



MARCELLUS SHALE SAFE DRILLING INITIATIVE STUDY

PART II

INTERIM FINAL BEST PRACTICES

July 2014

Prepared By:

Maryland Department of the Environment
Maryland Department of Natural Resources

Prepared For:

Martin O'Malley, Governor
State of Maryland

Thomas V. Mike Miller, Jr., Senate President
Maryland General Assembly

Michael E. Busch, House Speaker
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Prepared pursuant to Executive Order 01.01.2011.11



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EXECUTIVE SUMMARY

Governor O'Malley's Executive Order 01.01.2011.11 established the Marcellus Shale Safe Drilling Initiative. An 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 State has not yet determined whether gas production can be accomplished without unacceptable risk and nothing in this report should be interpreted to imply otherwise.

The Executive Order tasks 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 will include:

- 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 gas production from the Marcellus Shale that may occur in Maryland, was completed in December 2011. This is the second report, Part II of the study.

In preparation for the Part II report, 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. Those recommendations and drafts of this report were considered by the Advisory Commission at several meetings.

The Departments evaluated whether to add to, accept, reject, or modify the suggestions, based on a number of factors, including comments from the Advisory Commission. 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. After consideration of the comments, the Departments submit this interim final report on Part II of the study, Best Practices.

The most innovative recommendation in the UMCES-AL Report is to use comprehensive planning for foreseeable gas development activities in an area rather than considering each well individually. By considering the placement of well pads, roads, pipelines and

other ancillary equipment for a large area, the efficiency of the operation could be maximized while the impacts on local communities, ecosystems, and other natural resources could be avoided or minimized. The UMCES-AL Report recommended that a comprehensive plan be voluntary.

The Departments agree that a Comprehensive Gas Development Plan (CGDP) designed to address the larger, landscape-level issues and cumulative effects offers significant benefits to both the industry and the public. Except for a limited number of exploratory wells, the Departments propose to make a CGDP mandatory in Maryland and a prerequisite to an application for a well permit. The CGDP would be developed by the company through a process that allows public participation and then submitted to the State for approval. Once the CGDP is approved, applications for individual wells consistent with the approved plan could be made.

Whereas the CGDP establishes the locations for well pads, roads, pipelines and other ancillary equipment, the application for an individual well permit will require detailed plans for all activities, from construction of the access road through closure and restoration of the site. The elements of the plan must meet or exceed standards for engineering, design and environmental controls that are recommended in this report. These standards address activities from the initial construction of the access road and pad through closure and restoration of the site. They address sediment and erosion control, stormwater management, transportation planning, water acquisition, storage and reuse, disclosure of chemicals, drilling, casing and cement, blowout prevention, hydraulic fracturing, flowback and produced water, air emissions, wastewater treatment and disposal, leak detection, light, noise, invasive species, spill prevention control and emergency response, site security and closure and reclamation. These standards do not preclude the use of new and innovative technologies that provide greater protection of public health, the environmental and natural resources.

The report also makes recommendations relating to monitoring, recordkeeping and reporting. Appendices provide additional information on specific subjects and include comments of the Advisory Commission and a summary of and response to public comments.

The issuance of this interim final report is not the end of the process for identifying best practices. Additional information, including a report on public health and a risk assessment¹ currently in process, could result in the modification of the best practices in this report or the addition of best practices. As technology improves, better practices are likely to be identified. Maryland regulations could be amended to reflect the new best practices or the new best practices could be required by provisions in an individual well permit.

¹ The risk assessment will assume that all the best practices in this report are adopted.

SECTION I – ORGANIZATION OF THE REPORT

The Maryland Departments of the Environment and Natural Resources acknowledge the excellent work of the University of Maryland Center for Environmental Science – Appalachian Laboratory (UMCES-AL), and in particular Keith N. Eshleman, Ph.D. and Andrew Elmore, Ph.D., for their work in preparing *Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland* (the UMCES-AL Report). The UMCES-AL Report is organized into ten chapters, each devoted to protecting one aspect of the environment, natural resources, public health and safety. In order to facilitate the incorporation of the recommendations into a regulatory and permitting program, however, we have chosen to organize this report differently. Within each section, the relevant UMCES-AL recommendations are listed by their alphanumeric designation as it appears in the UMCES-AL Report. (The same UMCES-AL recommendations may be referenced in multiple sections.) The remainder of the section reflects the Departments evaluation.

Section II provides background information and an overview of activities in Maryland related to the Marcellus Shale. In addition, it summarizes the work of the Advisory Commission.

Section III focuses on comprehensive planning, particularly the concept of planning for the extraction of gas in a large area in order to avoid adverse impacts and minimize those that cannot be avoided. This comprehensive planning would occur before the issuance of a permit to drill any well.

Section IV addresses restrictions on the locations of well pads, pipelines, access roads, compressor stations, and other ancillary facilities. Some ecologically important areas, recreational areas and sources of drinking water may be fully protected only if certain activities are precluded there. In other cases, set back requirements may be sufficient. This section also describes siting best practices.

Section V establishes requirements for planning documents for individual wells.

Section VI deals with engineering, design, and environmental controls and standards. This includes, among other things, pad and access road design, the use of tanks rather than ponds for storing wastewater, air pollution controls, casing and cementing standards, integrity testing, emergency plans, waste disposal, and closure.

Section VII describes best practices for monitoring, recordkeeping and reporting. Pre-application monitoring and monitoring during drilling, well completion, and production are addressed. The response to monitoring results that suggest impacts is also discussed. Inspections and enforcement are included in this section.

Section VIII includes miscellaneous recommendations.

Section IX discusses modifications to the permitting process.

Section X is a roadmap for implementing the recommendations.

Included as Appendices are: the names of the Advisory Commission members, comments of the Advisory Commission, the response to public comments, a constraint analysis, a discussion of Marcellus shale and recreational and aesthetic resources in western Maryland, a link to the UMCES-AL Report, a comparison of the UMCES-AL recommendations with those of the Departments, an explanation for the chosen setback from aquatic habitats, and a list of acronyms.

SECTION II – OVERVIEW

A. Marcellus Shale

Geologists have long known about the gas-bearing underground formation known as the Marcellus Shale, which lies deep beneath portions of the Appalachian Basin, including parts of Western Maryland. Until advances in horizontal drilling and high volume hydraulic fracturing (HVHF) and the combination of these two technologies, few thought that significant amounts of natural gas could be recovered from the Marcellus Shale. Drilling in the Marcellus Shale using horizontal drilling and HVHF began around 2005 in Pennsylvania and has accelerated rapidly.

The production of natural gas has the potential to benefit Maryland and the United States. Tapping domestic sources could advance energy security for the United States. When burned to generate electricity, natural gas produces lower greenhouse gas emissions than oil and coal, which could help to reduce the impact of energy usage as we transition to more renewable energy sources. The exploration for and production of natural gas could boost economic development in Maryland, particularly in Garrett and Allegany Counties.

As gas production from deep shale and the use of HVHF has increased, however, so have concerns about its potential impact on public health, safety, the environment and natural resources. Although accidents are relatively rare, exploration for and production of natural gas from the Marcellus Shale in nearby states have resulted in injuries, well blowouts, releases of fracturing fluids, releases of methane, spills, fires, forest fragmentation, damage to roads, and allegations of contamination of ground water and surface water. Other states have revised or are in the process of reevaluating their regulatory programs for gas production or assessing the environmental impacts of gas development from the Marcellus Shale. A significant amount of research has been completed on HVHF and gas production from the Marcellus Shale, but additional research by governmental entities, academic organizations, environmental groups and industry is currently underway focused on drinking water, public health, natural resources, wildlife, community and economic implications, production technologies and best practices.

B. Developments in Maryland

The Maryland General Assembly has entrusted the permitting and regulation of oil and gas exploration and development in Maryland to the Department of the Environment. With a few notable exceptions, the statutory language is general and MDE is authorized to promulgate rules and regulations and to place in permits conditions it deems reasonable and appropriate to assure that the operations are carried out in compliance with the law and provide for public safety and the protection of the State's natural resources. Md. Env. Code Ann., §§ 14-103 and 14-110. The Department's regulations on oil and gas wells have not been revised since 1993 and thus were written before recent advances in technology and without the benefit of more recent research.

The Maryland Departments of the Environment (MDE) and Natural Resources (DNR) have roles in the evaluation of natural gas projects. Each would be involved in any future permitting decisions for drilling in the Marcellus Shale.

The mission of the Maryland Department of the Environment is to protect and restore the quality of Maryland's air, water, and land resources, while fostering smart growth, economic development, healthy and safe communities, and quality environmental education for the benefit of the environment, public health, and future generations. In addition, MDE is specifically authorized by statute to issue permits for gas exploration and production. The Department of the Environment is required to coordinate with the Department of Natural Resources in its evaluation of the environmental assessment of any proposed oil or gas well.

The Department of Natural Resources leads Maryland in securing a sustainable future for our environment, society, and economy by preserving, protecting, restoring, and enhancing the State's natural resources. In addition, DNR owns or has conservation easements on substantial acreage in the State, including western Maryland.

The first application for a permit to produce gas from the Marcellus Shale in Maryland using horizontal drilling and HVHF was received in 2009.² To address the need for information to evaluate these permit applications properly, the Governor issued the Marcellus Shale Safe Drilling Initiative in Executive Order 01.01.2011.11 on June 6, 2011.

C. The Executive Order and the Advisory Commission

Executive Order 01.01.2011.11 directs MDE and DNR to assemble and consult with an Advisory Commission in the study of specific topics related to horizontal drilling and HVHF in the Marcellus Shale.³ The Advisory Commission 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 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. Appendix A is a list of the Commissioners.

The Executive Order tasks MDE and DNR, in consultation with the Advisory Commission, with conducting a study and reporting findings and recommendations in three reports. The Commission is staffed by DNR and MDE. The reports were to include:

- (i) By December 31, 2011, a presentation of findings and related recommendations regarding the desirability of legislation to establish revenue sources, such as a State-

² Additional applications were received in 2011. Applications for a total of seven wells were received by MDE, but all have been withdrawn. In general, interest in drilling has shifted to areas where not only natural gas but also natural gas liquids that are more valuable, can be produced from formations. It is not likely that Maryland's Marcellus shale contains natural gas liquids.

