique number assigned by the Chemical Abstract Service to each chemical entity.

Chemical Name	CAS[16]	Chemical Purpose	Product Function
Quaternary Ammonium Chloride	061789-71-1	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Tetrakis Hydroxymethyl-Phosphonium Sulfate	055566-30-8	Eliminates bacteria in the water that produces corrosive by-products	Biocide
Ammonium Persulfate	007727-54-0	Allows a delayed break down of the gel	Breaker
Sodium Chloride	007647-14-5	Product Stabilizer	Breaker
Magnesium Peroxide	014452-57-4	Allows a delayed break down the gel	Breaker
Magnesium Oxide	001309-48-4	Allows a delayed break down the gel	Breaker
Calcium Chloride	010043-52-4	Product Stabilizer	Breaker
Choline Chloride	000067-48-1	Prevents clays from swelling or shifting	Clay Stabilizer
Tetramethyl ammonium chloride	000075-57-0	Prevents clays from swelling or shifting	Clay Stabilizer
Sodium Chloride	007647-14-5	Prevents clays from swelling or shifting	Clay Stabilizer
Isopropanol	000067-63-0	Product stabilizer and / or winterizing agent	Corrosion Inhibitor
Methanol	000067-56-1	Product stabilizer and / or winterizing agent	Corrosion Inhibitor
Formic Acid	000064-18-6	Prevents the corrosion of the pipe	Corrosion Inhibitor
Acetaldehyde	000075-07-0	Prevents the corrosion of the pipe	Corrosion Inhibitor
Petroleum Distillate	064741-85-1	Carrier fluid for borate or zirconate crosslinker	Crosslinker
Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for borate or zirconate crosslinker	Crosslinker

Chemical Name	CAS[16]	Chemical Purpose	Product Function
Potassium Metaborate	013709-94-9	Maintains fluid viscosity as temperature increases	Crosslinker
Triethanolamine Zirconate	101033-44-7	Maintains fluid viscosity as temperature increases	Crosslinker
Sodium Tetraborate	001303-96-4	Maintains fluid viscosity as temperature increases	Crosslinker
Boric Acid	001333-73-9	Maintains fluid viscosity as temperature increases	Crosslinker
Zirconium Complex	113184-20-6	Maintains fluid viscosity as temperature increases	Crosslinker
Borate Salts	N/A	Maintains fluid viscosity as temperature increases	Crosslinker
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Crosslinker
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Crosslinker
Polyacrylamide	009003-05-8	“Slicks” the water to minimize friction	Friction Reducer
Petroleum Distillate	064741-85-1	Carrier fluid for polyacrylamide friction reducer	Friction Reducer
Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for polyacrylamide friction reducer	Friction Reducer
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Friction Reducer
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Friction Reducer

Chemical Name	CAS[16]	Chemical Purpose	Product Function
Guar Gum	009000-30-0	Thickens the water in order to suspend the sand	Gelling Agent
Petroleum Distillate	064741-85-1	Carrier fluid for guar gum in liquid gels	Gelling Agent
Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for guar gum in liquid gels	Gelling Agent
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Gelling Agent
Polysaccharide Blend	068130-15-4	Thickens the water in order to suspend the sand	Gelling Agent
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Gelling Agent
Citric Acid	000077-92-9	Prevents precipitation of metal oxides	Iron Control
Acetic Acid	000064-19-7	Prevents precipitation of metal oxides	Iron Control
Thioglycolic Acid	000068-11-1	Prevents precipitation of metal oxides	Iron Control
Sodium Erythorbate	006381-77-7	Prevents precipitation of metal oxides	Iron Control
Lauryl Sulfate	000151-21-3	Used to prevent the formation of emulsions in the fracture fluid	Non-Emulsifier
Isopropanol	000067-63-0	Product stabilizer and / or winterizing agent.	Non-Emulsifier
Ethylene Glycol	000107-21-1	Product stabilizer and / or winterizing agent.	Non-Emulsifier

Chemical Name	CAS[16]	Chemical Purpose	Product Function
Sodium Hydroxide	001310-73-2	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Potassium Hydroxide	001310-58-3	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Acetic Acid	000064-19-7	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Sodium Carbonate	000497-19-8	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Potassium Carbonate	000584-08-7	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent
Copolymer of Acrylamide and Sodium Acrylate	025987-30-8	Prevents scale deposits in the pipe	Scale Inhibitor
Sodium Polycarboxylate	N/A	Prevents scale deposits in the pipe	Scale Inhibitor
Phosphonic Acid Salt	N/A	Prevents scale deposits in the pipe	Scale Inhibitor
Lauryl Sulfate	000151-21-3	Used to increase the viscosity of the fracture fluid	Surfactant
Ethanol	000064-17-5	Product stabilizer and / or winterizing agent.	Surfactant

Chemical Name	CAS[16]	Chemical Purpose	Product Function
Naphthalene	000091-20-3	Carrier fluid for the active surfactant ingredients	Surfactant
Methanol	000067-56-1	Product stabilizer and / or winterizing agent.	Surfactant
Isopropyl Alcohol	000067-63-0	Product stabilizer and / or winterizing agent.	Surfactant
2-Butoxyethanol	000111-76-2	Product stabilizer	Surfactant

Table 7. Chemicals commonly used in hydraulic fracturing
Source: modified from FracFocus website

Some of these chemicals are known or suspected carcinogens and can cause other adverse human health impacts. Others commonly appear in consumer products and some have been approved as food additives. Although fracturing fluid additives comprise a relatively small fraction of the total volume of fracturing fluid, the volume of fracturing fluid needed for a single fracturing fluid operation is substantial, which makes the total volume of additives needed significant (Ernstoff & Ellis, 2013; Rozell & Reaven, 2012).

The Maryland Department of the Environment routinely requested information on drilling and fracturing additives as part of the application for a permit to drill an oil or gas well. The applicant commonly supplied Safety Data Sheets for the products it bought to use as additives. If the manufacturer of the product considered the specific chemical identity or concentration to be confidential commercial information, these would not appear on the Safety Data Sheet.

In the Interim Final Best Practices Report (MDE and DNR, 2014a), the Departments established requirements for disclosure. These include:

- The disclosure to MDE of all chemicals that the applicant expects to use on the site, not just chemicals classified as “hazardous chemicals” under the OSHA Hazard Communication Standard.
- Submission to MDE of a complete list (Complete List) of chemical names, CAS numbers, and concentrations of every chemical constituent of every commercial chemical product brought to the site. The information must be provided even if there is a claim of trade secrecy; in this case, the Department will retain the list, but the list will not be considered public information.
- If a claim is made that the composition of a product is a trade secret, the permittee must also provide an alternative list (Alternative List), in any order, of the chemical constituents, including CAS numbers, without linking the constituent to a specific product.
- If no claim of trade secret is made, the Complete List will be considered public information; if a claim is made, the Alternative List will be considered public information.

- The Departments will require disclosure of chemicals used on FracFocus, so that the FracFocus data base can be more nearly complete and useful; however, the Departments are aware that FracFocus has different requirements, and will not always identify the chemical.
- The operator must provide to the local emergency response agency: a) the Complete List or Alternative List of all chemical constituents and b) Safety Data Sheets for all products that contain one or more OSHA hazardous chemicals, as that term is defined by the Occupational Safety and Health Administration of the United States Department of Labor.
- The operator must provide to the public, upon request, the same information made available to the local emergency response agency. If the permittee provides the information to MDE in a format MDE specifies, MDE will post the information on its website at least until the well completion report is filed, and this will be deemed to satisfy the operator's obligation to provide the information to the public.
- A person claiming a trade secret must substantiate and attest to the claim when it is submitted to MDE, but MDE will not evaluate whether the claim is legitimate. MDE will keep the information confidential, but may share it with other State and federal agencies that agree to protect the confidentiality of the information. If a request is made for the trade secret information under the Maryland Public Information Act, a process exists for challenging the claim. MDE will require the entity claiming trade secret protection to defend against any challenge.
- A person claiming trade secret must provide the supplier's or service company's contact information, including the name of the company, an authorized representative, and a telephone number answered 24/7 by a person with the ability and authority to provide the trade secret information in accordance with the regulations.
- The regulations will require that information furnished under a claim of trade secret be provided by the person claiming the trade secret to a health professional who states, orally or in writing, a need for the information to diagnose or treat a patient. The health professional may share that information with other persons as may be professionally necessary, including, but not limited to, the patient, other health professionals involved in the treatment of the patient, the patient's family members if the patient is unconscious, unable to make medical decisions, or is a minor, the Centers for Disease Control, and other government public health agencies. Any recipient of the information disclosed under this regulation shall not use the information for purposes other than the health needs asserted in the request and shall otherwise maintain the information as confidential. Information so disclosed to a health professional shall in no way be construed as publicly available. The holder of the trade secret may request a confidentiality agreement from all health professionals to whom the information is disclosed as soon as circumstances permit, but disclosure may not be delayed in order to secure a confidentiality agreement.
- Upon written request and statement of need for public health purposes, the person claiming the trade secret will disclose the chemical identity and percent composition to any health professional, toxicologist or epidemiologist who is employed in the field of public health,

including such persons employed at academic institutions who conduct public health research. The recipient may share the information as professionally necessary. Any recipient of the information disclosed under this regulation shall not use the information for purposes other than the public health needs asserted in the request and shall otherwise maintain the information as confidential. Information so disclosed to a health professional, toxicologist or epidemiologist shall in no way be construed as publicly available. Disclosure may be conditioned on the signing of a confidentiality agreement before disclosure. Publication of research results without revealing any trade secret information is not precluded. For example, provided the publication does not disclose the trade name of the commercial product subject to trade secret protection, or the identity of the manufacture or distributor of the product, research that utilizes trade secret information may be published.

- Following well completion, the operator shall provide MDE with a list of all chemicals used in fracturing, the weight of each used, and the concentration of the chemical in the fracturing fluid. If a claim is made that the weight of each chemical used or the concentration of each chemical in the fracturing fluid is a trade secret, the operator may attest to that fact and provide a second list that omits the weight and concentration to the extent necessary to protect the trade secret. If no claim of trade secret is made, the full list shall be public information; if a claim of trade secret is made, the list without the trade secret weight and concentration shall be public information.

Maryland law recognizes the legitimacy of confidential commercial information and the Legislature has adopted the Uniform Trade Secrets Act in the Commercial Law Article, Title 11, Subtitle 12. In addition, the Public Information Act requires State agencies to deny inspection of any part of a public record that contains a trade secret or confidential commercial information. General Provisions Article, Section 4-335. In light of this State policy, the Departments considered how to address the disclosure of chemical trade secrets while at the same time performing its obligations to protect the public and the environment from hazards.

The public could be exposed to the commercial products themselves in the event of a release of the product in transport or from the well pad. The emergency response agency would have sufficient information from the Safety Data Sheets to respond to the release. If any emergency responder or member of the public was exposed to the product itself, a physician could obtain the precise chemical makeup of the product under the disclosure rules.

If the product had already been used in the drilling or fracturing fluid before a member of the public were exposed, the concentration of the constituents would have changed and the constituents themselves may have reacted to produce different chemicals. In this case, information about the makeup of the product before it was used would be of limited use. The identity of all the chemicals in the product would appear, however, on the Alternative List. This list would also be available to inform any monitoring program of air or water.

Conclusion

The issue of chemical disclosure involves competing legitimate interests. The government must have the information it needs to fulfill its mission. The public has an interest in knowing what chemicals are being used in their communities. The company that developed a useful product has a right to protect its trade secret. We have balanced all these interests by requiring that the identity of all chemicals must be disclosed, allowing companies to protect the confidential commercial information of the exact formulation of its products, and assuring that medical professionals have access to the information when it is needed.

G. Use of Fresh Water

Background

Large quantities of water are required for unconventional gas development for both the drilling and the hydraulic fracturing phase. Maryland's risk assessment assumes that an average of five million gallons of water is required for each well with the majority of water used for hydraulic fracturing. It is anticipated that water will be supplied by permitted fresh water withdrawals from surface and ground water resources, and possibly purchases from public water systems.

If improperly managed, fresh water withdrawals could impact local and regional water supplies, degrade aquatic ecosystems and affect water dependent recreational uses. Withdrawals are considered permanent since the water is generally not returned to the system and may reduce availability of fresh water for existing and future uses, as well as downstream users. Withdrawals from streams and rivers or from the ground water that feeds these flowing aquatic habitats could adversely affect aquatic ecosystems by reducing flow and water levels and negatively affecting stream chemistry by increasing temperature and reducing dissolved oxygen. In western Maryland, there are many aquatic species, including Brook trout, which require cool, clean and aerated streams in order to thrive and reproduce. Recreational uses also need to be accounted for as withdrawals are planned and permitted in order that boating, fishing, and other water dependent uses are not impacted. While any freshwater withdrawal, no matter the reason, could impact a range of uses, it is the compressed time frame of water demands that is unique to unconventional gas development. The rate of withdrawal that results from large quantities of water removed over short time spans must also be considered as water appropriation permits are developed.

Data and Discussion

Maryland's assessment of risks estimates that the total water demand for unconventional gas development could range from a low of 75 million gallons per year to 360 million gallons per year depending on the rate and intensity of extraction. To put this in context, during a year with average precipitation, over 1.3 billion gallons of water falls on Garrett County, on average, each day. At the level of a single well, risks are expected to be low and infrequent. The Interim Best Practices report (MDE and DNR, 2014a) states that the thresholds set by Maryland's water appropriation program for requiring a permit indicate that sufficient water could not be obtained without a permit. Maryland is satisfied that existing criteria used to evaluate water appropriations are generally adequate to address water withdrawals for unconventional gas development. These criteria are designed to ensure that enough water, both in quantity and flow, remain to support existing uses and healthy aquatic ecosystems.

The Interim Best Practices report also provides additional protection through the CGDP by requiring a generalized water appropriation plan which will identify the proposed locations and amounts of water withdrawals needed to support the plan. This early planning will allow MDE to flag any proposed appropriations that may not be granted due to supply, environmental, public health or other restrictions. Additionally, the CGDP could lead to improved management of fresh water supplies throughout the lifetime of the plan by a better understanding of cumulative impacts from existing and proposed appropriations. About 30 percent of the water used for hydraulic fracturing in Marcellus Shale returns as flow back, along with some water from the Marcellus Shale formation called “produced water.” The overall water demands will be reduced by requiring the companies to recycle 90 percent of flow back and produced water unless the applicant can demonstrate that it is not practicable.

The risk ranking for impacts to ecological systems and aquatic species is medium (probability = medium, consequence = moderate) because some aquatic species may be sensitive to relatively minor decreases in water levels or flow which not otherwise cause appreciable impacts on other uses. Certain aquatic habitats, such as the headwater areas of Use Class III (cold water) and Tier II streams are highly sensitive to alterations in flow and stream chemistry. If withdrawals coincide with periods of droughts, adverse impacts could occur. The coincidence of multiple stressors is unpredictable and results in the medium risk ranking.

Conclusion

Maryland’s water appropriation program is stringent enough to generally protect all users of fresh water resources in western Maryland. While unconventional gas development consumes large amounts of water, the available supplies are extensive and can easily accommodate these prospective demands. Recycling and advances in technology that may reduce water needs for drilling and hydraulic fracturing will further lighten the demands on available supplies. However, caution must be given to the timing and rate of withdrawals and to specific locations which are highly sensitive; a consideration that is addressed through the CGDP. Additional practices that could reduce risks include 1) counties establishing one or more semi-permanent access points at a source with large capacity and storage options, 2) requiring applicants to perform additional modeling for impact assessment in sensitive locations, such as Use III and Tier II waters and 3) MDE and DNR developing additional scientific guidance for monitoring and assessing potential ecological impacts to sensitive streams.

H. Greenhouse Gas Emissions

Background

The climate impact of natural gas is generally evaluated in two ways: the lower CO_2 emissions per kilowatt-hour of electricity generated by burning natural gas instead of coal, and the greenhouse gas impacts of methane that enters the atmosphere by fugitive emissions and leaks. If only the emissions related to combustion in power plants are considered, natural gas emits about half as much CO_2 as coal per kilowatt-hour generated. Methane itself, however, is a powerful greenhouse gas. It forces about 85 times the global warming of CO_2 in its first 20 years and about 30 times after 100 years. [17]

There have been varying estimates of the amount of methane that escapes to the atmosphere from production, transmission, and distribution of natural gas. Estimates have been made using emission factors, on site measurements, and atmospheric measurements. The range of estimates has been large, and the issue cannot be considered settled.

Data and Discussion

According to Jackson et al., (2014) EPA's estimates for methane emissions from natural gas production operations have changed over the years, and range from between <0.2 percent and 1.5 percent. In 2013, EPA estimated a total leak rate of natural gas from production to be about 0.49 percent of total gross production, and the total leak rate from well to end user of 1.4 percent.