³ Although the Governor's Executive Order is directed specifically at the Marcellus Shale and HVHF, there is a potential for gas extraction from other tight shale gas formations, including the Utica Shale, and by well stimulation techniques other than HVHF. The findings and conclusions regarding gas exploration in the Marcellus Shale may or may not apply to other formations and techniques.

level severance tax, and the desirability of legislation to establish standards of liability for damages caused by gas exploration and production;

(ii) By August 1, 2012, recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland; and

(iii) No later than August 1, 2014, 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.

The first [report](#)⁴ 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.

D. The Work of the Advisory Commission

The Governor announced the membership of the Advisory Commission in July, 2011, and the Commission has met 28 times through May 2014. Most meetings were in Allegany or Garrett Counties, but several were held in Hagerstown, Annapolis and Baltimore. The Departments have provided written information and briefings to the Advisory Commission on issues relating to HVHF. Speakers representing the scientific community, industry and agencies from Maryland and other states have presented information to the Advisory Commission and the Departments. The Commissioners were able to visit active drilling sites. The Departments have 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 Commission recognized the importance of obtaining background data on air and water quality in advance of any drilling. DNR has begun collecting data to establish pre-drilling baseline conditions. Limited by existing funding and staff, DNR and MDE were not able to fully implement the comprehensive baseline monitoring program recommended by the Departments and the Advisory Commission in its Part I report. DNR has, however, expanded and modified its monitoring program to include 12 continuous water monitoring sites chosen for their relevance to potential gas development. DNR also began a volunteer partnership with Garrett County watershed associations, Trout Unlimited and other citizens where volunteer stream waders are collecting baseline water and biological data from over 70 stream segments. More information on [stream monitoring in the Marcellus shale region](#)⁵ can be found online.

DNR conducted a natural resource assessment of Garrett County to identify high quality streams known for biodiversity and brook trout resources, landscape values, ecological resources, forest interior dwelling species habitats, areas supporting rare, threatened and endangered plants and animals, community water supplies, State lands, trail networks, recreational assets, and areas of particular scenic value that could be impacted, directly or

⁴ www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Meetings/Marcellus_Shale_Report_Part_I_Dec_2011.pdf

⁵ <http://www.dnr.state.md.us/streams/marcellus.asp>

indirectly, by drill pads, pipeline/road construction and use. The findings, [Marcellus Shale Gas Development in Maryland: A Natural Resource Analysis](#),⁶ were presented to the Commission on February 27, 2012.

MDE funded the Maryland Geological Survey (MGS) to perform a limited study of methane levels in drinking water wells in Garrett County. MGS evaluated methane samples from 49 wells in 2012 and an additional 28 wells in 2013 in Garrett County and western Allegany County and issued a report, [Dissolved-Methane Concentrations in Well Water in the Appalachian Plateau Physiographic Province of Maryland](#),⁷ in 2013.

The Departments, in consultation with the Advisory Commission, convened a committee to evaluate necessary revisions to existing statutes and the need for new legislation to address liability, revenue, leases and surface owner's rights. The Departments and the Advisory Commission coordinated with representatives of the House Environmental Matters Committee and the Senate Education, Health and Environment Committee. This effort is ongoing.

In the 2012 session of the General Assembly, a bill entitled Environment - Presumptive Impact Areas -Contamination Caused by Gas Wells in Deep Shale Deposits (HB1123) was passed establishing an area around a gas well within which it is presumed that contamination of a drinking water well was caused by gas well activities if it occurred within one year of the activities. Delegate Mizeur, a member of the Commission, sponsored the bill.

In the 2013 session of the General Assembly, bills passed that had been introduced by Senator George Edwards, a member of the Commission: Business Occupations – Oil and Gas Land Professionals (SB766, HB828); and Environment – Gas and Oil Drilling – Financial Assurance (SB854). Landmen will now have to register with the Department of Labor, Licensing, & Regulation. The financial assurance bill lifts the cap on the closure and reclamation bond and requires a minimum level of environmental impairment insurance in addition to general comprehensive liability insurance.

Also in 2013, the Governor proposed and the legislature approved a supplemental Fiscal Year 2013 appropriation that provided MDE with \$1 million and DNR with \$500,000 to complete the studies required under the Executive Order. The Departments are using this money, among other things, to expand the pre-drilling monitoring of air and water, and undertake an economic study and a public health study.

In furtherance of developing Best Practices recommendations, MDE contracted 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 principal investigators, Keith N. Eshleman, Ph.D. and Andrew Elmore, Ph.D., compiled best practices from five states (Colorado, New York, Ohio, Pennsylvania, and West Virginia), as well as the recommendations of expert panels and organizations. The survey was completed and made available to the Commission. The report, [Recommended Best](#)

⁶ www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Eshleman_Elmore_Final_BMP_Report_22113_Red.pdf

⁷ www.mgs.md.gov/publications/report_pages/ADMIN_14-02-01.html

[Management Practices for Marcellus Shale Development in Maryland](#)⁸ (the UMCES-AL Report), was made available to the Commission and the public in February 2013 and a link to it is included as Appendix F. The Departments also charted a comparison of the recommendations of UMCES-AL and the Departments; it is also included in Appendix F.

As the Departments reviewed that report and consulted with the Advisory Commission, all of the recommendations in the UMCES-AL Report were considered. The Departments evaluated whether to add to, accept, reject, or modify the recommendations based on a number of factors, including the opinions of the Advisory Commission, the expertise of Departmental staff, and judgments about environmental protection, technical practicability, and administrative feasibility.

The draft best practices report (“Draft Report”) was made available for public comment on June 25, 2013. The initial date for closing the comment period, August 9, 2013, was extended to September 10, 2013. More than 4,000 comments were received. Having considered all of the comments, including those of the Advisory Commission, the Departments submit this final report on Part II of the study, Best Practices.

The issuance of this report is not the end of the process for identifying best practices. Additional information, including a report on public health and a risk assessment⁹ currently in process, could result in the modification of the best practices in this report or the addition of best practices. As technology improves, better practices are likely to be identified. Maryland regulations could be amended to reflect the new best practices or the new best practices could be required by provisions in an individual well permit. The State has not yet determined whether gas production can be accomplished without unacceptable risk and nothing in this report should be interpreted to imply otherwise.

⁸ http://www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Meetings/MAC_NaturalResourcesAnalysis.pdf

⁹ The risk assessment will assume that all the best practices in this report are adopted.

SECTION III – COMPREHENSIVE GAS DEVELOPMENT PLANS

UMCES-AL Report recommendation 1-A, 1-C, 1-G, 5-A, 5-A.1, 5-A.3, 5-F, 5-F.1, 6-A, 6-C, 6-D, 6-E, 6-F, 6-J, 7-A, 7-A.1, 7-D, 7-D.1, 8-A, 8-B, 8-E, 9-A, 9-A.1, 9-A.2, 9-A.3, 9-E, 9-E.1, 9-G, 10-B

The authors of the UMCES-AL Report suggest that the single most important recommendation in their report is the comprehensive drilling plan. They recommend that the State should institute a voluntary program whereby a company holding gas interests could prepare and submit for State approval a comprehensive drilling plan for a large geographic area before applying for any permit to drill a specific well. They suggested that incentives could be offered, such as expedited processing of permits for individual wells included in the comprehensive drilling plan.

The Departments agree that a comprehensive plan offers great advantages, but we recommend that the program be mandatory rather than voluntary. In the Draft Report, we proposed that Maryland require, as a prerequisite to the issuance of any permit to drill a gas exploration, extension, or production well, that the prospective applicant first submit a Comprehensive Gas Development Plan (CGDP). Commenters noted that basic information that can only be obtained by an exploratory well would be necessary before a company could write a CGDP. If a company were required to prepare a CGDP before drilling exploratory wells, there would be a high likelihood that the information obtained from exploratory wells would necessitate a substantively different CGDP.

The Departments are therefore proposing that one exploratory well can be drilled within a circular area having a radius of 2.5 miles centered at the exploratory well. This area is approximately 20 square miles. The exploratory well must comply with all of the location restrictions, setbacks, and other requirements for an individual well permit, including two years of predevelopment baseline monitoring and a rapid site assessment. No additional wells, exploratory or production, can be drilled within that area until a CGDP has been approved. Absent a determination by the Department that the exploratory well can be connected to a transmission line without any adverse impact on wetlands, forest, or nearby residents, the exploratory well cannot be converted to a production well until a CGDP for that area is approved.

We believe that the program can be structured so that obtaining a CGDP is not unduly burdensome to the applicant, allows industry the flexibility to respond to changing conditions, and still achieves its purpose of reducing adverse and cumulative effects. The CGDP will address the locations for activities, but not the well-specific requirements of an individual permit. The processes, therefore, will not be duplicative.

The CGDP should address, at a minimum, all land on or under which the applicant expects to conduct exploration or production activities over a period of at least the next five years. The CGDP could be submitted by a single company or by more than one entity for an assemblage of land in which multiple entities hold mineral rights. The CGDP must address the locations of well pads, roads, pipelines and ancillary facilities

related to exploration or production activities from the identified land, but the CGDP is not a commitment on the part of the applicant to install any of the facilities, or to proceed in a particular sequence.

CGDPs provide an opportunity to address multiple aspects of shale gas development from a holistic, broad-scale planning perspective rather than on a piecemeal, site-by-site basis. By considering the entire project scope of a single company, or multiple companies simultaneously, responsible energy development could proceed while minimizing public health conflicts and addressing the concerns associated with maintaining the rural character of western Maryland and protecting high value natural resources and resource-based economies. To cite just one example, land disturbance could be minimized if infrastructure were shared or located within the same right of way. Proactive, upfront planning at a landscape scale provides the framework for evaluating and minimizing cumulative impacts to the environmental, social and economic fabric of western Maryland. The Departments agree that a CGDP process will be beneficial and recommend that this be a mandatory prerequisite before any individual permit for a production well would be issued. The associated recommendations from the UMCES-AL Report, as listed as above, are generally accepted by the Departments for planning guidelines. The outline below provides a conceptual framework.

A. Application Criteria and Scope

1. Companies intending to develop natural gas resources are required to submit a CGDP for the area where the applicant may conduct gas exploration¹⁰ or production activities and install supporting infrastructure (compressor stations, waste water treatment facilities, roads, pipelines, etc.) for a period of at least five years.
2. Companies whose geographic planning units overlap are encouraged to develop integrated plans to improve use of existing and new infrastructure, to share or co-locate infrastructure, and to minimize cumulative impacts.
3. A company is not obligated to develop all the pads, wells or supporting infrastructure identified in the plan.
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.

B. Planning principles

1. Use multi-well, clustered drilling pads to minimize surface disturbance.
2. Comply with location restrictions, setbacks and other environmental requirements of State and local law and regulations.
3. Observe and comply with all location restrictions and setbacks in Section IV and locate wells, pads and infrastructure to avoid, minimize and mitigate impact on public health and human and natural resources.

¹⁰ One exploratory well can be drilled within a circular area having a radius of 2.5 miles centered at the exploratory well before a CGDP is submitted.

4. Preferentially locate operations on disturbed, open lands or lands zoned for industrial activity.
5. Co-locate linear infrastructure with existing roads, pipelines and power lines.
6. Consider impacts from other gas development projects and land use conversion activities and plan to minimize cumulative surface impacts.
7. Avoid surface development beyond 2 percent of the watershed area in high value watersheds. This threshold is based on the ecological sensitivity of specific aquatic organisms within these high value watersheds. Other factors, as discussed in the location restriction and setbacks section will also limit the location and extent of surface development.
8. Minimize fragmentation of intact forest, with particular emphasis on interior forest habitat.
9. The Departments will incorporate the concept of “noise sensitive locations” into its review of the CGDP.
10. Adhere to Departmental siting policies (to be developed) to guide pipeline planning and direct where hydraulic directional drilling and additional specific best management practices are necessary for protecting sensitive aquatic resources when streams must be crossed.
11. Additional planning elements include
 - a) Identification of travel routes.
 - b) A generalized water appropriation plan that identifies the proposed sources and amounts of water needed to support the plan.
 - c) Sequence of well drilling over the lifetime of the plan that places priority on locating the first well pads in areas removed from sensitive natural resource values.
 - d) Consistency with local zoning ordinances and comprehensive planning elements.
 - e) Identification of all federal, State and local permits needed for the activities.

C. Procedure and Approval Process

1. An applicant with the right to extract natural gas shall prepare a preliminary CGDP that best avoids and then minimizes harm to human, natural, social, cultural, recreational and other resources, and mitigates unavoidable harm.
2. The CGDP shall include a map and accompanying narrative showing the proposed location of all planned wells, well pads, gathering and transmission lines, compressor stations, separator facilities, access roads, and other supporting infrastructure.
3. An applicant must conduct a geological survey of the area covered by the CGDP to help identify historic gas wells and faults. At a minimum, the geological survey will include 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. The applicant will be required to submit the survey data to the State in a report with the application for the CGDP.

4. The State will develop a Shale Gas Development Toolbox that will include GIS data and provide it to companies that wish to prepare a CGDP. The applicant's preliminary Environmental Assessment shall be based on the data in the Toolbox, supplemented with other information as needed, including a rapid field assessment for unmapped streams, wetlands and other sensitive areas. A detailed description of the shale Gas Development Toolbox is provided in section E, below.

5. State agencies and local government agencies review the CGDP, evaluate opportunities for coordinated regulatory review and present comments to the applicant to direct any needed alternative analyses for review. This review will be completed within 45 days of submission by the applicant of the CGDP.

6. The public review and approval process is mandatory and will be initiated upon request of the applicant following receipt of agency comments.

7. A stakeholders group that includes the company, local government, resource managers, non-governmental organizations, and surface owners will be convened; in a facilitated process that shall not exceed 60 days, to discuss and improve the plan.

8. The plan shall be presented at a public meeting by the applicant and the public shall be allowed to comment on the plan.

9. The applicant may further modify the plan based on alternatives analyses and public comment before submitting it to the State for approval.

10. In evaluating the CGDP, the State shall determine whether the plan conforms to all regulatory requirements concerning location, and shall consider the plan and the comments of the stakeholders and public.

11. If the State determines that the CGDP conforms to regulatory requirements and, to the maximum extent practicable, avoids impacts to natural, social, cultural, recreational and other resources, minimizes unavoidable impacts, and mitigates remaining impacts, the State shall approve the CGDP.

12. Once the CGDP is approved, the entity may file a permit application that is consistent with the plan for one or more wells.

13. Significant modification to the original plan, such as a significant change in location of a drilling pad, or the addition of new drilling pads, will require the submission and approval of a modified CGDP application. Modifications that cause no surface impact, such as the installation of additional wells on an existing pad or a change in the sequence of development shall be approved by the State upon request of the applicant.

D. Benefits of a Comprehensive Gas Development Plan

An approved, high quality CGDP could result in numerous benefits for all parties. These benefits, particularly those related to improved coordination and expedited permit review, are still under discussion among the review agencies, but could include:

1. Better protection of natural, social, cultural, recreational and other resources, and reduced cumulative impact.
2. Early identification of alternatives to avoid, minimize and mitigate impacts to wetlands and waterways , such as those associated with pipeline networks and road construction, that require a comprehensive alternatives analysis scenario.
3. Preliminary approval for drill pad locations, allowing the applicant to initiate baseline monitoring and begin application for individual well permits.
4. More efficient processing of other environmental approvals and permits, such as air quality and water appropriation and use.
5. Opportunities to implement mitigation actions prior to permit approval or in advance of project development.
6. Reduced need for multiple public hearings.¹¹
7. Reduced expense and risk associated with leveraging existing infrastructure and centralizing various processing needs.
8. Reduced public use conflict and improved public good will.

E. The Shale Gas Development Toolbox

The toolbox will provide access to geospatial planning data necessary to address the CGDP. The data will be available for download, and can be viewed through a publically accessible interactive mapping application. The mapping application will be very similar to DNR’s **MERLIN** online tool¹² but will be tailored to include the geospatial data needed for developing and evaluating the CGDP. Users of this data should be aware that actual site and landscape conditions may not be accurately reflected in the mapped information. Many fine scale environmental features, such as headwater streams or small wetlands, are often not mapped. In addition, the effects of recent land use change may not be reflected in the mapped datasets. For this reason, and to evaluate other site specific factors, additional site assessment data will need to be collected by the applicant to meet the requirements of the CGDP. The planning datasets that will be included in the toolbox include those related to the elements discussed in Section IV. A. Location Restrictions and Setbacks and in Section IV. B. Siting Best Practices. Additional datasets may be added to improve the CGDP process.

1. Planning objective: Leveraging existing infrastructure.
 - a. State and county roads
 - b. Existing rights of way for gas lines and transmission lines
 - c. Land use/land cover data for identifying industrial land uses
2. Planning element: Location restrictions and setbacks that indicate where certain gas development activities are restricted.

¹¹ The CGDP does not in any way excuse compliance with any of the procedural or substantive requirements for other permits, and citizens will be afforded all of their public participation rights, including hearing rights.

¹² <http://dnrweb.dnr.state.md.us/merlin/>

- a. Streams, rivers and flood plains – stream maps will include designated use classifications
 - b. Wetlands
 - c. Steep slopes (> 15 percent)
 - d. Drinking water reservoirs and their watersheds
 - e. Irreplaceable Natural Areas (BioNet Tier 1 and 2 areas)
 - f. Cultural and historic areas, including National Registry sites
 - g. Local, State and federal parks
 - h. Wildlands
 - i. State forests and other DNR lands
 - j. Wild and scenic rivers
 - k. Scenic byways
 - l. Mapped limestone outcrops and known caves
 - m. Historic gas wells
 - n. Well head protection areas and source water assessment areas for public water systems
 - o. Geological fault areas
3. Planning element: Additional siting criteria to guide avoidance, minimization and mitigation of potential impacts.
- a. Land use land cover for preferentially siting activities on open, disturbed land or areas in industrial use and avoiding forested areas.
 - b. High value watersheds (Tier II, Brook trout and Stronghold watersheds) where surface area impacts should not exceed the ecological threshold of 2 percent of the watershed area.
 - c. Forest interior dependent species (FIDS) habitat - large contiguous forest patches important for supporting FIDS
 - d. Green Infrastructure Hub and Corridor network - a system of large habitat areas connected to each other through corridors that are important for allowing plant and animal migration.
 - e. Forests important for protecting water quality - forested areas that have exceptional value for maintaining clean and cool water quality for streams and rivers.
 - f. BioNet habitat areas - habitat important for wildlife and rare species. This dataset includes Irreplaceable Natural Areas (Tier 1 and 2 areas) and other important habitats (Tier 3, 4 and 5 areas).
 - g. GreenPrint Targeted Ecological Areas – high value lands and waters that are eligible for State conservation funding through Program Open Space.
 - h. Recreational use considerations to minimize public use conflicts based on the results of the participatory GIS workshop conducted in November of 2013.
 - i. Lands protected by conservation easements
 - j. Mapped underground coal mines
 - k. Aerial imagery – useful for evaluating actual ground conditions
 - l. Additional data layers as provided by the Department of Health and Mental Hygiene related to public health concerns

4. Planning element: Identification of appropriate natural resource mitigation actions to address unavoidable impacts. The [Watershed Resources Registry Tool](#)¹³ can be used to identify potential mitigation options for restoration and conservation of stream buffers, wetlands and upland forests. This tool has been developed by a consortium of federal and State regulatory and non-regulatory agencies, including MDE and DNR.

¹³ watershedresourcesregistry.com

SECTION IV – LOCATION RESTRICTIONS AND SETBACKS

This section addresses restrictions on the locations of well pads¹⁴, pipelines, access roads, compressor stations, and other ancillary facilities. Certain ecologically important areas, recreational areas and sources of drinking water may only be fully protected if certain activities are precluded there. Similar reasoning can be applied to the protection of cultural and historic resources, where the presence of shale gas development infrastructure will detract from the interpretative value and visitor experience. Minimizing conflict with residential and community based uses is also an important consideration in defining location restrictions. In addition to designating certain places or features themselves “off limits”, many of these resources also require a minimum setback distance to provide an additional buffer between the development activity and the resource of concern. The setback distance will vary based on the resource of concern and the nature of the disturbance. This section also describes additional avoidance, minimization and mitigation criteria and siting best practices.