A study by Allen et al. (2013) based on detailed measurements estimated production losses to be approximately 0.42 percent of gross production, slightly less than the EPA estimate. Uncertainties in measurements and sampling and limited sampling size contributed to a large confidence interval. Jackson noted that this study found large differences in process-level emissions across regions and the presence of large emitters in most regions. Jackson, et al. (2014) noted that atmospheric studies found regional-scale leaking rates to be 4 percent in the oil and gas producing Denver Basin in Colorado and 6.2 percent to 11.7 percent in the Uinta Basin in Utah.

A review of 20 years of data emissions from natural gas systems in the United States and Canada found:

> (i) measurements at all scales show that official inventories consistently underestimate actual CH_4 emissions, with the NG [natural gas] and oil sectors as important contributors; (ii) many independent experiments suggest that a small number of "superemitters" could be responsible for a large fraction of leakage; (iii) recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical NG system leakage rates; and (iv) assessments using 100-year impact indicators show system-wide leakage is unlikely to be large enough to negate climate benefits of coal-to-NG substitution. (Brandt et al., 2014)

A 2012 article by Alvarez et al. examined the impact of leakage for generating electricity (well-to-burner-tip) and for fueling vehicles (wells-to-wheels). With regard to electricity, the authors stated "We estimate that natural gas produces net climate benefits relative to low-gassy coal on all time frames as long as leakage in the natural gas system is less than 3.2 percent from well through delivery at a power plant (i.e., excluding the local distribution system)." With regard to the use of natural gas as fuel for

[17] The decline from 85 to 30 is due to the rate at which methane is removed from the atmosphere; methane has a relatively short perturbation lifetime. The Perturbation Lifetime (PL) is a standard way of characterizing how long molecules remain in the atmosphere. Methane is estimated to have a PL of 12.4 years, while nitrous oxide (N_2O) has a PL of 121 years. Myhre, G., D. et al., 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, Table 2.1 and Appendix 8A.

vehicles, however, the authors concluded that even lower leakage rates would be needed to produce near-term climate benefits for natural gas as a transportation fuel due to the lower carbon intensity (relative to coal) of the fuels natural gas would replace (gasoline and diesel).

> [I]f the well-to-wheels leakage was reduced to an effective leak rate of 1.6% of natural gas produced..., CNG [compressed natural gas] cars would result in climate benefits immediately and improve over time. For CNG to immediately reduce climate impacts from heavy-duty vehicles, well-to-wheels leakage must be reduced below 1%.

Given that the primary niche for natural gas as a transportation fuel is heavy duty vehicles (replacing diesel), its climate benefits as a transportation fuel appear more dubious. Also, the authors cautioned that although the benefits increase over the long term (i.e. decades) as the large radiative forcing of methane diminishes, the short term may be more important:

> Determining whether a unit emission of CH_4 is worse for the climate than a unit of CO_2 depends on the time frame considered. Because accelerated rates of warming mean ecosystems and humans have less time to adapt, increased CH_4 emissions due to substitution of natural gas for coal and oil may produce undesirable climate outcomes in the near-term.

An analysis by Climate Central (2014) provided a tool to answer the question of the global warming impact of switching from coal to natural gas for generation of electricity using different methane leak rates and coal-to-gas conversion rates, projected to 2110. At a 1 percent conversion rate, gas is better than coal for all years until the methane leak rate approaches 5 percent. Using a 2 percent leak rate and a conversion rate of coal to gas sufficient to achieve a 25 percent reduction in coal use by 2030, the tool predicts that by 2030 greenhouse gas emissions from the electricity sector would be about 10 percent lower than today and, that by 2060, the reduction would reach 24 percent.

Another study (Burnham & Clark, 2012) also looked at the impacts of expanded use of natural gas in both electricity generation and transportation. The authors identified emissions from shale gas well completions and emissions from conventional natural gas liquid unloading as important upstream production activities and assumed that downstream emissions for shale and conventional gas would be similar. The analysis showed that shale gas was better than conventional gas and that both were better than coal from a global warming potential for power plants on a 100-year timeframe. The benefit is diminished but does not disappear for the 20-year timeframe. There was no statistical difference between vehicles using petroleum or compressed natural gas (CNG) on the 100-year timeframe, but emissions were about 25 percent higher for CNG vehicles for the 20-year timeframe. The authors noted that there was considerable uncertainty in the data for emissions from conventional gas well liquid unloadings and shale gas well completions and for estimated ultimate recovery. They cautioned that the uncertainties could potentially support erroneous conclusions.

A recent article (McJeon et al., 2014) evaluated the impact up to the year 2050 of increased use of natural gas on climate change for two scenarios: a conventional gas scenario and an abundant gas scenario. The authors modeled the impact using five different integrated assessment models that represent prices, demand, and supply for different fossil fuels and low-carbon energy sources. The uses were not limited to power production. The models were run based upon climate change policies already in effect, and did not simulate future climate policies.

The model results showed that abundant natural gas leads to greater consumption of natural gas. Coal loses the largest market share to natural gas, but natural gas also gains market share at the expense of nuclear and renewables. Overall, low-cost, abundant natural gas leads to increased economic activity, reduced incentive for energy efficiency, and an overall expansion of the total energy use. The five models predicted that the impact of abundant natural gas on CO_2 emissions would range from negative 2 percent to positive 11 percent, and the impact on climate forcing would range from negative 0.3 percent to positive 7 percent.

The authors noted:

> The core finding of this research is that increases in unconventional gas supply in the energy market could substantially change the global energy system over the decades ahead without producing commensurate changes in emissions or climate forcing. The result stems from three effects: abundant gas substituting for all energy sources; lower energy prices increasing the scale of the energy system; and changes in non- CO_2 emissions. This result is potentially sensitive to a range of model assumptions.

Among the assumptions that could alter the result are: policies that would restrict the use of natural gas as a substitute for low-carbon energy; technology changes that make other forms of energy more available or less expensive; and changing rates of fugitive methane emissions. The authors also noted that climate change is not the only implication of abundant natural gas, which can also positively affect air and water quality[18], energy security, access to modern energy, and economic growth.

Reduced emissions completion, discussed above under Air Pollution, will reduce the amount of methane emitted during well completion. Among the other practices to reduce methane emissions that Maryland regulations will require are a leak detection and repair program, limitations on flaring, a minimum destruction efficiency for flares, and top-down BAT for other equipment on the well pad that can emit methane. When evaluating top-down BAT, the applicant for the permit will be required to consider, to

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[18] Emissions of mercury from burning natural gas are negligible. Burning coal for energy production has been the single largest component of anthropogenic mercury emissions in the United States, accounting for more than half the total. Wentz, D.A., Brigham, M.E., Chasar, L.C., Lutz, M.A., and Krabbenhoft, D.P., 2014, *Mercury in the Nation's streams—Levels, trends, and implications*: U.S. Geological Survey Circular 1395, 90 p., http://dx.doi.org/10.3133/cir1395. The report stated "Mercury is a potent neurotoxin that accumulates in fish to levels of concern for human health and the health of fish-eating wildlife. Mercury contamination of fish is the primary reason for issuing fish consumption advisories, which exist in every State in the Nation. Much of the mercury originates from combustion of coal and can travel long distances in the atmosphere before being deposited." The study found that methylmercury concentrations in fish exceeded levels protective of human health in about one in four streams across the United States. The Maryland Department of the Environment has issued statewide advisories for gamefish and panfish in all freshwater lakes, streams, and rivers and has also monitored mercury levels of numerous species inhabiting the Chesapeake Bay and other tidal waters.

the extent they apply to the applicant's operations, EPA's Natural Gas STAR Program's Recommended Technologies and Practices (www.epa.gov/gasstar/tools/recommended.html).

Even with these controls, some methane will escape. MDE will require permittees to estimate all of the remaining methane emissions and offset them with greenhouse gas credits. The permittees will have to estimate and report emissions to the State annually. Where practicable, estimates should be verified by operational data from the permittee's leak detection and repair program. When estimating emissions, permittees must convert all methane emissions into CO_2-equivalent emissions. MDE will work with stakeholders to establish an offset program, building from ongoing efforts of the Regional Greenhouse Gas Initiative and other greenhouse gas offset initiatives across the country. MDE may also require permittees to offset leakage at a ratio greater than 1:1.

Conclusion

These articles support a conclusion that minimizing fugitive emissions of methane, as will be required in Maryland regulations, is necessary to realize any significant radiative forcing advantage over coal and oil. Improved energy efficiency, greater reliance on sources of power other than fossil fuels, and good climate policy will be necessary to address climate change regardless of changes in the use of natural gas.

I. Impacts on Habitat and Natural Resources

Background

Western Maryland has some of the state's most important natural areas and offers diverse outdoor recreational opportunities that rely on exceptionally high value natural resources. Shale outcroppings, ridgelines, expansive swaths of intact forests, cave formations and clean, cold water streams provide unique habitats for diverse and abundant aquatic and terrestrial living resources. Maryland's GreenPrint identifies the most ecologically important waters and lands in the State and prioritizes these areas, referred to as "Targeted Ecological Areas", for land conservation projects. (Maryland Greenprint, http://greenprint.maryland.gov/.) Garrett County ranks highest in the State as the county with the greatest amount of GreenPrint resources. Seventy-seven percent of the county has been mapped as GreenPrint and about thirty percent is protected. Allegany County ranks fourth across the State for GreenPrint resources. Sixty-five percent of the county's land is within the GreenPrint and forty-two percent is protected. Within the GreenPrint, certain habitats have been designated as "Irreplaceable Natural Areas" because if they are lost through surface development, the habitats and species they support will not recover. Many of western Maryland's rare, threatened and endangered species, such as the northern goshawk, green salamander, summer sedge, Indiana bat and eastern hellbenders are found within these Irreplaceable Natural Areas. A high number of Tier II stream segments are found within this region. Tier II streams are designated through the Clean Water Act as high quality waters and Maryland is required to protect and maintain these streams. Many Tier II stream segments fall within the Savage River watershed which supports the State's most productive and interconnected stream system of Brook trout.

Direct impacts from unconventional gas development include the conversion of lands supporting forests, fields, and other natural resources to industrial use resulting from the well pad footprint and associated infrastructure such as roads, pipelines and compressor stations. Maryland's risk assessment (MDE and DNR, 2014b) estimates that the land use footprint per well pad would be about fifteen acres, which includes 4 acres for the well pad with the remainder needed for supporting infrastructure. Depending on the intensity of shale gas development, the direct impact of land conversion could range from 375 acres to 1,125 acres which would consume between 0.07 percent to 0.22 percent of the 508,200 acres of land within the Marcellus Shale exploration area. Habitats and natural resources are also adversely affected by associated impacts resulting from habitat fragmentation, watershed development and stream crossings. The risk assessment estimates that 1.65 miles of gathering pipelines are needed for each new well pad. As gathering lines traverse the landscape to collect and transmit produced gas to consumer markets, forested landscapes will be fragmented and streams will be crossed. Forest fragmentation reduces the available deep forest interior habitats that certain species, many of them birds, require for feeding and reproduction. Stream crossings invariably disrupt stream habitat and can lead to increased in-stream sedimentation and bank erosion. Certain high value watersheds, such as those containing Tier II streams, Brook trout populations or other pollution intolerant fish and aquatic insects are very sensitive to land use changes. Eshleman and Elmore (2013) point out that unconventional well development increases the amount of industrialized land use within a watershed which ecologically acts like impervious surface. Increases of impervious surface at a watershed scale are correlated with a decrease in aquatic biological diversity to due increased degradation of the physical and chemical environments of streams. In western Maryland, brook trout is almost entirely restricted to watersheds with less than 4 percent impervious surfaces.

Data and Discussion

The Interim Final Best Practices report (MDE and DNR, 2014a) proposes to protect habitats and natural resources through several measures. First, a suite of location restrictions and setbacks will prohibit well pad and permanent surface infrastructure development within high value and sensitive natural resource areas. For example, no well pads will be allowed within 450 feet of streams, rivers, wetlands, lakes, 100 year floodplains and other aquatic habitats. No surface development will be allowed to occur within 600 feet of special conservation areas, such as Irreplaceable Natural Areas and State designated Wildlands. No surface development will be allowed on public lands or within 1,000 feet of sensitive cave habitats. Development on steep slopes > 15 percent is restricted. Well pads cannot be developed within entire watersheds that supply drinking water for the Broadford Lake, Piney Reservoir and Savage Reservoir. These drinking water protections provide additional protection for the brook trout populations found within the Savage River watershed. The Interim Final Best Practices report indicates these restrictions would remove at least 83.2 percent (422,998 acres) of the land surface within the Garrett and Allegany county Marcellus Shale exploration area from surface development.

Impacts to ecological systems and farmland were ranked as moderate (probability = medium, consequence = moderate) during the site identification and preparation phase. It is inevitable that some resource land will be converted by pad and new road development and that the environmental damage will be localized. Most of this conversion would be of a temporary nature as site reclamation to pre-shale gas development conditions would be required, both during the reduction of the well pad foot print once all wells are completed and then at the terminal phase of well abandonment and reclamation.

Second, the CGDP provides an opportunity for landscape level planning for a company's entire planned operations over a five year period which gives State reviewers, the public and the applicant a means to minimize cumulative impacts to natural resources, as well as addressing community and public health concerns comprehensively, rather than on a piece-meal basis. In addition to assuring that all location restrictions, setbacks and other regulatory requirements are considered before permit applications are filed, the CGDP will adhere to a set of planning principles such as preferentially locating operations on disturbed open lands, or lands zoned for industrial activity, co-locating linear infrastructure with existing roads, pipelines and power lines, avoiding surface development beyond 2 percent in high value watersheds and minimizing fragmentation of interior forest habitat.

Concerns remain regarding the ecological risks associated with gathering lines which has been rated as moderate (probability = medium, consequence = moderate) under the 25 percent extraction scenario and high (probability = medium, consequence = serious) under the 75 percent extraction scenario. While the CGDP will serve to reduce the specific impacts of forest fragmentation and stream crossings, the ability to co-locate infrastructure and minimize impacts are limited because the siting of gathering lines is not regulated and is dictated by the willingness of property owners to enter into leasing agreements. Gathering lines are permanent alterations in that right of ways need to be maintained in a mown condition throughout the life of the line which could be 20 years or more. It is because of this permanence, uncertainty, and the clear knowledge that more well pads mean more gathering lines, that these moderate to high risks remain.

Additional practices to protect natural resources and habitat reflect operational procedures associated with lighting and noise management at the well pad to prevent disruption to species at sensitive lifecycle points, such as breeding or migratory stages. Rigorous invasive species management plans will be required to prevent accidental introduction of non-native invasive plants and animals through the transport and use of dry materials and fluids and site reclamation activities. Concerns have been noted in the risk assessment regarding the sensitivity of aquatic organisms to subsurface releases of flowback, fracturing fluid and produced water. These risks to ecological systems have been ranked as moderate (probability = low, consequence = serious). While the proposed best practices reduce the probability that these events will occur to low, an incident could provoke a system wide response if the contamination resulted in groundwater discharge to a headwater stream. Aquatic organisms are highly sensitive to dissolved toxins through exposure to gills, egg sacs and other hydrophilic membranes and are less able to move away from toxic environments. Cave systems and their unique biological communities are also particularly sensitive to groundwater toxins. The uncertainty regarding the specific chemical composition of fluids and the specific sensitivity of the exposed organisms warrants a greater consequence ranking.

Conclusion

The Interim Final Best Practices provide a rigorous set of protections for the abundant, diverse and sensitive habitats and natural resources of western Maryland. Extensive location restrictions and setbacks, along with landscape level planning through the CGDP provides a combination of best practices for that will achieve significant natural resource protection. Impacts from well pad development and new roads are moderate, but temporary, and avoid the State's most sensitive natural resources areas. Concerns remain regarding the impacts of gathering lines which will need to be addressed through the CGDP and through the development of siting and stream crossing guidelines designed to minimize impacts. Contamination of groundwater is unlikely, but should it occur, rigorous baseline and ongoing monitoring of groundwater and surface water resources should improve response times for addressing contamination pathways and reducing the extent of impact.

J. Impacts of Traffic

Background

Unconventional Gas Well Development using high volume hydraulic fracturing requires a substantial amount of truck traffic. Until recently, all materials, equipment, water, proppants, petroleum products, and chemicals have been transported to the well pad by truck, and this is still common. Because of the heavy truck traffic, communities near well pads may experience road damage, traffic congestion, traffic accidents, noise, and air pollution. There can also be ecological impacts, especially from the construction of new roads.

Data and Discussion

Federal highways are constructed to withstand heavy truck traffic. State and local roads are designed for the expected traffic, and trucks of certain sizes and weights may be prohibited. Overweight and oversize vehicles can be addressed through State and local permits, which can include provisions on times of travel, routes, liability, indemnity, and financial assurances. Most of the trucks associated with Marcellus Shale gas development, however, are neither overweight nor oversize. Damage and accelerated wear result from the sheer volume of trucks carrying legal loads on State and local roads that were not designed to accommodate that level of use. Road damage comes in the form of cracking, rutting, structural failure, and damage to traffic control devices and stormwater infrastructure along road sides. Bridges can also be structurally harmed.