A. Location Restrictions and Setbacks

UMCES-AL Report recommendations 1-E, 1-H, 1-I, 1-J, 4-A, 5-C, 5-C.1, 5-C.2, 5-C.3, 6-B, 8-F, 8-G, 9-C

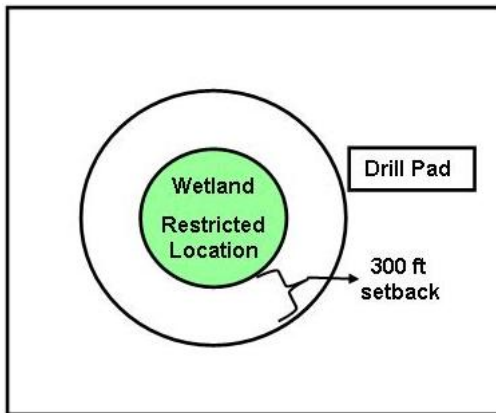
Certain location restrictions and setbacks exist in current law and regulation and, with the exception of the prohibition on locating a gas well within 2,000 feet of another gas well in the same reservoir, these will not be lessened. In addition to a statutory prohibition against drilling for gas or oil in the waters of the Chesapeake Bay, any of its tributaries, or in the Chesapeake Bay Critical Area (Md. Env. Code §14-107), these are:

Distance (feet)	From	To	Waivers	Cite
1,000	Well	The boundary of the property on which the well is to be drilled	Can be granted by the Department if a well location closer than 1,000 feet is necessary due to site constraints.	Md. Env. Code §14-112 and COMAR 26.19.01.09 C and D
2,000	Gas Well	Existing gas well in the same reservoir	Unless the Department is provided with geologic evidence of reservoir separation to warrant granting an exception	COMAR 26.19.01.09 E

¹⁴ The term “well pad” includes the area where drill rigs, pumps, engines, generators, mixers and similar equipment, fuel, pipes and chemicals are located. It does not include temporary housing and employee parking lots.

1320	Oil Well	Exiting oil well in the same reservoir	Unless the Department is provided with geologic evidence of reservoir separation to warrant granting an exception	COMAR 26.19.01.09 F
1,000	Well	A school, church, drinking water supply, wellhead protection area, or an occupied dwelling	Unless written permission of the owners is submitted with the application and approved by the Department	COMAR 26.19.01.09 G

The figure below illustrates the concept of location restrictions and setbacks that uses the UMCES-AL recommendation for aquatic habitat. The resource of concern is a wetland.



UMCES-AL has recommended that the edge of drill pad disturbance should be 300 feet or greater from the wetland habitat. The drill pad must be located outside of the restricted resource and the required setback distance.

A preliminary analysis was conducted by DNR to evaluate the effect of a subset of proposed location restrictions and setbacks on the ability to access Marcellus shale gas through horizontal drilling (Appendix D: Marcellus shale constraint analysis). The surface constraint factors selected were those which were appropriate for a coarse,

landscape scale analysis. An average drill pad size of 4 acres was assumed. Under a scenario that excluded drilling from the Accident gas storage dome and assumed an 8,000 foot horizontal drill length, approximately 94 percent of the Marcellus shale would be accessible. In an effort to be conservative, the same analysis was run using a 4,000 foot horizontal drill length, resulting in about 86 percent accessibility to the Marcellus shale formation. This assessment supports the UMCES-AL suggestion that it is reasonable to expect that shale gas resources can be broadly accessed while minimizing surface disturbance, particularly in areas with sensitive resources. Setback recommendations from the UMCES-AL Report, with the Departments' changes, are provided in Table I-2 below.

Table I-2: Setback Recommendations from UMCES-AL Report with Adjustments Recommended by the Departments			
Distance (feet)	From	To	MDE and DNR Adjustment
2,000	Surface of the ground	The target formation	2,000 vertical feet between the lowest fresh water aquifer and the target

			formation
300	Aquatic habitat (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and 100 year floodplains)	Edge of drill pad disturbance ¹⁵	450 feet ¹⁶
600	Special conservation areas (e.g., irreplaceable natural areas, wildlands)	Edge of drill pad disturbance	Agree; apply not just to drill pad locations but to all permanent surface infrastructure
300	All cultural and historical sites, State and federal parks, trails, wildlife management areas, scenic and wild rivers, and scenic byways	Edge of drill pad disturbance	Apply not just to drill pad locations but to all permanent surface infrastructure.
1,000	Mapped limestone outcrops or known caves	Borehole	Agree as to caves; for limestone outcrops, reduce to a setback of 750 feet on the downdip side
1,000	Mapped underground coal mines	Borehole	Unnecessarily restrictive; alternative approach recommended; see Section VI-E
1,320	Historic gas wells	Any portion of the borehole, including laterals	Agree
1,000	Any occupied building	Compressor stations	Agree
1,000	Any occupied building	Borehole	Change to from edge of drill pad disturbance
500	Private ground water wells	Borehole	Within 2,000 feet of a private drinking water well; except that the

¹⁵ “Edge of drill pad disturbance” means the limit of disturbance as indicated on the erosion and sediment control plan for the construction.

¹⁶ This distance shall be measured from the center of a perennial stream or from the ordinary high water mark of any river, natural or artificial lake, pond, reservoir, seep or spring, determined as conditions exist at the time of the approved CGDP.

			well pad may be located between 1,000 and 2,000 feet of a private drinking water well if the applicant demonstrates through a hydrogeologic study that the proposed well pad is not upgradient of the private drinking water well and the owner of the private drinking water well consents. Change borehole to edge of drill pad disturbance.
2,000	Public ground water wells	Borehole	a. Within 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. b. Within 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).] Change from borehole to edge of drill pad disturbance
2,000	Public surface water intakes	Borehole	Within 1,000 feet of a source water assessment area for a public water system for which a SWPA Area has been delineated. Change from borehole to edge of drill pad disturbance

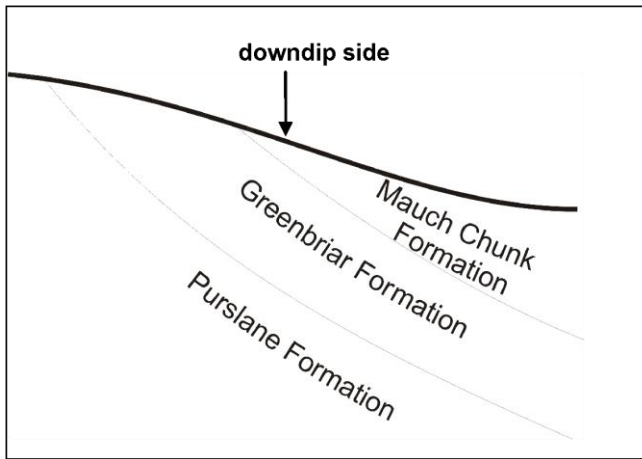
The Departments propose the following modifications and additions that were based on the subject matter expertise of the agencies.

1. Well pads shall not be constructed on land with a slope > 15 percent before grading. This was recommended in the report, but not included as a key recommendation.
2. Setback distances may be expanded on a case by case basis if the area includes steep slopes or highly erodible soils.
3. The setback distance from aquatic habitat (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and 100 year floodplains) has been expanded to 450 feet. Based on additional literature review documented in Appendix G, the setback was expanded to provide the necessary level of protection for biodiversity (with a focus

on aquatic biodiversity), ensure sufficient corridor width needed for terrestrial wildlife movement and forest interior-dwelling bird species, and reduce the visual, noise, and light impacts of gas extraction operations in close proximity to aquatic habitats.

4. The setback from a spring that is used as the source of domestic drinking water by the residents of the property on which the spring is located, measured from spring to the edge of the well pad, shall extend to all lands at an elevation equal to or greater than the spring discharge elevation, but not to exceed 2,500 feet unless a delineation of the recharge area prepared by a registered geologist, with a report and data supporting an alternate area, is submitted to the Department and the Department approves an alternative area.

5. The restrictions for setbacks from limestone outcrops to the borehole has been expanded to 750 feet (from the recommended 500 feet in the draft report) and to apply only on the downdip side of the formation.



There is no need to adhere to setbacks on the updip side because the limestone formation – the Greenbriar – will not be encountered (see figure to left). This setback recommendation was established to avoid karst features. However, the Maryland Geological Survey states that most limestone in Garrett County is not karst, but when these features do occur, they rarely penetrate below 100 – 200 feet from the surface. In Garrett

County, these formations generally dip at 15-20 degrees, while the beds in Allegany County dip at steeper angles. Using a 200 foot depth for potential karst development and a 15 degree dip as a conservative estimate, a 750 foot setback on the downdip side of the limestone outcrop would be sufficiently protective. The State originally proposed a 500 ft setback which was based on the steeper dip angles in Allegany County. This was expanded to 750 ft upon consideration of the dip angles in Garrett County.

6. Setbacks for known and discovered caves should remain at 1000 feet because of the biological resource sensitivity and the potential for ground water contamination.

7. Restrictions for setbacks from mapped underground coal mines to the borehole are modified. MDE’s mining program notes that Maryland’s deep coal mines may cover thousands of acres, are only several hundred feet deep, and can be safely cased through, particularly if pilot holes are drilled to identify these features and drilling processes are modified to address the known hazards. A setback of 1000 feet is unnecessarily restrictive. Instead the Departments recommend pre-drill planning as an alternative which involves careful site evaluation and pilot hole investigations. See Section VI-E for a description on pre-drill planning.

8. All surface disturbance for pads, roads, pipelines, ponds and other ancillary infrastructure will be prohibited on State owned land, unless DNR grants permission.

9. To more fully protect sources of drinking water, a well pad cannot be located:
 - a. Within 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.
 - b. Within 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).)
 - c. Within 2,000 feet of a private drinking water well; except that the well pad may be located between 1,000 and 2,000 feet of a private drinking water well if the applicant demonstrates through a hydrogeologic study that the proposed well pad is not upgradient of the private drinking water well and the owner of the private drinking water well consents.
 - d. Within the watersheds of any of the following reservoirs:
 - i. Broadford Lake
 - ii. Piney Reservoir
 - iii. Savage Reservoir

10. Drill pad location restrictions and setbacks listed in Table 1-1 have been extended to all gas development activities resulting in permanent surface alteration that would negatively impact natural, cultural and historic resources. This includes permanent roads, compressor stations, separator facilities and other infrastructure needs. This expansion applies to aquatic habitat, special conservation areas, cultural and historical sites, State and federal parks and forests, trails, wildlife management areas, wild and scenic rivers and scenic byways.