Traffic congestion is a function of the numbers of trucks, the slower speed at which trucks climb long uphill stretches of road, and the need to stop traffic on narrow roads so trucks can pass. This can cause significant delays for residents using the roads and could impede the movement of emergency vehicles.

The number of accidents generally rises with increased traffic, but in some areas where shale drilling has been intense, the rate of traffic accidents or traffic deaths has gone up faster than population or vehicle miles traveled (Muehlenbachs & Krupnick, 2014; Begos & Fahey, 2014). Oil and gas extraction workers have a higher fatality rate than U.S. workers generally. During the 2003 to 2009 Census of Fatal Occupational Injuries, 716 oil and gas extraction workers were killed on-the-job, resulting in an annual fatality rate of 27.5 deaths per 100,000 workers (compared to 3.9 for all U.S. workers). Of these 716 deaths, 29 percent were highway motor vehicle crashes (CDC, 2012).

Traffic noise from trucks is closely related to the speed of the truck and how far the listener is from the truck. A truck going 50 miles an hour may register 8 decibels higher than a truck going 25 miles per hour. The sound level drops by 6 decibels each time the distance from the source is doubled. The sound from a single truck passing by would exist for a short time, but multiple truck trips along the same road would result in a higher equivalent continuous noise level (the total sound energy measured over an hour or other time period) and higher impacts on noise receptors close to main truck travel routes. (NYSDEC, 2011).

The Noise Control Act of 1972 empowered EPA to establish noise regulations for major sources, including transportation vehicles, and required EPA to issue noise emission standards for motor vehicles used in interstate commerce. The law requires the Federal Motor Carrier Safety Administration (FMCSA) to enforce the noise emission standards. In addition to standards for newly manufactured trucks, EPA has also established for existing medium and heavy trucks used in interstate commerce with a gross vehicle weight rating of more than 10,000 pounds. The standards are:

Speed	Maximum Noise Level 50 feet from Centerline of Travel
≤ 35 mph	83 dBA
> 35 mph	87 dBA
Stationary	85 dBA

Table 8. EPA noise levels for heavy trucks

The Maryland Department of Transportation has adopted maximum sound levels that apply to vehicles not used in interstate commerce. The standards are adjusted depending on whether the measurements are taken on a hard site[19], or a soft site[20]. The standards appear in regulations at COMAR 11.14.07.08:

Maximum Sound Levels Highway Operation				
Type of Vehicle	*Posted Speed Limit or Posted Advisory Speed*			
Any motor vehicle or combination having a GVWR or GCWR over 10,000 pounds	35 mph or less		Over 35mph	
	Soft Site	Hard Site	Soft Site	Hard Site
	86 dBA	88 dBA	90 dBA	92 dBA

Table 9. Maryland maximum sound levels for heavy trucks

Vehicles, particularly those with diesel engines, are a source of pollutants, including NOx, SO_2, hazardous air pollutants and particulate matter. The University of Maryland Institute for Applied Environmental Health (MIAEH, 2014) noted that "evidence from traffic-related air pollution studies indicated that the

[19] "Hard test site" means any test site having the ground surface covered with concrete, asphalt, packed dirt, gravel, or similar reflective material for more than 1/2 the distance between the microphone target point and the microphone location point. COMAR 11.17.07.02.

[20] "Soft test site" means any test site having the ground surface covered with grass, other ground cover, or similar absorptive material for 1/2 or more of the distance between the microphone target and the microphone location point. Id.

concentrations of traffic-related pollutants drop to the background level beyond 500-700m (1640-2296 feet)."

The construction of new roads for shale gas development may be limited to access roads from the nearest public roads to the well pad. Depending on where these access roads are located, they could fragment forests, cross streams or wetlands, or remove farmland from production. If erosion and sediment control are not employed, stream habitat can be damaged. Trucks on these roads are likely to stir up dust.

Among the recommendations in the Interim Final Best Practices Report that address the impact of truck traffic on the community and the environment are the following:

<u>Reducing the number of truck trips</u>. By encouraging the development of multiple wells on a single well pad, truck traffic related to pad construction, mobilization of the drill rigs, and delivery of equipment will be lessened. Because 90 percent or more of the flowback and produced water must be recycled and reused on site if practicable, fewer truck trips to deliver fresh water and fewer truck trips to haul away wastewater will be needed.

<u>Locations of pads and selection of travel routes</u>. As part of the Comprehensive Gas Development Plan, locations for pads, access roads, and travel routes will be evaluated for noise impacts and public health concerns. Travel routes and times will be planned to avoid periods of heavy public use, school bus routes when children are transported to and from school locations, and to minimize truck travel along residential streets.

<u>Cleaner burning fuel and engines</u>. All on-road and non-road vehicles and equipment using diesel fuel must use Ultra-Low Sulfur Diesel fuel (maximum sulfur content of 15 ppm). All trucks used to transport fresh water or flowback or produced water must meet EPA Heavy Duty Engine Standards for 2004 to 2006 engine model years, which include a combined NOx and NMHC (non-methane hydrocarbon) emission standard of 2.5 g/bhp-hr.

<u>Standards for new road construction</u>. The BMPs require that the design, construction and maintenance of unpaved roads be at least as protective of the environment as the guidelines adopted by the Pennsylvania Department of Conservation and Natural Resources, Bureau of Forestry, for roads in leased State forest land (PA DCNR, 2013). This includes modifying road elevation to restore drainage, sufficient compacting and top dressing, geotextiles where required, dust control, and prompt stabilization of disturbed areas to prevent erosion, among other specifications (PA DCNR, 2011).

<u>Road use and maintenance agreements</u>. The travel routes will be identified during the CGDP process and incorporated into the drilling permit for each well. As a condition of the drilling permit, an applicant shall be required to enter into an agreement with the county and/or municipality to restore the roads which it makes use of to the same or better condition the roadways had prior to the commencement of the applicant's operations, and to maintain the roadways in a good state of repair during the applicant's operations. The agreement may mandate that the applicant post bond.

Conclusion

The impact of increased truck traffic can be minimized but not eliminated entirely. Road damage can be prevented if roads are improved before the heavy truck traffic begins. Local governments, through Road Use and Maintenance Agreements, can hold companies responsible for road damage they cause. The rate of traffic accidents does not have to increase as the volume of traffic increases, but it will rise if drivers of passenger vehicles and heavy trucks do not obey traffic laws and pay attention. It is inevitable that some people will experience traffic noise levels that they find objectionable and traffic delays that they find irritating and inconvenient. These events will be episodic, but in the most extreme cases could last for most of a year. Air pollution may be a problem for those who live very close to highly-traveled routes. The best practices described above will reduce the likelihood of these adverse impacts.

The Departments recommend that additional measures should be taken to reduce the risk further. The most important would be to reduce the number of truck trips. Innovations may provide the key.

In Pennsylvania, some companies are establishing centralized fresh water storage facilities from which water can be delivered to well pads by aboveground flexible hoses, eliminating the need to truck water directly to every well pad. The viability of this practice depends partly on the number and location of well pads and the topography. The feasibility of such a practice should be explored in the Comprehensive Gas Development Plan process and it should be required if it is practicable.

In Colorado, one company has established a centralized facility with all the equipment necessary for preparing and pressurizing the fracturing fluid. The fluid can be delivered by pipes to well pads as far as 4,100 feet from the facility. This would eliminate the need to deliver water, proppant, and additives to the well pad, and do away with the pumper trucks that otherwise are needed at the well pad.

Alternatives to using water for hydraulic fracturing should be required if they are proven to be effective and have less impact. Substitutes such as carbon dioxide and solid rocket propellant have been proposed.

Enforcement of vehicle laws is essential. The State Police have agreed to perform random checks of commercial motor vehicles for compliance with weight and safety regulations if Marcellus Shale development occurs in Maryland. The Maryland Motor Vehicle Administration has adopted sound level limits for vehicles. Maryland Code, Transportation Article, Title 22, Subtitle 6; COMAR 11.14.07.08. These limits are enforced by the State Police and could be checked at the same time.

Lastly, an outreach program to drivers of passenger vehicles and commercial vehicles should be undertaken to educate the drivers of the challenges of sharing the roads.

K. Community Impacts

Background

As part of the Marcellus Shale Safe Drilling Initiative led by MDE and DNR, RESI of Towson University was tasked with examining several of the potential impact areas associated with Marcellus Shale drilling in Western Maryland. The RESI Impact Analysis of the Marcellus Shale Safe Drilling Initiative was released on September 22, 2014. To analyze the potential community impacts of Marcellus Shale drilling in Maryland, RESI conducted a thorough review of relevant literature, engaged with and surveyed stakeholders, and performed a spatial and qualitative analysis of relevant data. RESI's discussions with community members and local representatives revealed several major areas of concern:

- Agriculture,
- Education and schools,
- Public health and safety,
- Environmental protection,
- Housing availability and values,
- Infrastructure and investment,
- Economic and fiscal sustainability, and
- Property rights. (RESI, 2014)

Some of the topics listed above may cause impacts to the community and they are covered in detail in other sections of this report. This section of the report will summarize RESI's findings on potential community impacts that are difficult to quantify, as well as, potential community impacts to agriculture, education and schools and public health and safety.

Data and Discussion

The following subsections summarize potential community impacts that the RESI Impact Analysis of the Marcellus Shale Safe Drilling Initiative found are of concern to stakeholders in Western Maryland but are difficult to quantify or end up undervalued within an economic impact analysis.

<u>Industrialization</u>. Rapid industrialization and the jobs that come with it can lead to rapid population growth that strains public services and disconnects long-term residents from their communities. During a boom cycle, local investment leads to high annual economic growth rates in once sparsely populated rural towns. The capacity for small, rural communities to handle rapid industrialization is limited, and problems arise as communities strain already limited resources in response to increased demand on local infrastructure and services. The potential benefits of rapid industrialization may be great, but communities with little knowledge of or ability to prepare for rapid industrialization may not fully capture these benefits.

Following rapid industrialization, any benefits successfully captured within the community may not be distributed evenly amongst residents. This will create winners and losers. If Marcellus Shale gas development moves forward, an imbalanced distribution of benefits amongst residents can corrode the community, or divide the community by perceived winners and losers. (RESI, 2014, p. 101).

<u>Disruption</u>. The Boomtown Impact Model associates rapid population growth and rapid energy development with increases in stress, changes in individuals' interactions within the community, decreased community cohesion, and poor community character; all of these changes are a disruption to the community. When a resident can quickly identify the type of place in which he or she lives (a farm town, a resort town, etc.), what his or her role in that place is (a farmer, business owner, or community leader), and what his or her relationship is to others (a friend, partner, or employer), then that resident

is strongly tied to his or her community. Formerly strong ties to the community are hard to repair when those roles and relationships are disrupted by an imbalance of benefits and costs throughout the community.

RESI's engagement with local stakeholders and residents indicate strong ties to agriculture, tourism, construction, and existing energy activities. Based on feedback during the stakeholder engagement process, Western Maryland residents appear very clear on their roles in the community. However, the stress of potential changes to the community could impact relationships and trust in political leadership. Stress can lead to increases in social problems (crime, substance abuse, etc.), a lowered standard of living, strained local services, and general disorganization. This tendency is especially true for rural communities. Conversely, urban communities are more able to absorb rapid population growth and industrial development. (RESI, 2014, pp. 102 – 103).

Agriculture. Stakeholders in Western Maryland indicated support from the farming community for responsible natural gas development. Agribusiness and natural gas development currently coexist in Accident, Maryland (in Garrett County), where gas pipelines, storage wells, and a large compressor station are located. Farmers' positive perceptions of drilling in Western Maryland are credited to farmers currently farming around storage wells without significant health or environmental impacts. Stakeholders identified the largest perceived impact to be the stigma of the industry and occasional small leaks. Stigma and negative perceptions, in comparison to environmental and economic impacts of an area, can be difficult to eliminate through policy changes, and interviewees acknowledged that larger wells with greater impacts are anticipated should horizontal drilling occur.

Farmland is often protected from extractive industries, especially surface mining, by conservation easements which serve the purpose of protecting natural ecosystems, recreational areas, and other important open spaces. Different laws regarding conservation easements and split estates complicate farmers' rights to lease property for natural gas drilling. There are conservation groups in support of drilling and conservation groups against drilling on eased land.

Migration of labor from farms to out-of-state well pads can reduce the time spent maintaining local agribusiness. Allowing Marcellus Shale drilling in Maryland could allow these farmers to spend more time on the farm and with their families, while also earning supplemental income working in the natural gas industry or through leasing of mineral rights. Furthermore, stakeholders believe one of two scenarios could occur if drilling is permitted on agricultural land:

1. Lease and royalty payments from shale development would sustain farmers who are otherwise losing money, allowing farmers to sustain their farms after the inevitable "bust" phase of drilling, or

2. Farmers will use the lease and royalty payments to retire from farming, creating a near extinction of agribusiness in Western Maryland, and therefore less economic diversity. (RESI, 2014, pp. 104 – 106).

Schools. Drilling is expected to bring a significant number of jobs into Maryland. As a result, there is the potential for overcrowding of schools if new workers bring young families with them. This possibility is of particular concern for Garrett County, where an education funding deficit in the millions and a decline in the population of school-aged children have led to school closures.

A study from the University of Maryland reported the following data for K-12 schools in Western Maryland as of August 2012: Allegany County Public Schools comprised 22 schools, with renovations for two middle schools and new construction of a high school facility, and Garrett County Public Schools comprised 14 schools, with two middle school closures expected. Garrett County Public Schools ultimately made the decision to close three schools in 2012 (RESI, 2014).

If the population of young families suddenly increases, the remaining facilities may not have the capacity for more students. Stress on teachers and administrators could present both health risks and a potential decline in the quality of education in the area. In addition, increased truck traffic is expected, and raises concerns regarding increases in traffic along school bus routes.

Both counties may need to consider either regulating traffic so that trucks and school buses are on the road during separate hours or assuring that trucks and buses use separate routes. Stakeholders stressed that, in existing conditions, Garrett County graduates a number of bright students from high schools and nearby colleges but does not currently provide the requisite balance of job opportunities for its graduates. Graduates either struggle to find gainful employment within Western Maryland or leave the region. A potential positive impact of allowing drilling in Western Maryland would be an increase in job opportunities for residents. (RESI, 2014, pp. 106 – 108)

Conclusion

The numerous concerns regarding natural gas drilling's impact on Western Maryland's communities can be difficult to quantify. Western Maryland's legal, natural, and political environments are different from those in West Virginia and Pennsylvania and the impact on communities may be different. There are steps that local jurisdictions can take to avoid the possible negative impacts.

L. Industrialization of Landscape

Background

The prevailing landscapes of Garrett and Allegany Counties are dominated by forest cover interspersed with areas of residential, commercial and industrial development concentrated primarily within municipalities (Figure 4, Figure 5). The Maryland Department of Planning classifies the land area of Maryland into 13 distinct types of land use (i.e. low to high density residential, commercial, industrial) or land cover (i.e. agriculture, forest) and has mapped changes in land use/land cover since 1973. (Maryland Department of Planning, Land Use/Land Cover, http://planning.maryland.gov/OurWork/landuse.shtml.) The most current assessment of land use reflects 2010 conditions.