11. DNR will develop new maps of public outdoor recreational use areas to consider whether additional recreational setbacks are warranted and to inform mitigation measures for minimizing public use conflicts. DNR conducted a participatory GIS workshop in November of 2013 to develop these new maps, focusing on the recreational amenities of lands in Garrett and Allegany Counties that co-occur with the Marcellus shale extraction region.

The proposed recreational setback from Marcellus shale gas infrastructure is a minimum of 300 feet with additional setback considerations for noise, visual impacts and public safety. Maryland has a number of well-developed and nationally-recognized networks of scenic and historic byways and hiking and water trails that provide opportunities for the public to experience nature, cultural and historical features and the outdoors through unique vistas and long-distance travel routes. The location and features that make these routes unique (e.g. vistas, through-trail hikes, canopy cover) should be considered during setback discussions. Additional factors will include hunting and fishing activities, light, odor and other issues that would affect public use and enjoyment of these resources. A more detailed discussion of these issues and concerns is provided in Appendix E: Marcellus Shale and Recreational & Aesthetic Resources in Western Maryland. The

participatory GIS workshop was conducted with facility managers, friends groups, frequent visitors, and other stakeholders. The maps generated from these discussions and workshops will be included in the Shale Gas Development Toolbox and used to inform comprehensive gas development plans, setback considerations, mitigation measures and timing of shale gas development activities.

12. For good cause shown and with the consent of the landowner protected by the setback, MDE may approve exceptions to the setback requirements.

B. Siting Best Practices

UMCES-AL Report recommendations 3-B, 4-D, 5-A.2, 6-J.2, 6-J.4, 8-C, 8-D, 8-H, 9-G, 9-H, 10-A, 10-C, 10-D

This section also includes best practices recommended for siting pipelines, access roads and other supporting infrastructure. The Departments generally accept the proposed siting best practices with the following modifications and additions.

1. Forest mitigation that is required to meet a no-net-loss of forest standard will be evaluated differently based on whether the loss is temporary or permanent.
2. Site-specific viewshed analysis should be conducted (as recommended by UMCES-AL), but temporary and permanent impacts will be evaluated differently.
3. Conservation of high value forest land through easements or fee-simple acquisitions should be considered as an additional mitigation option for implementing the no-net-loss of forest recommendation, particularly since reforestation options in western Maryland locations may be limited. Conservation banking may also be an additional mechanism to meet forest conservation mitigation.
4. DNR will provide additional GIS conservation planning data layers and guidance for avoiding, minimizing and mitigating impact to aquatic and terrestrial high priority conservation areas. These data layers will be included in the Shale Gas Development Toolbox described in Section III-E.
5. Stream crossings will avoid impact to brook trout spawning beds.
6. Operations, water withdrawals and infrastructure siting should avoid thermal impacts to cold water streams.

The setback and other recommendations provide a high level of protection to Tier II waters from MSGD activities. MDE will consider whether additional anti-degradation protections are necessary for MSGD when it revises its anti-degradation regulations.

SECTION V – PLAN FOR EACH WELL

UMCES-AL Report recommendations 1-A, 3-A, 4-B

For each well, the applicant for a drilling permit shall prepare and submit to MDE, as part of the application, a plan for construction and operation that meets or exceeds the standards and/or individual planning requirements for Engineering, Design and Environmental Controls set forth in Section VI. 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. The Department will clarify in the application form, or instructions for that form, the type of information and level of detail that must be addressed in the application for an individual well permit. The plan must address, at a minimum,

1. Completing the Environmental Assessment

This effort includes all environmental assessment baseline monitoring and site characterization required as a prerequisite for issuing individual well permits. These are activities that would be initiated after the CGDP has been approved and require site-specific, field scale assessment and monitoring.

2. Constructing the pad, containment structures, access roads and other ancillary facilities
3. Method of providing power to equipment
4. Acquisition of water
5. Evaluation of potential flow zones
6. Identification and evaluation of shallow and deep hazards
7. Pore pressure/fracture gradient/drilling fluid weight
8. Monitoring and maintaining wellbore stability
9. Lost circulation
10. Casing
11. Cementing
12. Drilling fluids
13. Wellbore hydraulics
14. Barrier design
15. Integrity and pressure testing
16. Blow out protection

17. Contingency planning
18. Communications plan, including communication with contractors and subcontractors and transfer of information upon shift change
19. Site security
20. Noise
21. Storage, treatment and disposal of water, wastewater, fuel and chemicals
22. Road construction and maintenance
23. Transportation planning, including the identification of routes to be traveled in Maryland by heavy duty trucks and tractor trailers coming to or leaving the pad site
24. Spill prevention, control and countermeasures, and emergency response
25. Invasive species
26. Waste handling, treatment and disposal
27. Monitoring during well production to detect well problems and failure of casing or cement
28. Reclamation
29. Site specific visual impact assessment and mitigation

The applicant will be required to notify the owners of any property within 2,500 feet that an application has been filed.

A suggestion has been made by some Commissioners that there be a formal process by which other State and local government agencies could review and comment on the application for an individual well permit. Because interagency issues will relate principally to the location of the well pad, access roads, pipelines and other infrastructure, review by other State and local government agencies would be more appropriate and effective at the time of the CGDP, not the individual well permit. The Departments recommend that the appropriate staff from specific agencies be invited to participate in the CGDP development. The Departments plan to address coordination with local government agencies on specific topics, such as transportation planning and emergency response, through the standards set out in Section VI.

In the event that an application is made for an exploratory wells before a CGDP has been submitted and approved, MDE will notify relevant State agencies and the County and municipality in which the proposed exploratory well is to be located and provide an opportunity to review the application and comment. Relevant State agencies will include DNR and the Maryland Departments of Agriculture, Planning, and Health and Mental Hygiene.

SECTION VI – ENGINEERING, DESIGN AND ENVIRONMENTAL CONTROLS AND STANDARDS

The standards in this section do not preclude the use of new and innovative technologies that provide greater protection of public health, the environmental and natural resources. Practices used in shale gas development continue to evolve and improve. Exceptions to these requirements will be considered if the new technology can be demonstrated to assure equal or greater protection.

A. Site Construction and Sediment and Erosion Control

UMCES-AL Report recommendations 4-E, 4-F, 4-G, 4-I, 5-B, 5-B.1, 6-G, 6-J, 6-J.1, 6-J, 6-K, 9-F

The proper construction of drilling pads, roads, pipelines, tanks, pits and ponds, roads, and ancillary equipment is critical for eliminating or minimizing the risk of release of pollutants to the environment from spills, accidents, and runoff of contaminated stormwater. Current Maryland statutes and regulations on oil and gas wells are nearly silent on design and construction requirements, except for pits and tanks.¹⁷ The regulations require an approved stormwater management plan and sediment and erosion control plan, but do not establish any requirements specific to oil and gas operations.¹⁸ As these plans are written to address the requirements of shale gas development, training of staff who review and approval the plan may be required.

1. The pad

The pad is the center of activity during drilling and HVHF. 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. The “well pad” includes the area where drill rigs, pumps, engines, generators, mixers and similar equipment, fuel, pipes, chemicals and wastes are located. It excludes temporary housing and employee parking lots. Pollutants released¹⁹ on the pad could enter the environment by infiltrating through the pad, running off the pad, or being washed from the pad by precipitation. The UMCES-AL Report recommended closed loop drilling systems on “zero-discharge” pads, containment of stormwater from the pad, and storage of all liquids (except fresh water) in watertight, closed tanks inside secondary containment. The Departments agree.

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

¹⁷ COMAR 26.19.01.10 J through K.

¹⁸ COMAR 26.19.01.06C (12) and (13).

¹⁹ Airborne releases are considered separately.

by an impermeable berm such that the pad can contain at least the volume of 4.0 inches of rainfall within a 24 hour period. 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.

2. Tanks and containers

Tanks shall be above ground, constructed of metal or other material compatible with the contents, and lined if necessary to protect the metal from corrosion from the contents. Except for tanks used in a closed loop system for managing drilling fluid and cuttings, which may be open to the atmosphere, tanks shall be closed and equipped with pollution control equipment specified in other sections of this report. Tanks and containers shall 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.

3. Pits and Ponds

The UMCES-AL Report does not make recommendations for the construction of pits and ponds, but recommends that they should be used only to collect or store fresh water; all other material shall be stored in tanks. The Departments agree.

Current Maryland regulations require pits and ponds shall (a) have at least 2 feet of freeboard at all times; (b) be at least 1 foot above the ground water table; (c) be impermeable; (d) allow no liquid or solid discharge of any kind into the waters of the State; and (e) provide for diverting surface runoff away from the pit or pond. Dikes associated with pits must be constructed and maintained in accordance with standards and specifications for soil and erosion sediment control. In addition they must be constructed of compacted material, free of trees and other organic material, and essentially free of rocks or any other material which could affect their structural integrity; and the dikes must be maintained with a slope that will preserve their structural integrity; COMAR 26.19.01.10J and K. The Departments judge that the current regulations are sufficient for fresh water storage.

4. Pipelines

Gathering lines are pipelines that bring gas to a central facility or transmission line. Transmission lines are interstate lines that transport gas long distances. The federal and state governments share responsibility for gas pipelines. State and local laws address pipeline placement as a construction activity that must comply with erosion and sediment control plans and stormwater management. In addition, if pipelines cross wetlands or waterways, additional permits may be required.

The United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), has overall regulatory responsibility for hazardous liquid and gas pipelines in the United States that fall under

its jurisdiction. OPS regulates and inspects hazardous liquid and gas interstate operators in Maryland. Through certification by OPS, the State of Maryland regulates and inspects the operators having intrastate gas and liquid pipelines. This work is performed by the Pipeline Safety Division of the Maryland Public Service Commission.

Onshore natural gas gathering lines are classified by the federal government based upon the number of buildings intended for human occupancy that lie within 220 yards on either side of the centerline of any continuous one mile length of pipeline. If there are fewer than 10 such buildings, the gathering lines are not federally regulated. They are sometimes referred to as “rural gas gathering lines” In Maryland, the Pipeline Safety Division of the Maryland Public Service Commission (PSC) regulates and inspects intrastate gas and liquid pipelines. It appears that the PSC has not established any standards for the location, materials, construction or testing of gathering lines beyond the federal standards..

In the past, gathering lines were generally small diameter and did not operate under high pressure. PHMSA has recognized that lines being put into service in shale plays like the Marcellus are generally of much larger diameter and operating at higher pressure than traditional rural gas gathering lines, increasing the concern for safety of the environment and people near operations. Because they are unregulated, the PHMSA had limited information about pipeline construction quality, maintenance practices, location and pipeline integrity management. It is in the process of collecting new information about gathering pipelines in an effort to better understand the risks they may now pose to people and the environment. If the data indicate a need, PHMSA may establish new, safety requirements for large-diameter, high-pressure gas gathering lines in rural locations.

In the absence of existing federal or Maryland regulation of rural gathering lines, the Departments recommend that, as a best practice, except for those oil and/or natural gas pipelines covered by the Hazardous Materials Transportation Act (49 U.S.C. sections 1802 *et seq.*) or the Natural Gas Pipeline Safety Act (49 U.S.C. sections 1671 *et seq.*), all pipelines utilized in the actual drilling or operation of oil and/or natural gas wells, the producing of oil and/or natural gas wells, and the transportation of oil and gas, shall comply with the following standards for material and construction:

- 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.

5. Road Construction

The UMCES-AL Report makes several recommendations about roads. Wherever possible, existing roads should be used. Where new private road construction for Marcellus shale activities in Maryland is necessary, it should follow guidelines issued by the Pennsylvania Department of Conservation and Natural Resources. The guidelines: (1) recommend utilizing materials and designs (*e.g.*, crowning, elimination of ditches) that encourage sheet flow as the preferred drainage method for any new construction or upgrade of existing gravel roadways; (2) provide specific recommendations about aggregate depth, type, and placement; and (3) promote the use of geotextiles as a way of reducing rutting and maintaining sub-base stability. Erosion should be controlled and damage to environmentally sensitive areas should be avoided. The authors opine that one of the best ways to minimize the risk of road failures is to selectively schedule hauling operations to avoid or minimize traffic during the spring thaw and other wet weather periods. They further recommend that where stream crossings are unavoidable, the design incorporate bridges or arched culverts to minimize disturbance of streambeds.

The Departments agree that roads constructed by private parties for access to gas exploration and production facilities should avoid adverse environmental impacts and minimize those that cannot be avoided. The location of roads will be evaluated during the review of the Comprehensive Development Plan. Sediment and erosion control plans and stormwater management plans will provide assurance that erosion will be controlled.

The UMCES-AL Report recommended the standards used by the Pennsylvania Department of Conservation and Natural Resources, Bureau of Forestry, for roads in leased State forest land. These standards are contained in [Guidelines for Administering Oil and Gas Activity on State Forest Lands](#).²⁰ The Bureau of Forestry works closely with The Pennsylvania State University's [Center for Dirt and Gravel Road Studies](#)²¹ to identify and adopt best practices for road maintenance and construction. The Center makes a large amount of information about unpaved roads available on its website, including technical bulletins. The Departments recommend that 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.

6. Ancillary equipment

Ancillary equipment includes gathering and boosting stations, glycol dehydrators and compressor stations. A gathering and boosting station collects gas from multiples wells and moves it toward the natural gas processing plant. Glycol dehydrators are used to remove water from natural gas to protect the systems from corrosion and hydrate formation. Compressor stations are placed along pipelines as necessary to increase pressure and keep the gas moving. The location of compressors will be addressed in the CGDP. Ancillary equipment is addressed in Section VI J and N (Air Emissions and Noise).

B. Transportation Planning

UMCES-AL Report recommendations 7-A, 7-D, 7-D.1, 7-D.2, 8-E, 9-A.4, 9-E, 9-E.1

²⁰ http://www.dcnr.state.pa.us/cs/groups/public/documents/document/dcnr_004055.pdf

²¹ www.dirtandgravel.psu.edu/

In addition to road construction standards, timing of transportation activities and addressing road damage are necessary elements of transportation planning. The State and most counties have existing programs to allow for emergency transport of heavy or oversized equipment during off-hour periods. The Departments accept the proposed transportation planning recommendations with the following modifications and additions to minimize use conflicts and provide adequate mitigation for road damage.

State public land managers should coordinate the timing of oil and gas activities with the operator to avoid public conflict and to minimize damage to roads on public lands. Public land managers should consider suspending activities requiring heavy trucking during:

1. Periods of heavy public use such as hunting season or trout season
2. Weather conditions that make the roads impassable
3. Traditionally wet periods when road damage is most probable
4. During the spring frost breakup

Note: Trucking should be closely monitored during high-use and wet periods if it is not possible to suspend activities.

Applicants must coordinate with county and/or municipal offices to avoid truck traffic under the following conditions:

1. During times of school bus transport of children to and from school locations.
7. During public events and festivals

Local jurisdictions are encouraged to develop adequate transportation plans.

Heavy equipment should be moved by rail, if available, to the maximum extent practicable to protect road systems and prevent accidents.

All trucks, tankers and dump trucks transporting liquid or solid wastes must be fitted with GPS tracking systems to help adjust transportation plans and identify responsible parties in the case of accidents/spills.

Applicants shall be required to enter into agreements 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.

C. Water

UMCES-AL Report recommendations 4-G, 4-J, 6-H.1, 6-H.2

1. Storage

The UMCES-AL Report recommended that the Maryland regulations should specifically address water storage, that impoundments may be used for storing freshwater, and that temporary pipelines should be considered instead of trucks for transporting water. The Departments agree that only freshwater should be stored in impoundments and would permit either centralized freshwater impoundments or impoundments serving a single well pad, provided the impoundment meets standards for safe construction (refer to Pits

and Ponds, above). Applicants for permits are encouraged to propose using temporary pipelines for the transfer of fresh water to a drill site.

2. Water withdrawal

The UMCES-AL Report recommends that Maryland revise its oil and gas permitting regulations to explicitly address water withdrawal issues. In particular, they recommend a quantitative analysis of acceptable water withdrawals to ensure that all users of the resource are protected and that water withdrawal should occur only from the region's large rivers and perhaps from some reservoirs. In addition, the authors recommend that precautions be taken to avoid the introduction of invasive species. For example, they recommend an analysis of any invasive species that may be present in the source water and power washing of the withdrawal equipment before it is removed from the withdrawal site.

The Departments agree that practices are necessary to control invasive species. They are addressed in Section VI O (Invasive Species). The Departments do not see a need to add water appropriation provisions in MDE's oil and gas regulations because current Maryland laws and regulations protect other users of the water resource and the resource itself.

The Maryland legislature has determined that the appropriation or use of surface or ground water must be controlled in order to conserve, protect, and use water resources of the State in the best interests of the people of Maryland. This control provides for the greatest possible use of waters in the State, while protecting the State's valuable water supply resources from mismanagement, abuse, or overuse. Private property owners have the right to make reasonable use of the waters of the State which cross or are adjacent to their land. For the benefit of the public, the Department acts as the State's trustee of its water resources. Maryland follows the reasonable use doctrine to determine a person's right to appropriate or use surface or ground water. A ground water appropriation or use permit or a surface water appropriation or use permit issued by MDE authorizes the permittee to make reasonable use of the waters of the State without unreasonable interference with other persons also attempting to make reasonable use of water. The permittee may not unreasonably harm the water resources of the State. COMAR 26.17.06.02.

Current Maryland statutes and regulations on water withdrawal, with certain exceptions not relevant here, require MDE approval and issuance of an appropriation permit before a person can withdraw any surface water, or more than 5,000 gallons per day (gpd) of ground water as an annual average. Appropriation requests for an annual average withdrawal of more than 10,000 gpd (as a new request or increase) may be required to perform aquifer testing and other technical analyses. All applicants proposing a new use of increase of 10,000 gpd are required to include certified notification of contiguous property owners and certification of compliance with the State plumbing code and requirements for water conservation technology. In addition, requests for an annual average withdrawal of more than 10,000 gpd as a new request or increase are advertised for a public information hearing.

Because the thresholds for requiring a permit are low, it is unlikely that anyone could obtain a sufficient amount of water for HVHF without first obtaining a water

appropriation permit. The Departments believe that the substantive criteria for evaluating applications for water appropriation are adequate to address water withdrawals for Marcellus shale drilling and HVHF. These criteria are set forth in COMAR 26.17.06.05 and include impact on other users and the waters of the State, and the aggregate changes and cumulative impact that the particular request and future appropriations in an area may have on the waters of the State. The Department of the Environment has the authority to include protective provisions in permits. COMAR 26.17.06.06.

3. Water reuse

This topic is further discussed under Wastewater Treatment and Disposal, below. The UMCES-AL Report recommended that Maryland should include “a very strong preference” for onsite recycling of wastewater over treatment at a centralized facility, because this would decrease truck transport and associated impacts. The Departments agree.

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.

D. Chemical Disclosure

UMCES-AL Report recommendations 4-H

The recommendations about disclosure of chemicals in the UMCES-AL Report related specifically to response to chemical emergencies, and are addressed under the heading of Spill Prevention, Control and Countermeasures, and Emergency Response.

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 HVHF. Many gas operators voluntarily disclose the chemicals they use, after the fact, although some chemicals are not specifically identified because they are claimed to be trade secrets. The Departments agree that it would be desirable for MDE to review the chemicals before they are used. The Departments therefore propose the following standards for chemical disclosure.

The Departments will require the disclosure 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.

The permittee will be required to provide a complete list (Complete List) of chemical names, CAS²² numbers, and concentrations of every chemical constituent of every commercial chemical product brought to the site. If a claim is made that the composition

²² A CAS number is a unique number assigned by the Chemical Abstract Service to each chemical entity. If the chemical has not been assigned a CAS, the permittee shall provide the name of the chemical using the conventions of the International Union of Pure and Applied Physics. If the constituent is a natural material whose constituents have not been fully characterized, such as walnut shells used as a proppant, such a description such as “crushed walnut shells” shall be accepted.

of a product is a trade secret, the permittee must 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. MDE will retain the list or lists in the permit file. 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 therefore the posting may be different.