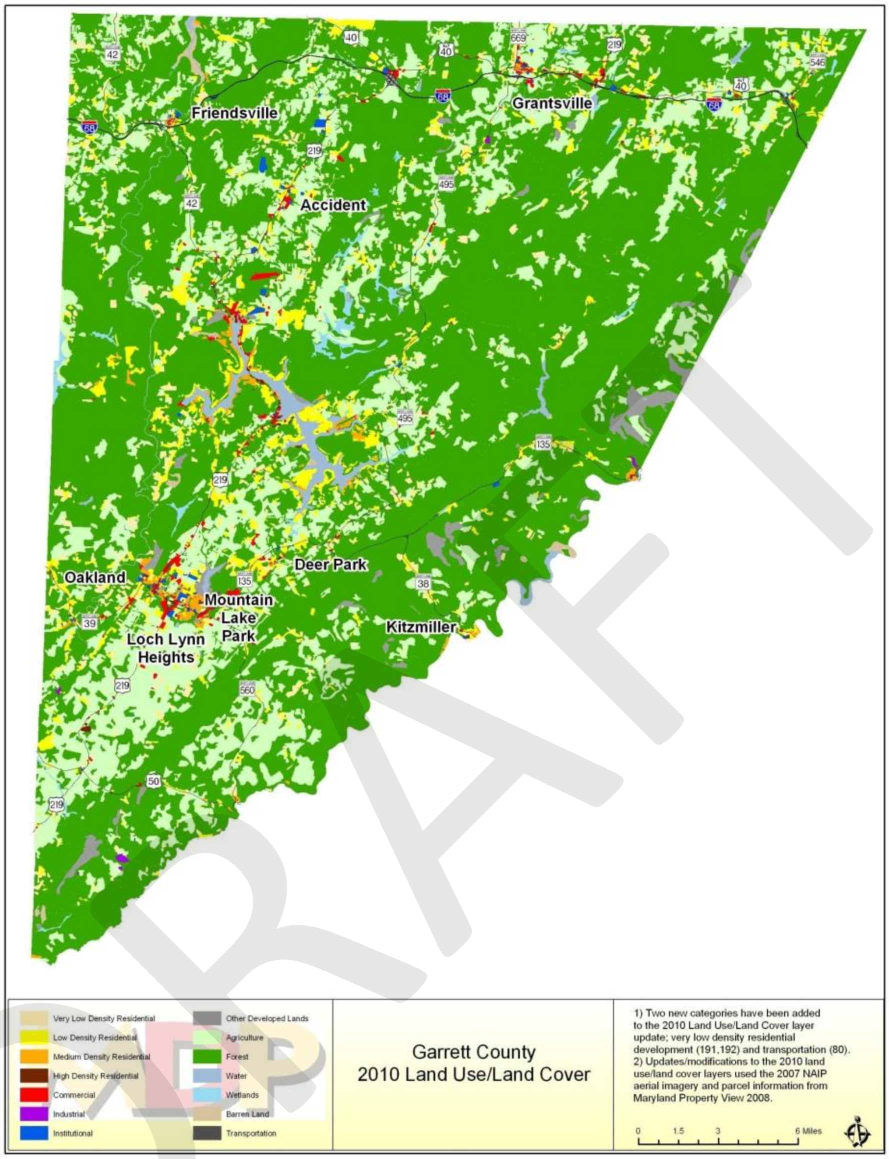

Figure 4. Garrett County 2010 Land Use / Land Cove

In Garrett County, about 20 percent of the land is publicly owned, primarily as state forests and state parks. About 90 percent (377,496 acres) of the land area supports rural resources which are defined as agriculture, forest, extractive/barren/bare and wetlands. Of that area, 75 percent consists of forest land. In Allegany County, 87 percent (230,930 acres) of the land area supports rural resources and, of that, 87 percent exists as forest land.

Recent land use changes in Garrett County since 2002 show an increase in developed land by 4,107 acres with a similar decrease in resource lands; about 78 percent of that as forest and the remainder primarily agricultural land. In Allegany County, developed land increased by 3,386 acres from the loss of resource lands; about 65 percent of that as forest and the remainder primarily agricultural land.

In most cases, new development is occurring adjacent to existing development although there are some instances were new development occurs as pockets within rural resource lands. In Garrett County, most new development is occurring adjacent to existing development although there are some instances were new development occurs as pockets within rural resource lands. In Garrett County, most of the new growth is very low and low density residential development while in Allegany County, new growth is primarily classified as low density residential and other developed lands/institutional/transportation.

As noted in the Garrett County 2008 Master Plan, Garrett County contains the incorporated towns of

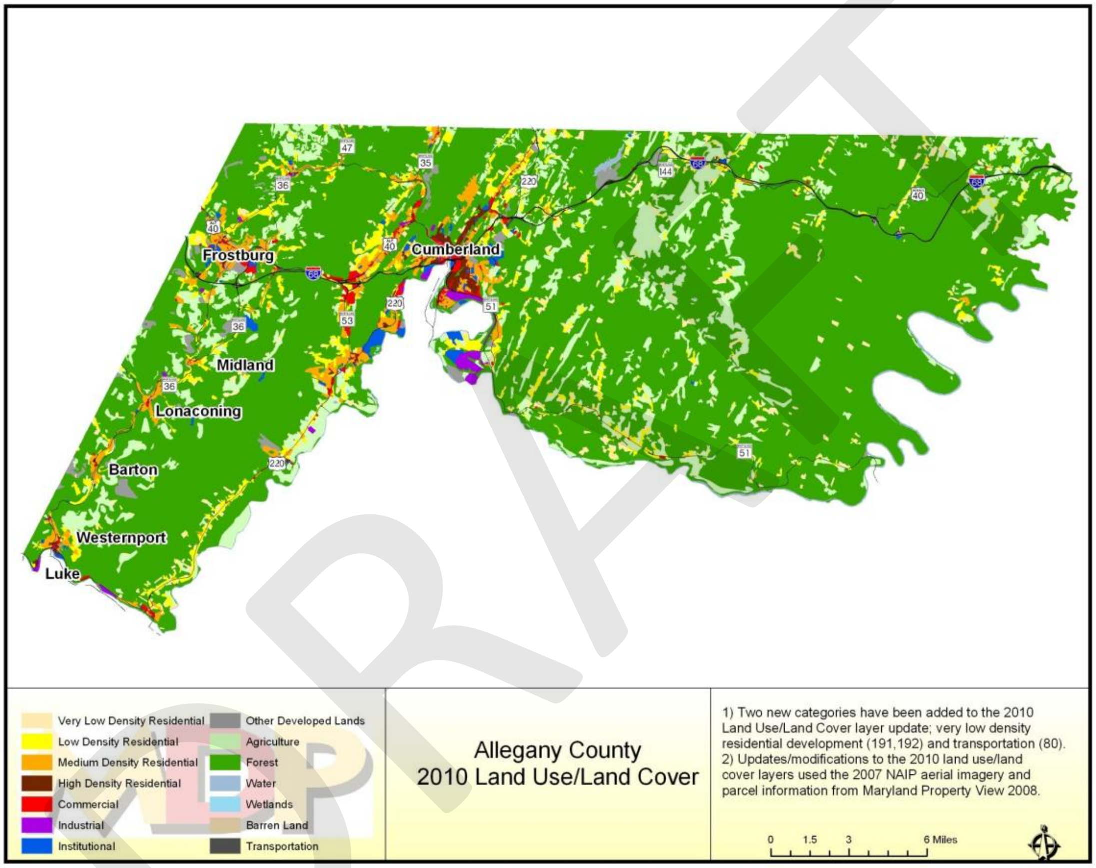

Figure 5. Allegany County 2010 Land Use / Land Cover

Accident, Deer Park, Friendsville, Grantsville, Kitzmiller, Loch Lynn Heights, Mountain Lake Park and Oakland, which is the county seat (Garrett County, 2008). Just over 20 percent of the County's total population lives within these towns. The towns have their own planning authority and adopt their own comprehensive plans and land use regulations. The Comprehensive Plan also recognizes 11 Rural Villages. Formal land use planning in Garrett County began in the 1970s, starting with the Deep Creek Lake area which included regulation of land use within the Deep Creek watershed. Apart from the towns, this is the only part of the county that is subject to land use regulations. The remainder of the county is subject to a subdivision ordinance that controls the subdivision and development of land, but not the use of land.

In Garrett County, zoning controls prohibit the development of oil or gas wells within the 1000 foot buffer surrounding Deep Creek Lake. The town of Mountain Lake Park approved an ordinance in 2011 that bans the creation of new gas wells. The Comprehensive Plan recommends working with the Maryland Department of the Environment, State Highway Administration, other state agencies and energy companies to monitor natural gas development activities to ensure the safety of the ground and surface water supplies, to protect sensitive environmental areas, to address the socioeconomic impacts of natural gas drilling, and to ensure the safety and adequacy of roads to accommodate natural gas drilling activities.

The current Allegany County Comprehensive Plan of 2014 provides for land use planning and zoning for the entire county and is addressed by planning region. Population between 1990 and 2010 has increased in the Greater Cumberland, Greater Frostburg and Middle Potomac planning regions. There are seven incorporated municipalities. Cumberland, Frostburg, Lonaconing and Westernport exercise their planning and zoning authority through comprehensive planning while Barton, Luke and Midland do not. Allegany County's Mineral Resources Element of the Comprehensive Plan promotes exploration of natural gas in the Marcellus shale formation by encouraging policymakers and regulators to engage in the Marcellus Shale Safe Drilling Initiative Advisory Commission. (Allegany County, 2014).

Data and Discussion

Category	**1973**	**2002**	**2010**
Total developed lands (Allegany)	21059	32468	35853
Total resource land (Allegany)	245630	234316	230930
Total land (Allegany)	266689	266784	266783
Total water (Allegany)	2820	2725	2725
Total developed lands (Garrett)	13368	37689	41797
Total resource land (Garrett)	406425	381603	377496
Total land (Garrett)	419293	419293	419293
Total water (Garrett)	5635	5767	5767

Table 10. Land Use in Allegany and Garrett Counties

These data indicate that the percentage of total land developed in Allegany County increased from 1973 to 2010 from 7.9 percent to 13.4 percent and approximately 14,794 acres were developed during that time. The percentage of total land developed in Garrett County increased from 1973 to 2010 from 3.2 percent to 10 percent and approximately 28,429 acres were developed during that time.

Towson University's Regional Economic Studies Institute (RESI), in consultation with the Departments, developed two scenarios of the effects of shale gas development on rural resources. Scenarios 1 and 2 assume 25 percent and 75 percent extraction levels, respectively, of the available Marcellus natural gas resource in Maryland (Table 10. Land Use in Allegany and Garrett Counties). Activity scope and duration associated with each different scenario were evaluated during each shale gas development phase. It is important to note that these scenarios, while plausible, were constructed specifically to mimic the "boom and bust" cycle that is associated with most mineral extraction operations. The actual pace and intensity of development could differ from the scenarios.

Item	Scenario 1	Scenario 2
Extraction Level	25%	75%
Wells per pad	6	6
Average Wells Drilled/Year	15	45
Total Wells Drilled	150	450
Total Number of Well Pads	25	75

Table 11. Well and Well Pad Development Activity for Scenarios 1 and 2

Based upon information from New York (NY DEC, 2011) and information gathered from UGWD applications submitted to the Departments, the land use footprint is assumed to be 15-acres of total site disturbance/land clearing per well pad developed. This estimate includes about 4 acres for the well pad with the remainder needed for roads, pipelines and other supporting infrastructure.

Under scenario 2, the build out predicted for Allegany County is 10 well pads; if each well develops 15 acres, 150 acres would be developed, or 0.06 percent of all the land in the County. Garrett County is larger and less developed than Allegany County. Garrett County is predicted to support 65 well pads under scenario 2. If 65 well pads are constructed, 975 acres would be developed, representing 0.23 percent of land in the County. Therefore, depending on the intensity of shale gas development, a conversion of land to industrial use could range from 375 acres to 1,125 acres. Most of this conversion would be of a temporary nature as site reclamation to pre-shale gas development conditions would be required.

The proposed Comprehensive Gas Development Plan (CGDP) and the recommended location restrictions and setbacks are highly effective for stabilizing significant land use change. The CGDP is an opportunity to apply a broad-scale proactive planning perspective by considering the entire project scope of a company, rather than responding shale gas development on a permit by permit basis. The CGDP requires adherence to the suite of location restrictions and setbacks. According to the Part II: Interim Final Best Practices Report, published in July 2014, these restrictions would remove 83.2 percent (422,998 acres) of the land surface within the Garrett and Allegany County Marcellus shale exploration area from surface development. These restrictions would leave 85,172 acres available for surface operations. If surface area above the Accident Gas Storage Field were also excluded from well pad development due to incompatible uses, the surface constraints increase to 84.7 percent (430,559 acres), leaving 77,510 acres of the exploration available for surface development.

The nature of the restrictions are to focus shale gas development in areas that are primarily composed of farm and forest land and are far removed from population centers and occupied structures. If the most intensive extraction level occurred, resulting in the development of 75 well pads and associated supporting infrastructure, the temporary conversion of largely rural resource land would amount to 0.22 percent over the entire exploration area (508,169 acres) in Garrett and Allegany counties.

Conclusion

The CGDP can further minimize impacts to land use patterns and the rural character of western Maryland by modifying where the land use impacts and how those locations interact with the rural landscape values that epitomizes this area. CGDP planning principles will address viewshed impacts, co-locating linear infrastructure to reduce fragmentation of forested landscapes, and closely evaluating the timing and pattern of transportation needs and road traffic to address concerns faced by rural villages and towns.

In Maryland, county and municipal jurisdictions have local land use authority that can be leveraged to refine where shale gas development occurs and can plan in advance for some anticipated impacts to be better prepared for increased demands for housing, retail and commercial services and community support services. Jurisdictions should evaluate needs at the local level that persist or cannot be addressed by the State’s best practices recommendations.

M. Influx of Workers

Background

The natural gas industry, like most extraction industries, experiences a “boom and bust” cycle. The demand for labor is highest during the active development phase, when wells are being drilled and pipelines are being laid. Some of this labor will likely be met by the existing residential labor force. There will also be an influx of out of state workers to fill the demand during the active development phase.

Data and Discussion

RESI (2014) assessed employment based on no drilling and the 25 percent and 75 percent extraction drilling scenarios over the first 10 years of drilling, assumed to be the “boom” period (2017-2026). RESI expects that, during the “boom” years, the greatest change from the baseline employment will occur in 2021, adding between 1,240 jobs in Scenario 1 and 2,425 jobs in Scenario 2, $148.4 million in economic output in Scenario 1 and $348.6 million in economic output in Scenario 2, and $35.4 million in wages in Scenario 1 to $76.7 million in wages in Scenario 2.

This increased economic activity in the region may incentivize some individuals previously commuting to relocate to the region. RESI found that more than 60 percent of the current workforce used in Pennsylvania or West Virginia drilling operations were from Maryland. Using this assumption, this could indicate that of the new jobs in the region, more than 30 percent will be taken by commuters into the area.

RESI used projected inmigration directly related to growth in employment in the natural gas industry to form a conservative estimate of the resident share of new direct jobs. Based on current commuting patterns in Western Maryland, RESI assumed an estimated 58.9 percent and 61.4 percent of spinoff jobs in Allegany and Garrett Counties, respectively, would be acquired by new residents living and working in each county.

Following peak years of drilling, the influx of new residents peaks in 2021 with 744 new residents in Scenario 1 and 1231 new residents in Scenario 2. Though the total number of households continues to increase over the ten-year period, the presence of drilling in Scenarios 1 and 2 will create a large, transient influx of residents at the early stages of drilling followed by slower year-over-year growth in household population compared to the baseline scenario.

Conclusion

The influx of workers to Garrett and Allegany Counties will be highest during the active development phase. Some of these jobs will be filled by the existing residential labor force of both Counties. Some jobs will be filled by new residents that permanently relocate to the area, while others will be filled by transient out of state workers who do not intend to permanently relocate to the area. The new workers that permanently or temporarily relocate to the area could put pressure on the housing market, local schools, roads and transportation, broader community services and infrastructure, and social services. The Counties are well-positioned to accommodate the additional workers if advance planning occurs.

N. Availability of Housing

Background

The demand for labor and, consequently, housing is highest during the active development phase, when wells are being drilled and pipelines are being laid. While some of this labor may be met by an existing residential labor force, there will be an increase in new workers that will be seeking housing close to their work. Many of these workers will only need temporary housing as they move from job to job. In rural areas, the available housing supply may not be adequate to meet these demands. As a result, highly paid gas industry workers, who can pay higher rents, may use available housing, such as rental units or hotels and displace low income residents or tourists. Both of these effects adversely affect the western Maryland economy and could lead to increase in homelessness for displaced residents.

Data and Discussion

RESI (2014) assessed existing housing, projected populations changes and housing demands based on no drilling and the 25 percent and 75 percent extraction drilling scenarios over the first 10 years of drilling, assumed to be the “boom” period (2017-2026). In the absence of drilling, Allegany County has a small surplus of available (for sale or rent) housing units. Under both extraction scenarios, the county will experience a shortage in available housing by 2019. If unavailable housing is included, which is vacant housing currently not for sale or rent, there will be no shortage under either scenario. In Garrett

County, RESI determined that there would be no housing shortages, in either available or unavailable housing, whether drilling occurred or not. However, this assessment did not account for the Deep Creek Lake second-home and vacation rental market. When housing units in the Deep Creek Lake area were excluded from the analysis, housing shortages were apparent. With or without drilling activity, Garrett County will have a total housing shortage, which includes both available and unavailable housing. Shortages of available housing are immediate and exist for all ten years. Under no drilling, total housing shortages would occur in 2022. Under both extraction scenarios, total housing shortages are probable in 2020.

A typical natural gas industry employee earns roughly $40,000 more in household wages than about half of western Maryland residents. This raises concerns that potential increases in rental rate will displace local residents with lower income. Residents with short-term leases and lower income are the most at risk. In areas of intense drilling, higher rental rates and displacement of residents can lead to increases in homelessness leading to higher demand for foster care services, increases in school dropout rates, and eventually higher demand for public assistance. RESI suggests that if the influx of workers is relatively short-term, renters may not be impacted if long-term leases are held, month-to-month leases or daily rates for temporary housing, such as hotel rooms, would be more vulnerable to rising rates. A review of the effects of Marcellus Shale gas extraction on housing in Pennsylvania notes that landlords in small communities with supplies of housing similar to Allegany and Garrett Counties preferred renting to long-term residents and rental rates rather than dealing with the cost and effort of finding new tenants among a transient, high-turnover workforce. If rents were increased at all, they were only raised by 5 to 10 percent. (Williamson & Kolb, 2011).