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 (SDS, formerly called Material Safety Data Sheets) for all products that contain one or more OSHA hazardous chemicals.

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, 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. 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.

E. Drilling

1. Use of electricity from the grid

UMCES-AL Report recommendations 2-B, 9-D.-1. (Additional recommendations about the use of electricity are addressed below in section N., Noise.)

The UMCES-AL Report suggests that Maryland consider mandating electrically-powered equipment wherever line power is available (or could be made readily available) from the grid. The Departments agree that this practice would reduce air emissions. The use of propane or natural gas to power motors and pumps should be encouraged if electricity from the grid is not available.

There are multiple factors which would favor the use of one power source or fuel over another, including the land disturbance necessary to bring power to the site, the greenhouse gas footprint of electricity supplies and the loss of electricity resulting from electric power transmission. The Departments will require that applicants provide a power plan that results in the lowest practicable impact from the choice of energy source.

2. Initiation of drilling

UMCES-AL Report recommendations 5-D.1, 8-I, 9-D.2

The UMCES-AL Report recommended that drilling should avoid times of peak outdoor recreational periods such as holiday weekends, first day of trout season, and during sensitive wildlife migratory or mating seasons. In addition, the report recommended that hours and times of operation be restricted to avoid or minimize conflicts with the public.

The Departments agree that these recommendations would offer a high level of protection to these activities; however, the Departments acknowledge that once drilling and fracturing operations have begun, it is generally not safe to halt activities. For this reason, these restrictions can only be applied to the initiation of a drilling or fracturing operation

or other activities that could be planned in advance or temporarily suspended. The specific restrictions should be included as a condition in the well permit.

3. Pilot hole

The UMCES-AL Report notes the importance of avoiding drilling through large underground voids (*e.g.*, caverns, caves, mine workings, abandoned wells) because these voids increase the risk of losing fluid circulation during drilling and complicate the cementing process. The principal recommendations for avoiding these dangers involve setback requirements; in addition the authors suggest that Maryland also consider mandating the use of surface geophysical techniques (*e.g.*, seismic surveys) or “pilot hole” boring as part of an exploration/drilling hazard assessment program that is aimed at identifying other subsurface MSGD hazards that are not well mapped.

The Departments agree that drilling a pilot hole is an excellent way of identifying geological features, underground voids, gas or fluid bearing formations, and the lowest fresh water aquifer in the immediate vicinity of the proposed bore hole. One pilot hole investigation will be required for every pad to investigate the geology and determine all strata where liquid or gaseous flow occurs. The Departments will also require that the CGDP include a geological investigation by the applicant of the area covered by the CGDP. This investigation serves several purposes, including identifying underground voids. The applicant will be required to submit the survey data in a report to the State. If the applicant asserts that the geological information is confidential business information, the State will not release the information to the public for a period of three years.

Where underground mining is suspected to have occurred within 500 feet of the prospective borehole, based on a review of available records, the applicant shall select, if possible, drill hole locations that avoid all mine voids and assures lateral support of drill holes during drilling and casings during well construction. If such locations cannot be found, voids must be filled or isolated with multiple concentric strings of casing and cement.

4. Drilling fluids and cuttings

UMCES-AL Report recommendation 6-G

The UMCES-AL Report notes that high pressure air can be used rather than water as the “fluid” to bring rock fragments to the surface and cool the drill bit. When subsurface pressures are high, however, it is necessary to use drilling mud. Drilling mud can use water or other liquid or gaseous fluids as a base. Water-based drilling mud is a mixture of water, weighting agents, clay, polymers, surfactants and other chemicals. During horizontal drilling, mud powers and cools the downhole motor and bit, operates the navigational tools, provides stability to the borehole, and removes cuttings. The material returned to the surface is a mixture of drilling mud and native rock. The drilling mud can be reused. Open pit systems have been used in the past to manage the returned material, but the UMCES-AL Report recommends that closed-loop drilling systems be required. The Departments agree.

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. Only additives suitable for drilling through potable water supplies can be used while drilling these intervals. Below the cemented surface casing that isolates the deepest stratum bearing fresh water, additives other than those suitable for drilling through potable water can be used if approved by the Department.

A best practice for managing cuttings is to contain the drilling fluid, the returned drilling fluid and the cuttings in a closed loop system with secondary containment on the well pad. That means that separating the cuttings from the returned drilling fluid must be done in tanks or containers, and that any storage of these materials would also have to be in tanks or containers. The secondary containment could be the zero-discharge well pad itself or another impermeable containment system, provided the secondary containment is capable of holding the total volume of the largest storage container or tank located within the area enclosed by the containment structure.

Due to the potential for cuttings from shale formations to contain Naturally Occurring Radioactive Material, the UMCES-AL Report recommends that onsite disposal be prohibited, that the cuttings be tested for radioactivity, and that they be disposed of in a landfill only if the testing indicates no significant elevation above background levels.

The Departments agree that the cuttings and drilling mud, as well as flowback, produced water, residue from treatment of flowback and produced water, and any equipment where scaling or sludge is likely to occur should be tested for radioactivity and disposed of in accordance with law. The Departments are evaluating whether to impose a limit on the level of radioactivity in cuttings and drilling mud that may be disposed of in municipal landfills. The Departments recommend that cuttings and drilling mud also be tested for 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.

5. Open hole logging

Open hole logging provides important information about the formations encountered and can be used to optimize the well design and drilling operations. Lithology can be determined from gamma ray logs, the presence of hydrocarbons by electrical resistivity logs, liquid-filled porosity by neutron porosity logs and bulk density by density logs. Borehole caliper logs assist in calculating the amount of cement needed. Mud logging can be used to determine the concentration of natural gas being brought to the surface with the drilling mud. The UMCES-AL Report does not make a specific recommendation about open hole logging, but states that “The best practice would utilize modern open-hole well logging methods to help fine tune casing placement and characterize flow and hydrocarbon zones, [and] perhaps mud logging to determine levels of hydrocarbons in real-time during drilling....” (UMCES-AL at page 3-11)

Without specifying the methods to be used, current Maryland regulations require the submission of a well completion report that must include, among other things,

- (a) Depth at which any fresh water inflow was encountered;
- (b) Lithology of penetrated strata, including color;
- (c) Total depth of the well;

- (d) A record of all commercial and noncommercial oil and gas encountered, including depths, tests, and measurements;
 - (e) A record of all salt-water inflows;
 - (f) Generalized core descriptions, including:
 - (1) The type and depth of sample;
 - (2) Indications of oil, water, or gas;
 - (3) Estimates of porosity and permeability; and
 - (4) Percent recovery; and
 - (g) A copy of all electric, radiation, sonic, caliper, directional, and any other type of logs run in the well.
- COMAR 26.19.01.10 V.

To obtain this mandatory data, a driller would have to employ all of the techniques mentioned above with the exception of caliper logs and mud logging. The caliper logs would provide information to inform decisions about casing, centralizers, and cement. For this reason, we recommend that borehole caliper logs be performed.

F. Casing and Cement

UMCES-AL Report recommendations 3-C, 3-D, 3-E, 7-A.2

1. Requirements for casing and cement

Before beginning to drill a gas well, the operator must receive approval from MDE of a plan that describes:

- a. how the a stable borehole will be drilled with minimal rugosity;²³
- b. how complete removal of drilling fluid will be accomplished;
- c. how the cement system design addresses challenges to zonal isolation;
- d. how other factors that could interfere with the proper placement of the cement around the casing will be addressed; and
- e. how the casing and cement will assure durability throughout the well life cycle.

This plan can be submitted with the permit application, but the permittee must review the plan in light of information obtained from the pilot hole drilled for that well pad, and certify to the Department that the plan utilizes the right practices and materials for the specific situation to assure zonal isolation. 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. Adherence to the drilling, casing and cementing plan, as well as integrity testing will be a condition of the permit.

²³ Rugosity refers to the roughness of a borehole wall. Rugosity can be observed on caliper logs and image logs Source: Schlumberger Oil Glossary. High rugosity can make it more difficult to remove the drilling fluid and achieve zonal isolation with cement.

Before drilling below the first casing string, the owner shall either crown the location around the wellbore to divert fluids, or construct a liquid-tight collar at least three feet in diameter to prevent surface infiltration of fluids adjacent to the wellbore.

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.

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.”

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.

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

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.

2. Isolation

The casing and cement provide zonal isolation between the well and all other subsurface formations. Liners and tiebacks may be used, provided the exposed casing meets all regulatory requirements for casing. Surface casing shall be run and permanently cemented from the surface to a depth at least 100 feet below the deepest known stratum bearing fresh water, or the deepest known workable coal, whichever is deeper. Intermediate casing, if used, must isolate all fluid bearing zones through which it passes. 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 500 feet above the uppermost fluid bearing formation not already isolated by surface casing or intermediate casing, whichever is shallower. In this way, casing and cement will isolate all fluid-bearing (gas and liquid) formations through which the

borehole passes before reaching the target formation, but it will be possible to monitor annular pressure, which provides the operator with valuable information.

3. Cased-hole logging, Integrity testing and Pressure testing

Cased-hole logging occurs after the casing is cemented. The objectives are to determine the exact location of the casing, the casing collars, and the integrity of the cement job. Common methods of assessing the integrity of the cemented casing are cement bond logging and gamma ray logging. According to the UMCES-AL Report, newer testing equipment can perform a segmented radial cement bond logging (SRCBL), which can determine the presence and locations of small channels in the cement that could indicate poor zonal isolation.

The UMCES-AL Report recommended Maryland should consider amending its regulations to require SRCBL (or equivalent casing integrity testing) and other types of logging (*i.e.*, neutron logging) as part of a cased-hole program. The Departments agree.

SRCBL will be required for all casing strings from the surface casing and below along the portions that are cemented. This can be supplemented by other methods, including omnidirectional cement bond logging and observations and measurements during cementing.