RESI (2014) suggests that rental ordinances and exclusionary zoning ordinance could assist in the management of severe changes in housing needs. New construction is a short-sighted solution which could result in long-term blight through an excess of vacant and poorly maintained housing stock once the gas industry workforce leaves the area. Housing needs can be addressed by repurposing existing structures. For example, Garrett County has at least three closed schools with potential to be converted into housing.

Conclusion

Allegany County has adequate housing supplies to meet increased demands from unconventional gas well development. Garrett County may face housing shortages under the assumption that housing units in the Deep Creek Lake will not be available for an influx of gas industry workers. This shortage is anticipated even if drilling does not occur. While Garrett County may elect to build new housing, they are cautioned to not over extend county resources and plan for accommodating a temporary workforce while protecting housing supply for existing residents and the tourism industry.

O. Economic Impact: Gas Production

Background

Gas development and production will bring economic benefits to the region in terms of jobs, wages and tax income. As noted in the MIAEH (2014) health report, an improved economy and jobs for local residents can provide benefits for the community and for health care. "Revenue flows from the extraction of natural resources, when distributed in an effective and equitable manner, can fund public services such as healthcare infrastructure; the potential increase in workers with health insurance can also have a positive impact on local health care industry." (Citation omitted)

Data and Discussion

In the economic study, RESI (2014) used a dynamic input/output model, a willingness to pay model, and a hedonic pricing model to estimate the impacts. RESI modeled baseline (no drilling), extraction of 25 percent of the available gas, and extraction of 75 percent of the gas over a 20 year period. In each case, all the wells were drilled in the first ten years to mimic the cyclical nature of most extractive industries. Royalty payments go to the owner/lessor of the mineral rights. Because mineral rights are often separated from the surface rights, and there was no way to determine if royalty payments would add to the household income of residents, in its model, RESI included royalty payments as an increased production cost, but not as increased disposable income to households. The total royalty payments were calculated, however.

Reproduced here are the summary charts from the RESI report:

Impact	Total at Peak	Annually, 2017-2026	Annually, 2027-2036
Employment	492	224	9
Wages	$12.6 million	$5.9 million	-$0.6 million
Output	$49.7 million	$25.5 million	$1.8 million
Tax revenues	$0.9 million	$0.4 million	$0.1 million
Severance tax revenues	$1.0 million	$0.6 million	$6,624

Table 12. Economic and Fiscal Impacts for Allegany County – Scenario 1, 25% extraction
Source, RESI, 2014 Figure 1

Impact	Total at Peak	Annually, 2017-2026	Annually, 2027-2036
Employment	908	682	67
Wages	$26.4 million	$18.7 million	-$0.9 million
Output	$101.8 million	$76.3 million	$9.2 million
Tax revenues	$1.8 million	$1.3 million	$0.4 million
Severance tax revenues	$2.3 million	$2.0 million	$68,645

Table 13. Economic and Fiscal Impacts for Allegany County – Scenario 2, 75% Extraction
Source, RESI, 2014 Figure 2

Impact	Total at Peak	Annually, 2017-2026	Annually, 2027-2036
Employment	1,240	1,018	136
Wages	$35.4 million	$29.7 million	$0.5 million
Output	$148.4 million	$122.4 million	$16.2 million
Tax revenues	$2.5 million	$1.9 million	$0.6 million
Severance tax revenues	$4.2 million	$3.5 million	$0.3 million

Table 14. Economic and Fiscal Impacts for Garrett County – Scenario 1, 25% Extraction
Source, RESI, 2014Figure 3

Impact	Total at Peak	Annually, 2017-2026	Annually, 2027-2036
Employment	2,425	1,848	-44
Wages	$76.7 million	$60.6 million	-$3.5 million
Output	$348.6 million	$264.0 million	$12.5 million
Tax revenues	$3.6 million	$2.9 million	$0.3 million
Severance tax revenues	$13.5 million	$9.9 million	$0.6 million

Table 15. Economic and Fiscal Impacts for Garrett County – Scenario 2, 75% Extraction
Source, RESI, 2014 Figure 4

Royalty payments will benefit the owners and lessors of the mineral rights, who may or may not reside in Maryland. The royalties paid out are shown in Table 16. Estimated Royalty Payments Made by Firms Extracting Gas in Allegany CountyTable 16 (Allegany County) and Table 17 (Garrett County).

Year	Scenario 1	Scenario 2
2017	$573,500	$1,720,501
2018	$1,161,024	$4,403,774
2019	$1,433,345	$4,668,713
2020	$1,710,135	$4,183,495
2021	$1,710,135	$4,183,495
2022	$1,838,985	$4,057,007
2023	$1,216,533	$4,090,765
2024	$599,171	$4,124,016
2025	$320,939	$2,644,684
2026	$179,353	$1,317,217
2027	$98,997	$701,536
2028	$54,296	$382,648
2029	$28,565	$208,304
2030	$14,113	$113,545
2031	$5,948	$59,610
2032	$1,260	$29,428
2033	$0	$12,413
2034	$0	$2,704
2035	$0	$0
2036	$0	$0

Table 16. Estimated Royalty Payments Made by Firms Extracting Gas in Allegany County

Year	Scenario 1	Scenario 2
2017	$1,720,501	$8,602,507
2018	$4,710,674	$22,018,869
2019	$10,127,485	$26,168,444
2020	$10,351,518	$26,876,035
2021	$9,638,948	$30,759,793
2022	$8,734,644	$26,767,166
2023	$8,150,687	$23,639,728
2024	$8,285,283	$22,325,666
2025	$8,337,173	$23,218,113
2026	$6,206,058	$15,442,431
2027	$2,963,094	$7,515,478
2028	$1,587,204	$4,026,382
2029	$853,849	$2,180,602
2030	$466,148	$1,192,496
2031	$254,143	$638,059
2032	$134,945	$334,699
2033	$68,738	$168,545
2034	$30,870	$75,261
2035	$8,488	$16,977
2036	$0	$0

Table 17. Estimated Royalty Payments Made by Firms Extracting Gas in Garrett County
Sources: EIA; RESI, 2014

If the recipients of royalty payments reside in Allegany or Garrett Counties, the impact on individual households could be substantial. RESI postulates two extreme outcomes for farmers: lease and royalty payments from shale development would sustain farmers who are otherwise losing money, allowing farmers to sustain their farms after the inevitable “bust” phase of drilling; or farmers will use the lease and royalty payments to retire from farming, creating less agribusiness in Western Maryland, and therefore less economic diversity.

Allegany County, having a larger number of jobs and a fewer number of potential sites for gas wells, experiences modest job growth during the boom years and declines to near baseline (although still above baseline) at the end of the 20 year period. Figure 6. Garrett County, on the other hand, experiences a more dramatic increase in employment during the boom years, but under Scenario 2 actually has lower employment during the bust cycle. Figure 7. The boom and bust cycle shown here is a product of the scenarios, but it is not atypical of resource based industries. If the pace of development were slower, the changes would be more gradual, but the tax revenue to the Counties does not last. Reliance on these revenues could leave the Counties in a difficult budgetary position when gas production is over.

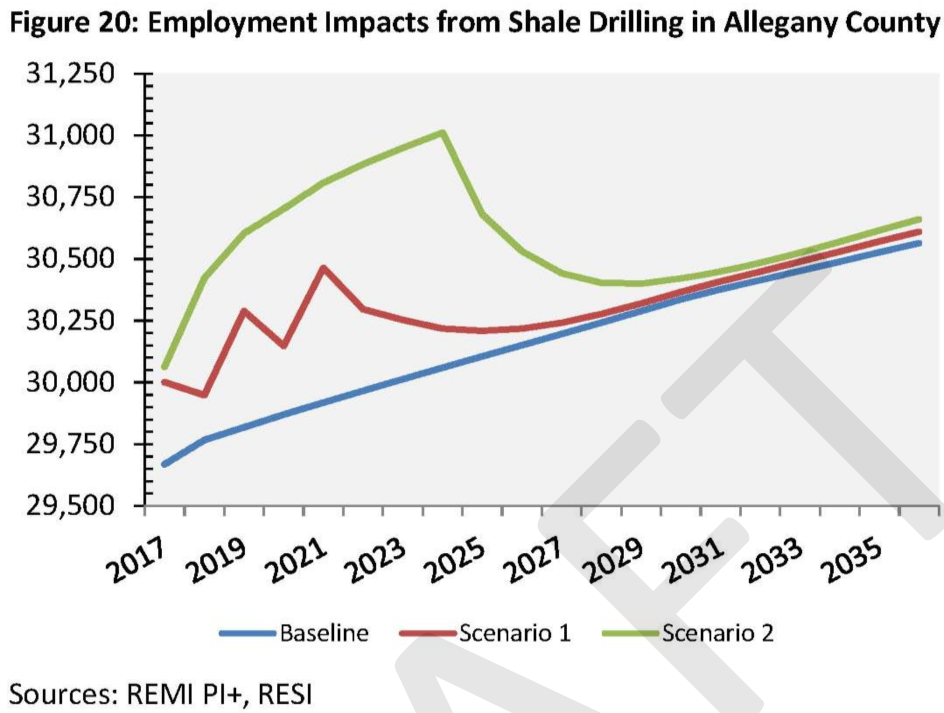

Figure 6. Employment Impacts in Allegany County

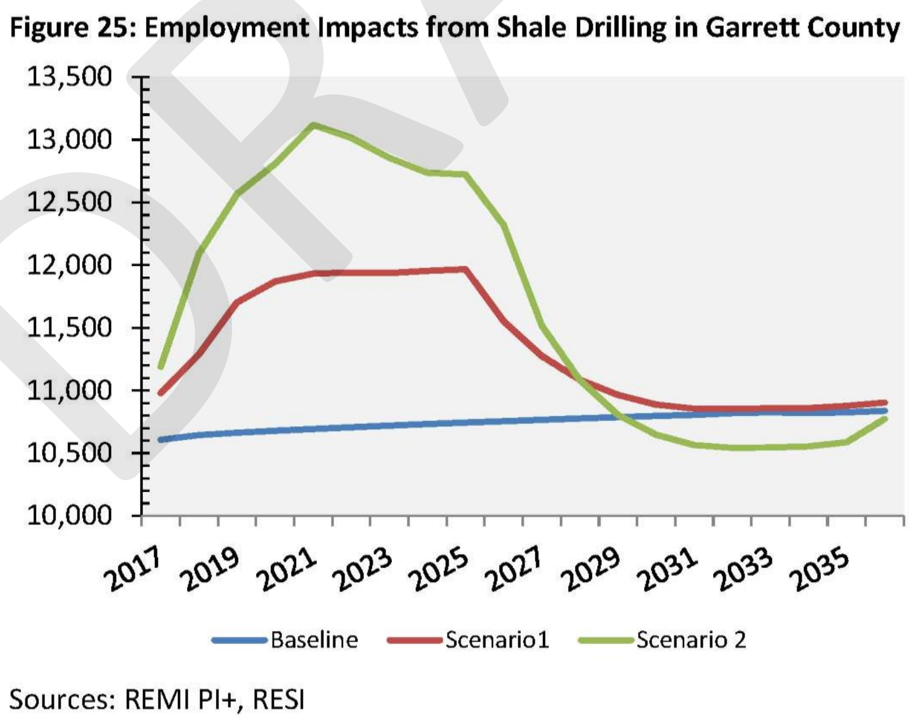

Figure 7. Employment Impacts in Garrett County

Conclusion

Gas development could bring significant income and economic growth to Western Maryland until the gas is fully extracted. Local governments should be mindful of the danger of relying on resource extraction instead of diversifying their economies.

P. Economic Impact: Property Values

Background

Data show that property values are impacted by drilling activity, particularly as one gets closer to the drilling activity. There can be an increase in property values for properties not in very close proximity to a well but in the general vicinity of a well. However, there can be a significant drop in property values near active well sites, and it can persist for decades.

Data and Discussion

RESI (2014) analyzed proximity to operational wells and determined that the closer the wells are to residential areas, the lower those property values will be. The decline in home values may impact resale values for homeowners as well as their tax payments over time.

A 2012 study by Muehlenbachs, Spiller, and Timmins found home values for homes located in Washington County, Pennsylvania near well sites and reliant on well water declined by 26.6 percent. In a 2013 study, the same authors analyzed property transactions from 36 counties in Pennsylvania and 7 counties in New York. (Muehlenbachs, Spiller, & Timmins, 2013). Similar to the findings from their study of Washington County, their findings indicated that properties relying on private drinking water wells were negatively affected by nearby shale gas wells whereas those properties that had access to public water were positively affected. However, the negative effect for groundwater dependent homes became greater the closer the well, and the positive effect for public water homes became smaller. For properties not in very close proximity to a well but in the general vicinity of a well (i.e., within 12 miles), property values are seen to increase.

Additionally, according to RESI's model for housing in the region, the existing vertical gas wells in the Garrett and Allegany County area have depressed the value of properties within a half-mile of a well by 7 to 9 percent relative to a comparable home more than two miles away. This analysis was done over time, indicating that wells within the region have some underlying impact on people's perception of a home. Despite the wells being drilled in some cases more than 50 years prior, the environmental and health concerns may still affect an individuals' decision when purchasing a home.

Drilling for, producing and storing gas are permitted by right in all zoning districts governed by the Deep Creek Watershed Zoning Ordinance, subject to State and federal regulations and the following setbacks: 2,000 feet from the high water elevation of Deep Creek Lake; and 1,000 feet from the property line of any lot not owned or leased to the entity responsible for the gas drilling, producing or storage operation. Unless the zoning ordinance is amended, there is a risk of significant loss in tax revenue to the County. The lack of zoning in areas outside of the Deep Creek Lake area is suspected to have impacted property values in Garrett County, and a lack of regulation on land use could be increasingly detrimental with the presence of increased industrial activity.

A decline in property valuation has a significant impact on resale value as well as fiscal revenues. The local share of property taxes begins to demonstrate the impact of the property value decline by 2032. Revenues by 2032 in Garrett County begin to fall below baseline projections. The fall in property tax revenues is a direct result of the decline in the property values associated with those homes within a half-to one-mile of natural gas wells.

Conclusion

Drilling activity clearly has an impact on property values. This impact generally is negative, and results in a drop in property values. This impact is felt the most strongly for properties nearest active well sites. This can negatively affect resale values and property taxes, and can persist for many decades after drilling stops.

Q. Economic impact: Tourism

Background

The foundation of western Maryland's tourism economy is grounded in the rural resource and natural beauty that attracts visitors to this region for outdoor recreational pursuits and its second-home market, particularly in the Deep Creek Lake area. In Garrett County, a majority of sales tax revenue is generated by tourism and is heavily influenced by resort, recreation, amusement and outdoor sports attractions. There is great concern that impacts from poorly managed unconventional gas well development could adversely affect scenic viewsheds, wildlife, water quality, open space and the other natural resource amenities that bring visitors to this region to hike, fish, hunt, boat and vacation. Bad press from accidents or leaks could dampen tourism. Potential visitors may choose to go elsewhere if they perceive their experience may be impacted by environmental degradation. The natural gas industry could limit access to tourism destinations through increased traffic or road damage and reduced lodging capacity. In addition to these losses in revenue, tourism and recreation business owners could also be affected by a reduction in available labor or reduced access to land and water destinations.

Data and Discussion

The economies of Allegany and Garrett Counties have unique attributes in that each has a few set of industries that employ the majority of area residents. In Allegany County, the top five industries are Health Care and Social Assistance, Retail Trade, Accommodation and Food Services, Manufacturing, and Administrative and Waste Services. Garrett County's top five industries are more reliant on tourism and include Retail Trade, Accommodation and Food Services, Manufacturing, Construction, and Arts and Entertainment.

RESI evaluated existing studies and data from regions undergoing active shale gas extraction and found that tourism-related impacts are less well documented than other economic and community impacts. In part, this was due to a lack of available, uniform data on hotel tax revenues, industry-level employment and other key indicators needed to evaluate effects of the gas industry on tourism. For example, occupancy rates did not differentiate between "visitors" who were tourists and "visitors" who were employed at drill sites. In addition, RESI noted that other economic factors, such as the housing recession and presence of other extractive industries that might also impact tourism, were difficult to separate out from those associated with the shale gas extraction industry.

RESI's research identified some qualitative impacts associated with unconventional gas well development. Businesses affected by tourism, either directly or indirectly, will be drawing from the same resources; labor, water and land, that the gas industry relies on. Businesses may be faced with needing to increase wages in order to compete with the higher salaries offered by the gas industry. Hotel and other lodging capacity may be reduced for tourism if alternative housing cannot be identified for the transient gas industry workforce. Traffic and road damage may reduce visitors' access or interest in traveling to western Maryland. Because nonresidents and second-home owners have more flexibility in where they choose to vacation, the perceptions of adverse impacts to environmental quality and tourism based services are highly influential. While there may be an economic downturn in the tourism industry, this could be offset by an upswing of increased hotel taxes. Local governments should evaluate existing hotel and amusement tax policies to fully capture the expenditures of a transient workforce and to sustain the entire tourism industry in the long term. RESI also suggested implementing a conservation fund to mitigate impacts and maintain aesthetic qualities. Residents demonstrated a willingness to pay $16/year to support this goal.

The Interim Final Best Practices report (MDE and DNR, 2014a) provides the careful planning and regulatory framework needed to minimize the impacts of unconventional gas well development that could adversely affect the tourism economy. Maintaining the rural character of western Maryland's landscape, particularly as visitors enjoy scenic vistas as they travel to and around the region is critical. The greatest visual impacts are temporary, spanning the period of construction of the pad and road to production phase. Lights and flares will be visible at night. Once the well is in production, the visual impact is less, although there may be pipeline rights of way that could bisect forested landscapes. While mainly temporary, these impacts are addressed through a range of visual mitigation measures that include viewshed analysis for siting decisions, visual barrier and camouflage techniques, management of night lighting and controls on flaring. The CGDP requires transportation planning to avoid heavy truck traffic during times of high tourism activity. The CGDP, location restrictions and setback, engineering design standards and controls, water and waste management requirements, site reclamation and closure, among other best practices serve to prevent to the greatest extent possible the types of impacts to communities, environment, natural resources and public health that could dampen the interests of potential tourists.

Conclusion

Due to a lack of data regarding the coexistence of tourism and drilling, the possible impacts to tourism activity in western Maryland were not quantifiable. Nor was it feasible to separate out the effect on tourism of other factors, such as the recent national recession or the effect of other extractive industries, from the effect of the unconventional shale gas development industry. Perceived decline in environmental amenities and access to tourism related services such as destinations and lodging is of great concern to the businesses and residents of Western Maryland. Careful planning, regulatory control and management of unconventional gas well development are key to maintaining the tourism industry.

R. Emergency Response Capacity

Background

Information about traffic accidents and incidents at well pads in other states indicates that additional burdens fall on emergency response personnel when unconventional natural gas development occurs in a region. Concern has been expressed about the ability of Western Maryland communities to manage the additional demands.

Data and Discussion

The following information about Allegany County's fire and emergency response capability appears on the webpage for the County's Department of Emergency Services at http://gov.allconet.org/DES/Fire_Ambulance_Companies.htm:

> Allegany County is served by 13 volunteer ambulance companies and one career ambulance service. Advanced life support is provided by 13 of the 14 ambulance companies and basic life support is provided by the remaining one. There are also two commercial ambulance companies serving Allegany County. The Maryland State Police medical helicopter, Trooper 5, is stationed at the Cumberland Regional Airport in nearby Wiley Ford, West Virginia and provides advanced life support.
>
> The area is served by the Western Maryland Regional Medical Center, the designated area wide trauma center, 12500 Willowbrook Road, Cumberland.
>
> Emergency personnel receive training provided by the Maryland Fire and Rescue Institute and the Regional Emergency Medical Services Council. Personnel are certified through the Maryland Institute for Emergency Medical Services System.

The following additional information is provided in the Allegany County Hazard Mitigation Plan Update (2012), available online at http://gov.allconet.org/DES/docs/Allegany%20County%202012%20Hazard%20Mitigation%20Plan%20Update.pdf. The municipal and non-municipal fire companies and rescue squads are staffed by volunteers, except for Cumberland, which has a paid fire department. The County has established a Special Operations Team to assist local fire and rescue organizations; this team has training in hazardous materials incident response, swiftwater search and rescue, collapse rescue, high-angle rescue, confined space rescue and search and rescue. The County's 2008 Allegany County, Maryland Hazardous Materials Emergency Response Plan details the procedures to be utilized during a hazardous materials incident. The County has a HazMat Team that can be called to respond to incidents.

Garrett County's webpage provides the following information about emergency management at http://www.garrettcounty.org/emergency-services:

> Garrett County Emergency Management develops and maintains plans for emergency response, including the County Emergency Operations Plan, Hazard Mitigation, Hazardous Materials Response Plan. Responsible for coordinating evacuation and sheltering of populations affected by disaster. Coordinates with other public safety response entities to ensure a timely and appropriate response to any and all emergencies.
>
> July 13, 2011 Garrett County's 911 center consolidated with the Garrett County Sheriff's Office, which placed the 911 communications officers for fire rescue and EMS with the law enforcement communications officers in one brand new center. This move involved training and certification for all communications officers in Emergency Medical Dispatch and Emergency Police Dispatch, which enabled the communications officers to work more efficiently in all circumstances.
>
> 911 Public Safety Answering Point / Police, Fire & Rescue Communications receives and processes all emergency 9-1-1 calls for assistance, including fire, EMS, and police. Once sufficient information has been gathered, the call-taker must alert the appropriate response agencies, maintain communications, and log all pertinent information. Additionally, all staff must maintain nationally certified Emergency Medical Dispatch training which provides emergency medical instructions to callers, as well as Emergency Police Dispatch training.

The web page also identifies five trained emergency medical services providers who are associated with the local fire departments and rescue squads. The County is currently revising its Hazard Materials Plan, which specifically assigns roles and responsibilities of all agencies and departments involved in a hazardous materials accident, whether it is from a fixed facility or as a result of a transportation accident. The County has a Local Emergency Planning Committee, which is responsible for development and oversight of the plan. This committee is made up of individuals representing response agencies, business and private citizen leaders.

With the exception of fires on the well pad and well blowouts, incidents involving the oil and gas industry are not significantly different from other accidents and hazardous materials incidents. Even an accident involving a worker injury high on a drill rig – a high-angle rescue – has been the subject of training of the local emergency response personnel.

Fires and blowouts at the well pad require specialized training, and local emergency response personnel would be expected only to remove the injured, establish a perimeter, and perhaps assist with an evacuation, if it were deemed necessary. Nevertheless, such incidents would likely require the presence of police or emergency response personnel for an extended period of time. These incidents, if they cannot be managed by the workers on site, require specialized contractors that are on call by the oil and gas industry. The State will require that the operator shall identify specially trained and equipped personnel who could respond to a well blowout, fire, or other incident that personnel at the site cannot manage. These specially trained and equipped personnel must be capable of arriving at the site within 24 hours of the incident.

The topic of emergency response was discussed at the Advisory Commission meeting of March 10, 2014. Thomas Levering, Director of MDE's Office of Emergency Preparedness and Planning, and John Frank, Director of Garrett County Emergency Services, were present and discussed the ongoing activities to plan for gas development and the need for training and equipment.

Conclusion
Emergency response presents a challenge because volunteers staff most of those services in Allegany and Garrett Counties, and because of the lack of a dedicated funding source. The Departments' Best Management Practices Report requires that: "Operators shall, prior to commencement of drilling, develop and implement an emergency response plan, establish a way of informing local water companies promptly in the event of spills or releases, and work with the governing body of the local jurisdiction in which the well is located to verify that local responders have appropriate equipment and training to respond to an emergency at a well." This requirement will ensure that the well operators will support local authorities to ensure emergency response resources are in place to protect the workers and the public.

S. Health Infrastructure Capacity

Background
Considerable concern has been expressed about the impact of the arrival of many additional gasfield workers on the public health infrastructure. Newspaper articles and internet sources have reported that levels of crime, sexually transmitted infections (STIs), mental illness and substance abuse have risen in areas where there was a large influx of workers into rural areas. Similar sources have reported that hospitals have difficulty dealing with the number of emergency room visits and suffer financially because many of the transient workers lack health insurance.

Data and Discussion
Garrett County and part of Allegany County have been recognized to be medically underserved areas. MIAEH (2014) reported that "Allegany County is a designated Health Professional Shortage Area (HPSA) for primary care for low-income populations, mental health care for Medical Assistance populations, and dental care for Medical Assistance populations. Allegany County has a critical need for specialty providers including vascular surgery, urology, as well as dentists willing to provide care for adults with no insurance or Medical Assistance. Garrett County is a designated HPSA for primary and mental health care, and dental care for Medical Assistance populations."

According to the University of Maryland School of Public Health (MIAEH, 2014), "A handful of studies that have been conducted indicate that extractive industry workers place similar demands on health care infrastructure as local residents, with an increased demand on emergency department services." (Citations omitted.) Their study, however, did not quantify the increased demand, other than to compare the number of new workers to the existing permanent population. No mention was made of the large number of vacationers who come to the Garrett County area during the summer and the ski season.

To estimate the burden on emergency, urgent care, and trauma care, one can refer to statistics supplied by the United States Government through the Centers for Disease Control and Prevention (CDC) and National Institute for Occupational Health and Safety. The annual occupational fatality rate for oil and gas workers has historically been higher than those for workers generally. The CDC reported the averages for the period 2003-2009 as follows:

Category	Fatalities per 100,000 full time workers
Oil and Gas Workers	27.5
All US Workers	3.9

Table 18. Annual occupational fatality rate
Source: CDC, 2012.

The leading causes of deaths for oil and gas workers included highway motor vehicle crashes (29 percent); workers being struck by tools or equipment (20 percent); explosions (8 percent), workers caught or compressed in moving machinery or tools (7 percent), and falls to lower levels (6 percent). (CDC, 2012).

In contrast, the non-fatal injury rate has been lower than the United States average.

Category	Non-fatal injuries per 100 full time workers
All oil and gas job extraction	1.2
Oil and gas support activities	1.9
Oil and gas drilling	3.3
All US workers	3.5

Table 19. Annual nonfatal injuries rate
Source: CDC, 2012

The Regional Economic Studies Institute at Towson University, in an evaluation of the economic impact of Marcellus Shale gas development, considered two potential development scenarios of different intensities (RESI, 2014). For each scenario, the number of direct jobs in the oil and gas industry and the number of "spinoff" jobs were projected for Allegany County and Garrett County. The peak year for Garrett County is 2021 and the peak year for Allegany County is 2024.

County	Peak year for jobs	Direct jobs	Spinoff jobs
Allegany	2024	442.5	465.5
Garrett	2021	1185	1239.7

Table 20. Numbers of jobs in peak year
Source: Revised RESI study, Figures 97 and 108

Applying the fatality rate of 27.5 per 100,000 workers to oil and gas workers and the rate of 3.9 per 100,000 workers in spinoff jobs yields the following projection for the peak year:

County	Fatalities (direct jobs, peak year)	Fatalities (spinoff jobs, peak year)
Allegany	0.12	0.02
Garrett	0.33	0.05

Table 21. Number of fatalities in peak year

Because the number of jobs in each category (all oil and gas extraction, oil and gas support activities, oil and gas drilling) is not known, for purposes of estimating the number of nonfatal injuries, the highest rate, 3.3 per 100 full time workers, will be applied to the direct jobs. The spinoff jobs are assigned the rate for all United States workers.

County	Injuries (direct jobs, peak year)	Injuries (spinoff jobs, peak year)
Allegany	14.6	16.3
Garrett	39.1	43.4

Table 22. Number of nonfatal injuries in peak year

In the peak year, assuming all the direct and spinoff jobs were filled by workers moving in from out of County, the number of direct and spinoff jobs for Allegany County would represent an increase of 1.2 percent over the 2010 census population of 75,087. For Garrett County, the number of workers in the peak year, assuming all the jobs were filled by persons moving into Garrett County from elsewhere, would represent an increase of 8.1 percent over the 2010 census population of 30,097. Garrett County, however, experiences an influx of non-residents throughout the year. The number of person-trips was estimated in a tourism study as exceeding 1.1 million person-trips from August 2008 to July 2009 (Deng et al., 2010):

> Seasonal person-trips are estimated at 402,388 for summer, the largest of all seasons, accounting for 36.0% of total person-trips for the survey year. Winter season was also popular with the total person-trips being 310,733, followed by fall (240,315 person-trips) while spring season was the least attractive with the total person-trips being 164,308.

On September 25, 2014, Rodney B. Glotfelty, Garrett County health Officer, provided written testimony to the Garrett County Marcellus Shale Advisory Committee on the MIAEH report. Mr. Glotfelty did not agree with the conclusions drawn by the authors of the study, who predicted that "an increase in health care utilization, regardless of whether workers are insured or uninsured, would strain the existing healthcare infrastructure, likely leading to decreased quality, availability, and access to services" (MIAEH, 2014). He wrote:

> While our health system may be challenged in serving an influx of relatively young people working in the gas development industry, in general we feel it is resilient enough to meet the increased demand without jeopardizing public health. In late fall or early winter, a new satellite office of Mountain Laurel Medical Center (FQHC) will be opening in Grantsville. This means additional providers will be recruited to serve Garrett County residents. The new CEO of the hospital has also been very aggressive in recruiting new physicians and services to the community and in developing strategic planning processes that can allow the hospital to rapidly

> respond to changing conditions. Finally, the Garrett and Allegany Health Departments provide mental health, substance abuse, and STI clinics that can be augmented to meet increased need. There will also be many opportunities to integrate mental health services with somatic care in the next few years in local provider offices. Certainly the pace of natural gas development in Garrett County, if it ever occurs, will determine how rapidly changes to the delivery system must be made.(Glotfelty, 2014).

A different challenge is likely to be faced by the Environmental Health Division of the County Health Departments. If drilling does occur in Western Maryland, there will be pre-drilling sampling as well as ongoing monitoring of drinking water wells in the vicinity of the well pad. Pre-development sampling may identify wells that have existing contamination. In a recent background study in North Carolina, the USGS found that “Concentrations of nitrate, boron, iron, manganese, sulfate, chloride, total dissolved solids, and measurements of pH exceeded federal and state drinking water standards in a few samples. Iron and manganese concentrations exceeded the secondary (aesthetic) drinking water standard in approximately 35 to 37 percent of the samples” (USGS, 2014). Citizens having questions about the testing results are likely to contact the Environmental Health staff in their counties. In addition, residents that perceive any change in the appearance, taste or odor of their well water may request that the Counties test their water. Analyzing water samples can be expensive and responding to citizen complaints can be very time consuming for the staff.

Conclusion

The burden on emergency, urgent care, and trauma care will likely increase if unconventional gas development proceeds in Western Maryland, but the system is likely to be resilient enough to meet the increased demand without jeopardizing public health.

T. Waste and Wastewater Disposal

Background

Solid wastes produced at well sites include drill cuttings, spent drilling muds, sludges, brine scales, and other solid wastes. These wastes need to be disposed of (on-site or off-site), recycled, or beneficially reused.

After a well is hydraulically fractured, some portion of the hydraulic fracturing fluid, called flowback, moves up the wellbore to the surface. Other water that is produced from the well after the initial flowback is termed produced water. These are the major types of wastewater generated at a drill site. Wastewater associated with shale gas extraction can contain high levels of total dissolved solids (TDS), fracturing fluid additives, metals, and naturally occurring radioactive materials. Typically, flowback contains significant concentrations of dissolved sodium, calcium, chloride, barium, magnesium, strontium, and potassium. It can also contain volatile organic compounds. There are a few options for managing this wastewater, including underground injection in regulated Class II injection wells, pretreatment followed by further treatment by a sewage treatment plant, evaporation/crystallization, and recycling.

Data and Discussion

One option for solid waste is on-site disposal, which is the permanent placement of solid drilling waste into a pit within the disturbed area used for HVHF operations. Once filled, the area is reclaimed to prevent erosion. As part of Maryland's Best Management Practices, it will be required that the cuttings and drilling mud should be tested for radioactivity, as well as other contaminants, including sulfates and salinity, before disposal. If the cuttings show no elevated levels of radioactivity, and meet other criteria established by MDE, onsite disposal of the cuttings could be allowed. Current regulations provide "Land farming of cuttings shall be permitted only on approval from the Department and shall require: (1) Soils analysis before site preparation; (2) Cuttings analysis as directed by the Department; and (3) Post land farming soils analysis." The Department has not set criteria in advance, but MDE has significant experience with land application of materials such as sludge from wastewater treatment plants. The criteria could be site-specific.

Solid wastes may also be disposed of in landfills. Maryland's nonhazardous waste landfills include liners designed to prevent the release of hazardous constituents from the landfills. The landfills are also required to do routine groundwater monitoring to detect any releases. Permits for the landfills establish limitations on what the landfills may accept for disposal.

Recycling of gas development wastewaters, and reusing them for hydraulic fracturing, is the most environmentally sound method, and the method that operators have been moving toward. Maryland's Best Management Practices include a recommendation that, unless the permittee can demonstrate that it is not practicable, the permittee be required to recycle not less than 90 percent of the flowback and produced water and carry out that recycling on the pad site where the waste was generated.

Maryland's Best Management Practices also recommend that Maryland should not allow the discharge of any untreated or partially-treated brine, or residuals from brine treatment facilities, into surface waters. Federal regulations already prohibit the direct discharge of these materials into surface waters. Indirect discharge is the introduction of pollutants from a non-domestic source into a publicly owned wastewater treatment system, often called a Publicly Owned Treatment Works (POTW). Indirect discharges to POTWs are subject to General Pretreatment Regulations, which provide that a user of a POTW may not introduce into a POTW any pollutant(s) that cause a POTW to violate its own discharge limitations or that disrupt the POTW, its treatment processes or operations, or the processing, use or disposal of its sludge, and thereby cause the POTW to violate its permit.

There are currently no national standards specifically for the indirect discharge of gas exploration and development wastewaters. EPA has committed to develop standards to ensure that wastewaters from gas extraction receive proper treatment and can be properly handled by POTWs. EPA plans to propose a rule for shale gas wastewater in 2014. Until these regulations are in place, MDE has requested that POTWs not accept these wastewaters without prior consultation with MDE. MDE does not intend to authorize any POTW facility that discharges to fresh water to accept these wastewaters.

With regard to disposal in Class II injection wells, locations in Maryland suitable for siting injection wells may be very limited. Because it is not likely that Class II wells will be located in Maryland, the Best

Management Practices deferred any consideration of this matter unless and until someone proposes to apply for a permit for a Class II injection well.

Finally, in order to assure that all wastes and wastewater are properly treated or disposed of, the Best Management Practices require permittees to keep a record of the volumes of wastes and wastewater generated on-site, the amount treated or recycled on-site, and a record of each shipment off-site. For shipments off-site, the record would have to include information on the type of waste, the volume or weight of waste, the identity of the hauler, the name and address of the facility to which the waste was sent, the date of shipment, and confirmation that the full shipment arrived at the facility. The records would be maintained by the permittee for at least three years, and MDE could audit them during site inspections or otherwise.

Conclusion

Wastes produced at well sites can contain many contaminants that require proper management, including dissolved solids, fracturing fluid additives, metals, naturally occurring radioactive materials, dissolved sodium, calcium, chloride, barium, magnesium, strontium, potassium, and volatile organic compounds.

Maryland's Best Management Practices, as well as current state and federal regulations, ensure that the drilling wastes are managed properly, and that detailed records are kept for all wastes generated, treated or recycled, or shipped off-site.

Section V: Information Gaps

High volume hydraulic fracturing of horizontal boreholes to stimulate the production of oil and gas from less permeable ("tight") formations is a relatively recent development, dating back to around 2006 or 2007. While many tens of thousands of hydraulic fracturing jobs have been carried out throughout the United States, careful analysis of the potential negative consequences of this industrial activity has only just begun. Peer reviewed reports addressing questions about possible environmental contamination or potential public health impacts have only begun to appear in the literature during the last three to four years. As a result, the Departments and the Advisory Commission recognize a number of gaps in our understanding that need to be addressed.

Lack of site specific geological and hydrogeological data

Site specific geological data are required to design and engineer a safe, productive gas well. Much of the required information will be collected by the operators during the exploration phase, relying heavily on 3D seismic surveys to identify the depth and structure of geological formations in the subsurface. These surveys may be capable of identifying faults and other structures that could be problematic if they provide pathways for fracturing fluids under pressure to migrate beyond the target formation, or if they pose any risk of minor earthquakes caused by hydraulic fracturing. Additional essential geological data will result from drilling a pilot hole, enabling the operators to analyze drill cuttings and to record well logs that delineate the thickness and maximum depth of fresh groundwater aquifers. Results of these geological investigations will be reported to MDE as a part of the permitting and reporting requirements.

Beyond the thickness and maximum depth of fresh groundwater at each drilling site, additional hydrogeological data are very important to collect. Does the site contain unconsolidated alluvium[21] or colluvium[22]? How thick is the soil profile and how deep is the water table? How deep is the transition to a fractured hard rock groundwater aquifer, and what are the hydrogeological properties of each surface and subsurface soil/rock type? Finally, what is the nature of subsurface hydraulic gradients at the site – in which direction and how fast does groundwater flow? Answers to these questions are critical for a solid understanding of the potential impacts of an accident or a well failure.

Location of historic gas wells

Media reports from Pennsylvania, which has a long history of numerous oil and gas wells, suggest that historic wells may frequently be abandoned, improperly plugged, and not precisely located in state databases. An abandoned well that is not properly plugged could serve as a conduit for vertical transport of hydraulic fracturing fluid from the target formation to the surface. Something like this has happened on occasion in the vicinity of waste water injection wells (Lustgarten, 2012). Scientific American, "Are fracking wastewater wells poisoning the ground beneath our feet?, June 21, 2012). For

[21] Alluvial soil is made up of grains that have been transported and deposited by running water, such as streams.
[22] Colluvial soil is soil formed from the weathering of bedrock and then moved downslope by rainwash, sheetwash, or gravity.

this reason, the location and structural state of historical gas wells in the region of a drill site, including all of the property overlying the horizontal laterals, must be determined.

Wet vs. dry gas

Based upon regional geological studies and modeling, the Marcellus Shale beneath Maryland is expected to contain dry gas – methane with little or no percentage of larger hydrocarbons such as ethane or propane. However, this expectation is untested. Should the Maryland Marcellus contain wet gas, then estimates of the potential for air emissions especially during well completion may need to be reevaluated.

Technical data gaps

The technology of gas development is constantly changing. Additional types of non-potable water may be suitable for hydraulic fracturing. Wastewater treatment technologies may become more effective or less expensive. As operators and service companies work to improve zonal isolation with casing and specially formulated cement, the rate of well failure and methane migration should be tracked so the most effective technology can be identified. It would be helpful to learn which methods of integrity testing and monitoring for well failure and methane migration are best.

Data on health and community impacts

Additional studies on the health risks of persons living near unconventional gas wells are necessary. Anecdotal reports of acute health effects due to periodic spikes in ambient air pollution levels, and measurements of the frequency and magnitude of such spikes is lacking.

Seismic information

Currently, the Maryland Seismic Network consists of a single seismometer at Soldier's Delight Natural Environment Area in Baltimore County. Although perceptible earthquakes are very rarely associated with hydraulic fracturing, establishing additional permanent seismometers in Western Maryland would improve coverage of the State and reassure the public.

Section VI: Conclusions and Recommendations

The purpose of the Marcellus Shale Safe Drilling Initiative is to help State policymakers and regulators to determine whether and how gas production in the Marcellus Shale in Maryland can be accomplished without unacceptable risks of adverse impacts to public health, safety, the environment and natural resources. Over the last three and a half years, the Departments, in consultation with an Advisory Commission, have been assembling and evaluating information on these questions. It is the judgment of the Department of the Environment and the Department of Natural Resources that, provided all the best practices are followed and the State is able to rigorously enforce compliance, the risks of Marcellus Shale development can be managed to an acceptable level.

The best practices and this conclusion are based on the assumption that the natural gas in the Marcellus Shale in Maryland will be dry gas, with little or no liquid hydrocarbons. If this assumption is not correct, it may be necessary to reevaluate the air pollution issues before proceeding. In this case, the applicants should, at a minimum, be required to model air pollution from the site and perform an Air Toxics review as part of the application process.

The following steps should be taken if Marcellus Shale gas development is to proceed in Maryland.

Confirm effectiveness of best practices.

The Departments are mindful of data and reports from other states about elevated levels of pollutants in the air, contaminated groundwater, and spikes in air pollution that cause acute effects. In most cases, the data and reports were from areas with rapid and intensive gas development, some in jurisdictions where government regulation was not stringent and enforcement was not rigorous. It would be prudent to undertake intensive monitoring of the initial shale gas development projects in Maryland in order to determine whether contamination is occurring. If it is, additional steps must be taken to protect the public.

Monitor air, groundwater and surface water.

The Air and Radiation Management Administration of MDE intends to convene a stakeholders group to evaluate appropriate locations, methods, and frequency for air monitoring. Monitoring of groundwater to detect stray methane or other contamination will continue throughout the life of the well. As a component of any individual permit, an applicant is required to conduct two-years of baseline surface and groundwater monitoring before any drilling can occur. The permit will require continued monitoring of selected locations to ensure that any deviations from baseline conditions resulting from drilling are identified so as to be appropriately addressed.

Use the CGDP to protect the environment and public health.

A mandatory Comprehensive Gas Development Plan is the only means to address landscape level impacts. It can direct development to areas where harm is less likely. Development and approval of the plan need not be onerous or unduly time-consuming.

Reduce the amount of truck traffic.

The elevated risk due to the volume of truck traffic is of concern. Companies should be required whenever possible to establish centralized fresh water storage facilities from which water can be delivered to well pads by aboveground hoses or pipes. Enforcement of weight limits, safety regulations, and sound limits will be necessary to reduce the impact of truck traffic.

Adopt new regulations.

New regulations must be adopted. The existing regulations for oil and gas development in Maryland are out of date and unsuitable for horizontal drilling and high volume hydraulic fracturing. In fact, the existing regulations prohibit the now-common shale gas practice of constructing multiple wells on a single pad because currently "The Department may not issue a permit to drill and complete a gas well closer than 2,000 feet to an existing gas well in the same reservoir unless the Department is provided with credible geologic evidence of reservoir separation to warrant granting a spacing exception" (COMAR 26.19.01.09 E). Codifying the requirements in regulations will not prevent the Department from mandating safer technologies, because by statute, Environment Article, § 14-110 (a)(2), "The Department may place in a permit conditions which the Department deems reasonable and appropriate to assure that the operation shall fully comply with the requirements of this subtitle, and provide for public safety and the protection of the State's natural resources."

Since 2010, the Department of the Environment has been authorized by Environment Article §§ 14-105 and 14-123, to set and collect permit fees in an amount necessary to administer and implement its gas and oil program, including costs incurred by the State to:

> (1) Review, inspect, and evaluate monitoring data, applications, licenses, permits, analyses, and reports;
>
> (2) Perform and oversee assessments, investigations, and research;
>
> (3) Conduct permitting, inspection, and compliance activities; and
>
> (4) Develop, adopt, and implement regulations, programs, or initiatives to address risks to public safety, human health, and the environment related to the drilling and development of oil and gas wells, including the method of hydrofracturing.

The Department had not acted to set the fee because it was not possible to estimate the magnitude of the need until the completion of this report. To ensure proper inspection and enforcement, it is imperative that the fee be set at an appropriate level to support the Comprehensive Gas Development Plan process, review the detailed plans submitted for each well permit, and adequately monitor and enforce compliance with the permit.

Enact legislation.

The enforcement provisions of the existing statute should be revised. The Department's administrative remedies are limited to issuing administrative orders. The Department can go to court to seek an injunction to enforce compliance. Currently, a willful violation is considered a misdemeanor punishable by a fine up to $50,000 and the costs of damages resulting from a spill or other violation. The statute provides no other penalties. The addition of administrative and civil penalty provisions with appropriate fines would help deter violations.

In addition to updating the regulations and strengthening the enforcement provisions, the Departments strongly recommend that the legislature pass a state-level severance tax. The severance tax revenue should be deposited into a Shale Gas Impact Fund to be used for continuing regional monitoring and to address impacts of gas exploration and production that cannot be attributed to a specific operator, or for which there is no solvent responsible entity. The Departments also recommend that Maryland adopt an act to protect the rights of surface owners. The Departments supported the severance tax bill in the 2014 session, and the Departments and the Advisory Commission have advocated for a surface owners protection act since late 2011.

Manage adaptively.

New technologies and additional information about the impacts of shale gas development are constantly emerging. Maryland must follow developments in the field and be prepared to adapt with new regulations or new permit provisions.

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Appendix A: Best Practices

The best practices identified in this Appendix formed the basis for the analysis, findings and conclusions in this report. Unless these practices, or others equally protective of public health, safety, the environment and natural resources, are followed, the conclusions in this report should be reevaluated. The practices were developed specifically for the Marcellus Shale region of Western Maryland and may not be suitable for other shale deposits. Additional information about the best practices and definitions of some terms can be found in the Interim Final Best Practices Report.

A Mandatory Comprehensive Gas Development Plan (CGDP)

1. The purpose of the CGDP is to identify travel routes and the locations for well pads, access roads, pipelines and other ancillary facilities that
    a. Avoid, to the extent possible, adverse site-specific and cumulative impacts to public health, the environment, the economy and the people of Western Maryland;
    b. Minimize the adverse impacts that cannot be avoided; and
    c. Mitigate the remaining impacts.
2. Except for a limited number of exploratory wells, no one may apply for a permit to drill an oil or gas well until the applicant has first obtained the approval of a CGDP and the application is consistent with the approved CGDP.
3. The CGDP should address as much as possible of a company's planned development, but no less than five years.
4. An approved CGDP will remain in effect for ten years, but one renewal for an additional 10 years may be granted by MDE if the resource information is updated, and the locations approved in the initial CGDP are not prohibited under any more stringent location restrictions or setback requirements enacted after the approval of the initial CGDP.
5. Without an approved CGDP, one exploratory well may be permitted, provided it meets all other regulatory requirements, within a circular area having a radius of 2.5 miles centered at the exploratory well.

Location Restrictions and Setbacks

1. No oil or gas well with lateral drilling and hydraulic fracturing shall be permitted unless the there is a separation of at least 2,000 vertical feet between the deepest fresh water aquifer and the target formation.
2. No surface disturbance for pads, roads, pipelines, ponds or other ancillary infrastructure shall be permitted on State-owned land, without the consent of DNR.
3. No well pad may be permitted on land with a slope, before grading, of greater than 15 percent.
4. No well pad may be permitted within the watersheds of any of the following reservoirs:
    a. Broadford Lake
    b. Piney Reservoir
    c. Savage Reservoir
5. The edge of disturbance of a well pad shall be at least

   a. 1,000 feet from the boundary of the property on which the well is to be drilled (the Department may grant an exception if site constraints prevent the setback.
   b. 450 feet from the edge of an aquatic habitat.
   c. 600 feet from special conservation areas.
   d. 300 feet from a cultural or historical site, State or federal parks, trails, wildlife management areas, wild scenic rivers, and scenic byways.
   e. 1,000 feet of known caves.
   f. 750 feet on the downdip side of a limestone outcrop.
   g. 1,000 feet from any occupied building, school or church.
   h. 1,000 feet of a wellhead protection area or a source water assessment area for a public water system for which a Source Water Protection Area (SWPA) has been delineated.
   i. 1,000 feet of the default wellhead protection area for public water systems for which a wellhead protection area has not been officially delineated. [For public water systems that withdraw less than 10,000 gpd from fractured rock aquifers the default SWPA is a fixed radius of 1000 feet around the water well(s).]
   j. Within 1,000 feet of a source water assessment area (SWPA) for a public water system for which a SWPA Area has been delineated.
   k. 2,000 feet from a private drinking water well.
   l. Within an area defined as all lands at an elevation equal to or greater than the discharge of a spring used as the source of domestic drinking water by the resident(s) of the property on which the spring is located, not to exceed 2,500 feet unless the Department approves an alternative based on the delineation of recharge area of the spring.
6. The vertical and horizontal boreholes may not be within 1320 feet of any historic oil or gas well (this does not prohibit new horizontal boreholes from being located within 1320 feet from each other).
7. The setback restrictions for well pads also apply to all gas development activities that result in permanent surface alteration that would negatively impact aquatic habitat, special conservation areas, cultural and historical sites, State and federal parks, forests and trails, wildlife management areas, wild and scenic rivers and scenic byways.

Environmental Assessment

With the application for a permit to drill a well, the applicant must submit an Environmental Assessment that satisfies guidance issued by the department, including two years of baseline monitoring in the vicinity of the well pad. Baseline monitoring must be completed before any site preparation or construction is done at the site of the planned well pad. The applicant must also perform a geological investigation of the area covered by the CGDP, to help identify underground features such as fractures or faults.

Performance Standards and Minimum Requirements

In an application for a permit to drill a well, the applicant shall submit detailed plans for construction and operation of the well that meet or exceed the following performance standards and minimum requirements. In preparing the plan, the applicant shall consider all relevant API Standards and

Guidance Documents, including normative references and, if the plan fails to follow a minimum requirement of a relevant API standard, the plan must explain why and demonstrate that the plan is at least as protective as the minimum requirement. An approved plan shall be incorporated by reference into the well permit.

1. Sediment and erosion must be controlled in accordance with State law for all construction, including the well pad, ponds, access roads and pipelines.
2. There shall be no discharge from the pad as long as any fuels or chemicals are present on the pad.
    a. The pad shall be constructed with an impermeable liner (maximum hydraulic conductivity 10^{-7} cm/sec) and berms so that it is capable of containing, at a minimum, the 25-year, 24-hour precipitation event.
    b. The design must allow for the transfer of stormwater and other liquids that collect on the pad to storage tanks on the pad or to trucks that can safely transport the liquid for proper disposal.
    c. Stormwater collected from the pad may be used for hydraulic fracturing but, prior to use, it must be stored in tanks and not in a pit or pond.
    d. All liquids (except fresh water) shall be stored in watertight, closed tanks or containers with secondary containment capable of holding the volume of the largest tank or container. If the tanks may emit methane or VOCs and are vented to the environment must have pollution control equipment to destroy or capture methane and VOCs.
    e. After all fuel and chemicals are removed from the site, stormwater will be managed in accordance with State law.
3. Only fresh water may be stored in ponds, and the ponds must be properly constructed and lined.
4. Access roads shall be constructed and operated to allow safe passage of vehicles accessing the site and shall include stormwater controls and dust control.
    a. The design, construction and maintenance of unpaved roads be at least as protective of the environment as the standards adopted by the Bureau of Forestry of the Pennsylvania Department of Conservation and Natural Resources.
    b. The standards are contained in *Guidelines for Administering Oil and Gas Activity on State Forest Lands.*
5. Travel for all heavy truck traffic to or from the well pad or to or from centralized facilities serving the well pad shall be planned and implemented to minimize conflicts with the public. The plan at a minimum, shall
    a. Avoid truck traffic during times of school bus transport of children to and from school locations.
    b. Not interfere with public events or festivals.
    c. Minimize truck traffic in residential areas
    d. Minimize conflict with public uses such as hunting and fishing.
6. Drinking water aquifers must be protected from contamination during drilling.

    a. All intervals drilled prior to reaching the depth 100 feet below the deepest known stratum bearing fresh water, or the deepest known workable coal, whichever is deeper, shall be drilled with air, fresh water, a freshwater based drilling fluid, or a combination of the above.
    b. Only additives approved under SNF/ANSI Standard 60: Drinking Water Chemicals may be used for drilling through fresh water aquifers.

7. Wells shall be drilled, cased and cemented to effectively isolate the borehole from the surrounding formations and prevent the migration of gas or liquids into or out of the casing and the formation.
    a. At least one pilot hole must be drilled for each well pad to assist in the identification of geological features, underground voids, gas- or water-bearing formations, and the lowest fresh water aquifer.
    b. The applicant for a drilling permit must submit a plan for MDE's approval that describes, at a minimum, how a stable borehole will be drilled with minimal rugosity (roughness of the borehole wall), how complete removal of drilling fluid will be accomplished, how the cement system design addresses challenges to zonal isolation, how other factors that could interfere with the proper placement of the cement around the casing will be addressed, and how the casing and cement will assure integrity throughout the life cycle of the well.
    c. Adherence to the drilling, casing and cementing plan, as well as integrity testing will be a condition of the permit.
    d. Unless the Department, upon demonstration by the applicant that its proposed drilling, casing and cementing plan is adequately protective, the plan shall meet the following criteria:
        i. The conductor casing must be cemented to the surface.
        ii. The surface casing must extend from the surface to at least 100 feet below the lowest underground source of drinking water and be cemented along its entire length.
        iii. The intermediate casing must be installed and cemented from its greatest depth to the bottom of the surface casing.
        iv. Production casing must be cemented along the horizontal portion of the well bore and to at least 500 feet above the highest formation where hydraulic fracturing will be performed, or to the base of the intermediate casing, whichever is shallower.
        v. A representative sample of each cement formulation shall be tested before use under conditions that are similar to those found in the well where the cement will be used.
        vi. Open hole logging must be performed and used to optimize the design and installation of the well.
    e. All casing installed in a well shall be steel alloy casing that has been manufactured and tested consistent with standards established by the American Petroleum Institute (API) in "5 CT Specification for Casing and Tubing" or ASTM International in "A500/A500M

Standard Specification for Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes" and have a minimum internal yield pressure rating designed to withstand at least 1.2 times the maximum pressure to which the casing may be subjected during drilling, production or stimulation operations.

f. The minimum internal yield pressure rating shall be based upon engineering calculations listed in API "TR 5C-3 Technical Report on Equations and Calculations for Casing, Tubing and Line Pipe used as Casing and Tubing, and Performance Properties Tables for Casing and Tubing."

g. Thread and coupling designs for casing and tubing must meet or exceed the maximum anticipated tensile, compressive, burst and bending stress conditions for the well. Casing strings with threads should be assembled to the correct torque specifications to ensure leak-proof connections.

h. Operators must use a sufficient number of centralizers to properly center the casing in each borehole. The cement shall be allowed to set at static balance or under pressure for a minimum of 12 hours and must have reached a compressive strength of at least 500 psi before drilling the plug, or initiating any integrity testing

i. Reconditioned casing may be permanently set in a well only after it has passed a hydrostatic pressure test with an applied pressure at least 1.2 times the maximum internal pressure to which the casing may be subjected, based upon known or anticipated subsurface pressure, or pressure that may be applied during stimulation, whichever is greater, and assuming no external pressure. The casing shall be marked to verify the test status. All hydrostatic pressure tests shall be conducted pursuant to API "5 CT Specification for Casing and Tubing" or other method(s) approved by the Department. The owner shall provide a copy of the test results to MDE before the casing is installed in the well.

j. Before commencing hydraulic fracturing, the permittee must certify the sufficiency of the zonal isolation to MDE with supporting data in the form of well logs, pressure test results, and other appropriate data.

8. Integrity testing will be required.
   a. An applicant for a drilling permit will be required to provide a plan for integrity and pressure testing of the cased hole for approval by MDE. Segmented radial cement bond logging (SRCBL) shall be used, supplemented by other methods such as omnidirectional cement bond logging and neutron logging.
   b. If there is evidence of inadequate casing integrity or cement integrity, the Department must be notified and remedial action proposed.
   c. Integrity testing must be performed periodically during the lifetime of the well. The specific types of tests and the frequency of testing will be addressed in each permit.
   d. Integrity testing will be required when a well is re-fractured.
   e. All integrity test results must be reported to MDE.
9. Top-down BAT must be implemented on all air pollution emission sources.
   a. Green completion shall be achieved on all gas wells drilled in Maryland.

   b. An applicant for a permit must prepare a Leak Detection and Repair Plan that follows EPA's Leak Detection and Repair: A Best Practices Guide. http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf and submit the plan to MDE for approval. An approved plan shall be incorporated into the permit.
   c. When evaluating top-down BAT, the applicant for the permit must include EPA's Natural Gas STAR Program's Recommended Technologies and Practices, to the extent they apply to the applicant's operations.

10. Offsetting methane emissions
    a. Permittees will be required to estimate the remaining methane emission (after implementing top-down BAT) and report those emissions to MDE annually, converted into CO_2 equivalent emissions.
    b. Where practicable, estimates should be verified by operational data from the permittee's leak detection and repair program.
    c. The methane emissions must be offset. MDE will work with stakeholders to establish a GHG offset program for methane, building from ongoing efforts of the Regional Greenhouse Gas Initiative and other greenhouse gas offset initiatives across the country. If such a system is established, MDE may also require permittees to offset leakage at a ratio greater than 1:1.
11. Flaring shall be allowed only if the content of flammable gas is very low, or when flaring is required for safety. The following circumstances shall not justify flaring:
    a. Inadequate water disposal capacity
    b. Undersized flowback equipment
    c. Except for wells drilled pursuant to a bifurcated permit[23] for exploration only, lack of a pipeline connection
12. When flaring is permitted during well completion, re-completions or workovers[24] of any well, operators must adhere to the following requirements:
    a. Operators must either use raised/elevated flares or an engineered combustion device with a reliable continuous ignition source, which have at least a 98 percent destruction efficiency of methane. No pit flaring is permitted.
    b. Flaring may not be used for more than 30-days on any exploratory or extension wells (for the life of the well), including initial or recompletion production tests, unless operation requires an extension.
    c. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of five minutes during any two consecutive hours.
13. Engines
    a. All on-road and non-road vehicles and equipment using diesel fuel must use Ultra-Low Sulfur Diesel fuel (maximum sulfur content of 15 ppm).

[23] A bifurcated permit can be issued under Md. Env. Code, § 14-106 when the drilling will be conducted in geologic formations not yet proven to be productive. Because the Marcellus shale formation has been demonstrated to be productive, bifurcated permits shall not be issued for drilling in the Marcellus shale in Maryland. Exploratory wells in the Marcellus shale will require a permit under Md. Env. Code, § 14-104.

[24] Workovers include the repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons; the term includes refracturing.

    b. All on-road vehicles and equipment must limit unnecessary idling to 5 minutes.
    c. All trucks used to transport fresh water or flowback or produced water must meet EPA Heavy Duty Engine Standards for 2004 to 2006 engine model years, which include a combined NOx and NMHC (non-methane hydrocarbon) emission standard of 2.5 g/bhp-hr.
    d. Except for engines necessarily kept in ready reserve, a diesel nonroad engine may not idle for more than 5 consecutive minutes. (A ready-reserve state means an engine may not be performing work at all times, but must be ready to take over powering all or part of an operation at any time to ensure safe operation of a process.)

14. Noise shall be reduced to the lowest practicable level.
    a. The Departments will require that applicants provide a power plan that results in the lowest practicable impact from the choice of energy source, including consideration of the impact of noise from on-site generators.
    b. Noise reduction devices must be used on all equipment at the pad site.
    c. Noise modeling must be done to demonstrate that noise levels will be met and noise monitoring after operation begins must be done to confirm.
15. All drilling fluids and cuttings must be managed on the well pad in a closed loop system without the use of a reserve pit for mud or cuttings.
16. Flowback and produced water shall be managed in a closed loop system of tanks or containers at the pad site.
17. Wastes and wastewater must be handled in accordance with law and managed in a way that prevents pollution of the environment.
    a. Permittees will be required to keep a record of the volumes of wastes and wastewater generated on-site, the amount treated or recycled on-site, a record of each shipment off-site and a confirmation that the waste was received at the designated facility.
    b. All trucks, tankers and dump trucks transporting liquid or solid wastes shall be fitted with GPS tracking systems to help adjust transportation plans and identify responsible parties in the case of accidents/spills.
    c. Cuttings, drilling mud, flowback, produced water, residue from treatment of flowback and produced water, and any equipment where scaling is likely to occur or sludge is likely to collect must be tested for radioactivity and disposed of in accordance with law.
    d. If cuttings show no level of radioactivity beyond background, and meet other criteria established by MDE, including sulfates and salinity, MDE may permit on-site disposal of cuttings.
18. Flowback and produced water shall be recycled to the maximum extent practicable. Unless the applicant can demonstrate that it is not practicable, the permit shall require that not less than 90 percent of the flowback and produced water be recycled, and that the recycling be performed on the pad site of generation.
19. Disclosure of chemicals
    a. Applicants for permits to drill gas wells shall be required to provide MDE with the name, CAS number and concentration of every chemical constituent of every commercial

chemical product brought to the site. Unless the applicant attests that the information is a trade secret, this information shall be public information.

b. Following well completion, the operator must provide MDE with a list of all chemicals used in fracturing, the weight of each used, and the concentration of the chemical in the fracturing fluid. Unless the applicant attests that the information is a trade secret, this information shall be public information.

c. If a claim is made that the concentration of a chemical in either a commercial chemical product or the fracturing fluid is a trade secret, the operator must attest to that fact and, in addition to the complete list, provide a second list that includes every chemical by name and CAS number, but does not link the chemical to a specific commercial product or reveal the concentration. This list shall be public information.

d. MDE may share trade secret information with other State and federal agencies that agree to protect the confidentiality of the information.

e. The operator must provide the local emergency response agency with the list of chemicals (or the second list, in the event trade secrecy is claimed) and provide a copy of the Safety Data for every commercial product brought to the well site that contains an OSHA hazardous chemical.

f. A health care professional who states, orally or in writing, that he or she needs the trade secret information to diagnose or treat a patient, must be given that information immediately and may use it only as medically necessary.

g. Upon written request and statement of need, certain public health care professionals must be given the information, but the delivery may be conditioned on the execution of a confidentiality agreement.

h. A person claiming trade secret must provide the supplier's or service company's contact information, including the name of the company, an authorized representative, and a telephone number answered 24/7 by a person with the ability and authority to provide the trade secret information in accordance with the regulations.

20. Gathering lines shall be properly constructed and operated to prevent any leaks.

a. The owner and operator of any pipeline shall participate as an "owner-member" as that term is defined in the Maryland Public Utilities Code, Section 12-101, in a one-call system, which in Maryland is generally known as the "Miss Utility" program. Upon the request of someone planning to excavate in the area, the locations of these pipelines could be marked so that the digging could avoid them.

b. All pipelines and fittings appurtenant thereto used in the drilling, operating or producing of oil and/or natural gas well(s) shall be designed for at least the greatest anticipated operating pressure or the maximum regulated relief pressure in accordance with the current recognized design practices of the industry.

21. The well must be protected against blowouts.

a. The well must be equipped with blowout prevention equipment with two or more redundant mechanisms.

b. Blow out preventers must be tested at a pressure at least 1.2 times the highest pressure normally experienced during the life of the blow out preventer. If this highest pressure occurs during well stimulation, it must be tested at a pressure at least 1.2 times higher than that experienced during well stimulation.

  c. The blow out preventer must be tested on a weekly basis.

22. The operator must perform a tiltmeter or microseismic survey for the first well hydraulically fractured on each pad to provide information on the extent, geometry and location of fracturing. The permittee shall provide this information to MDE
23. Diesel fuel shall not be used in hydraulic fracturing.
24. A methane leak detection and repair plan that conforms to EPA's Natural Gas STAR Program guidelines and EPA's best practice guidelines for leakage detection and repair programs must be submitted to MDE for approval with the application for a well permit. It must address leak detection and repair from wellhead to transmission line and assure prompt repair of leaks. Records of leak detection and repair shall be made available to MDE upon request.
25. Night lighting may be used only when necessary, it must be directed downward, and low pressure sodium light sources must be used wherever possible. If drill pads are located within 1,000 feet of aquatic habitat, screens or restrictions on the hours of operation may be required to reduce light pollution further. Light restrictions and management protocols must also minimize conflicts with recreational activities, in addition to minimizing stress and disturbance to sensitive aquatic and terrestrial communities.
26. The applicant must submit a plan with every well application for preventing the introduction of invasive species (plants and animals) and controlling any invasive that is introduced. The invasive species management plan should emphasize avoidance, early detection and rapid response. Invasive species monitoring will be required at the appropriate times of the year to identify early infestations. The plan must include, at a minimum:
    a. flora and fauna inventory surveys of sites prior to operations, including water withdrawal sites;
    b. procedures for avoiding the transfer of species by clothing, boots, vehicles; and water transfers including assuring that the water withdrawal equipment is free from invasive species before use and before it is removed from the withdrawal site;
    c. interim reclamation following construction and drilling to reduce opportunities for invasion;
    d. annual monitoring and treatment of new invasive species populations as long as the well is active; and
    e. post-activity restoration to pre-treatment community structure and composition using seed that is certified free of noxious weeds.
27. Each applicant for a well permit must prepare and submit to MDE for approval a site-specific emergency response plan for preventing the spills of oil and hazardous substances. The plan should include, at a minimum:
    a. using drip pans and secondary containment structures to contain spills,
    b. conducting periodic inspections,
    c. using signs and labels,
    d. having appropriate personal protective equipment and appropriate spill response equipment at the facility,

e. training employees and contractors, and
f. establishing a way of informing local water companies promptly in the event of spills or releases,
g. consulting with the governing body of the local jurisdiction in which the well is located to verify that local responders have appropriate equipment and training to respond to an emergency at a well, and
h. establishing a communications plan.

28. The operator shall identify specially trained and equipped personnel who could respond to a well blowout, fire, or other incident that personnel at the site cannot manage. These specially trained and equipped personnel must be capable of arriving at the site within 24 hours of the incident.
29. The operator shall secure the site. At a minimum, security shall include:
    a. Perimeter fencing
    b. Providing local emergency responders with duplicate keys to locks
    c. Posting appropriate signage
30. The operator shall reclaim the site in two stages: interim reclamation following well completion to stabilize the ground and reduce opportunities for invasive species and final restoration using species native to the geographic range and seed that is certified free of noxious weeds. Reclamation shall address all disturbed land, including the pad, access roads, ponds, pipelines and locations of ancillary equipment. Pre-development and post-development photographic documentation will be required to ensure site closure conditions are satisfied.

Monitoring, Recordkeeping and Reporting

1. State agencies will develop standard protocols for baseline and environmental assessment monitoring, recordkeeping and reporting. In addition, the State agencies will develop standards for monitoring during operations at the site, including drilling, hydraulic fracturing, and production.
2. All information collected at the site and within the study area must be reported according to the State developed guidelines. This is to include monitoring and assessment data for air and water quality, terrestrial and aquatic living resources, invasive species, well logs, other geophysical assessments, such shale fracturing characteristics and additional information as required by the State.
3. State agencies will require more extensive testing of surface water and ground water parameters both randomly and in instances where elevated levels have been detected.