An applicant for a drilling permit will be required to provide a plan for integrity and pressure testing for approval by MDE. If there is evidence of inadequate casing integrity or cement integrity, the Department must be notified and remedial action proposed. 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. Integrity testing will be required when a well is re-fractured. All integrity test results must be reported to MDE.

G. Blowout Prevention

UMCES-A: Report recommendation 3-F

A blowout preventer is a mechanical device that can close or seal a wellbore if pressure in the well cannot be contained. Without a blowout preventer, extreme erratic pressures and uncontrolled flow encountered during drilling could cause a blowout -- the uncontrolled release of liquid and gas from the well and the ejection of casing, tools and drilling equipment from the well. The blowout preventer is installed at the top of the surface casing. Depending on the design, a blowout preventer may close over an open wellbore, seal around tubular components, or shear through the casing to seal the well.

The UMCES-AL Report recommended that Maryland require the use of blowout prevention equipment with two or more redundant mechanisms. The Departments agree and will make this a requirement. Existing COMAR regulations already require the blowout prevention equipment must be tested to a pressure in excess of that which may be expected at the production casing point before drilling the plug on the surface casing; and penetrating the target formation. The Departments will require that 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. The blow out preventer must be tested on a weekly basis.

H. Hydraulic Fracturing

UMCES-AL Report recommendation 3-G

The UMCES-AL Report recommended that hydraulic fracturing should avoid times of peak outdoor recreational periods such as holiday weekends, first day of trout season, and during sensitive wildlife migratory or mating seasons.

The Departments accept the proposed limitation on hydraulic fracturing; however, the State realizes that it is unsafe to halt some operations before they are concluded. Except for activities that can be temporarily suspended, avoidance of these times must therefore be considered when operations are planned. In addition, if a well pad is not located in a place likely to adversely impact the peak outdoor recreational activities, this limitation will not apply.

The UMCES-AL Report recommended that tiltmeter or microseismic surveys be done to characterize the Marcellus shale across the region. The Departments will require that a tiltmeter or microseismic survey shall be performed by the permittee 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.

Diesel fuel shall not be used in hydraulic fracturing fluids. The Departments encourage companies to adopt innovative technology for well development that does not require large amounts of water or chemicals if the technology becomes practical. In all cases, companies should use additives with the least toxicity available.

I. Flowback and Produced Water

This topic is further discussed under Wastewater Treatment and Disposal, below.

Flowback and produced water shall be handled in a closed loop system of tanks and containers at the pad site. Flowback and produced water may not be stored in surface impoundments or ponds.

J. Air Emissions

UMCES-AL Report recommendations 2-B

On August 16, 2012, EPA published a final rule in the Federal Register establishing New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) for the oil and gas sector. EPA's final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, along with requirements for several other sources of pollution in the oil and gas industry that had not previously been regulated at the federal level. These include requirements to reduce VOCs and air toxics from new and modified compressors, pneumatic controllers, storage vessels at gathering and boosting stations, and glycol dehydrators. EPA is allowing a phased approach to comply with new requirements because of comments indicating that sufficient equipment would not be available by the proposed effective date. By January 1, 2015, however, all sources must conduct green completions.

The Departments propose to require that new facilities in Maryland meet these federal standards upon startup. In addition, the Departments recommend additional measures for reducing air emission.

1. Green Completion or Reduced Emissions Completion

Green completion shall be achieved on all gas wells drilled in Maryland. In green completions, gas and hydrocarbon liquids are physically separated from other fluids and delivered directly into equipment that holds or transports the hydrocarbons for productive use. Reduced Emissions Completions shall be required for re-fracturing.

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 permit²⁴ for exploration only, lack of a pipeline connection

2. Flaring

When flaring is permitted during well completion, re-completions or workovers²⁵ 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.

3. Electricity from the grid

Refer to Section VI.-E.1 on the use of electricity to support drilling operations.

4. 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).
- 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

²⁴ 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.

²⁵ 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.

model years, which include a combined NO_x 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.)

5. Storage tanks

EPA recently updated the 2012 standards for storage tanks. 78 Fed. Reg. 58416 (September 23, 2013). The Departments propose to require that all new natural gas operations in Maryland meet these standards upon startup.

6. Top-down BAT

The Department of the Environment intends to require top-down Best Available Technology (BAT) for the control of air emissions. This 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. BAT emissions control technology will be mandatory for workovers. MDE will analyze top-down BAT demonstrations from applicants and approve the applicants BAT determination before a permit is issued. This builds on the EPA STAR program, and therefore a separate requirement to participate in this voluntary EPA program is not needed. MDE will also require a rigorous leak detection and repair program.

MDE is considering whether it is feasible to require permittees to estimate the remaining methane emissions and offset them with greenhouse gas credits. If this occurs, the permittees will have to estimate and report emissions to the State annually

K. Waste and Wastewater Treatment and Disposal

UMCES-AL Report recommendations 4-J, 4-K

Wastes produced at well sites include cuttings, spent drilling muds, and other solid wastes. 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:

1. Underground injection in regulated Class II injection wells
2. Pretreatment, followed by further treatment by a sewage treatment plant
3. Evaporation/crystallization
4. Recycling.

Operators have been moving toward recycling of gas development wastewaters, and reusing them for hydraulic fracturing. This is the most environmentally sound method, and the UMCES-AL Report recommends that Maryland establish a goal of 100 percent recycling, with a preference for onsite recycling rather than shipment to a central treatment plant. The Departments recommend 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.

The UMCES-AL Report also recommends that Maryland should not allow the discharge of any untreated or partially-treated brine, or residuals from brine treatment facilities, into surface waters. The Departments agree, but note that MDE has taken appropriate steps to prevent such discharge. To understand this situation, it is necessary to explain the regulation of direct and indirect discharges of pollutants.

Direct and indirect discharges of pollutants to navigable waters are regulated under the Clean Water Act through the National Pollutant Discharge Elimination System (NPDES) permit program. Authority for issuing permits in Maryland has been delegated to MDE. Currently, federal regulations mandate that “there shall be no discharge of waste water pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (*i.e.*, produced water, drilling muds, drill cuttings, and produced sand).” 40 CFR 435.32. Thus, the direct discharge of flowback or other brine is already prohibited.

Indirect discharge means 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.²⁶ There are, however, no national standards specifically for the indirect discharge of gas exploration and development wastewaters. As a result, some shale gas wastewater has been transported to POTWs that are not equipped to treat this wastewater. Where POTWs discharged the inadequately treated wastewater to fresh water streams, the salts in the brine entered the streams, where they could kill or damage the aquatic organisms. Where discharges of treated brine were upstream of drinking water intakes, they impacted drinking water by contributing to high levels of disinfection by-products.

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.

²⁶ These and other pretreatment general prohibitions that are designed to protect the POTW from damage and its workers from harm can be found at 40 CFR 403.5.

With regard to disposal in Class II injection wells, the UMCES-AL Report noted that establishing UIC Class II injection wells in Maryland would avoid long distance trucking of produced waters; however, it also noted that locations in Maryland suitable for siting injection wells may be very limited. The Departments agree that it is not likely that Class II wells will be located in Maryland and therefore defers any consideration of the matter unless and until someone proposes to apply for a permit for a Class II injection well.

In order to assure that all wastes and wastewater are properly treated or disposed of, the Departments propose to 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. The records may take the form of a log, invoice, manifest, bill of lading or other shipping documents. For shipments off-site, the record would have to include the following information:

1. The type of waste
2. The volume or weight of waste
3. The identity of the hauler
4. The name and address of the facility to which the waste was sent
5. The date of the shipment
6. 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. The requirements would be included as a condition of the permit.

L. Leak Detection

UMCES-AL Report recommendation 2-A

The Departments accept the proposed recommendations (summarized below) and include additional comments.

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.

A statement must be submitted listing all equipment available for the detection, prevention, and containment of gas leaks and oil spills. COMAR 26.19.01.06C(17).

MDE may not issue a drilling and operating permit if drilling or operations would result in physical and preventable loss of oil and gas. COMAR 26.19.01.09J.

On site air pollution monitoring, discussed in the monitoring section, shall be included as an element of the leak detection program.

M. Light

UMCES-AL Report recommendations 5-E, 5-E.1, 8-G, 8-H

The UMCES-AL Report recommends that night lighting be used only when necessary, directed downward, and use low pressure sodium light sources 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. The Departments accept the proposed recommendations for lighting at drill pad sites with the following modifications.

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.

The Departments agree that restrictions on hours of operation could reduce light pollution, but recognize that many activities are carried on continuously once they begin. Downward directed low pressure sodium light sources and screens might be required for such operations.

N. Noise

UMCES-AL Report recommendation 5-D, 9-B, 9-D, 9-D.3, 9-D.4, 9-D.5

The UMCES-AL Report recommends that each of the counties in western Maryland should revisit noise regulations and enforcement policies and confirm they are appropriate for this industrial activity. Additionally, the report recommends that noise be reduced by: requiring electric motors (in place of diesel-powered equipment) for any operations within 3,000 ft. of any occupied building; encouraging the use of electric motors in place of diesel-powered equipment for operations not within 3,000 ft. of an occupied building; restricting hours and times of operation to avoid or minimize conflicts; require a measurement of ambient noise levels prior to operation; the construction of artificial sound barriers where natural noise attenuation would be inadequate; and requiring all motors and engines to be equipped with appropriate mufflers.

The Departments agree that noise must be controlled, and that compliance with the existing noise regulations should be sufficient. The Departments recommend that the applicant for a permit submit a plan for complying with the noise standards and for verifying compliance after operations begin. The Departments will incorporate the concept of “noise sensitive locations” into its review of the CGDP. Site-specific noise provisions can be incorporated into individual permits.

Pursuant to State law, MDE has adopted environmental noise standards. A local government may adopt its own noise control ordinance, rules or regulations, provided they are not less stringent than those the State adopts. Enforcement of the environmental noise standards, whether State or local, is the responsibility of the local government. Noise limits apply at the boundary of: (1) a property; or (2) a land use category, as determined by the responsible political subdivision. Md. Env. Code, Title 3. The measurement of noise levels shall be conducted at points on or within the property line of the receiving property or the boundary of a zoning district²⁷, and may be conducted at any

²⁷ “Zoning district” means a general land use category, defined according to local subdivision, the activities and uses for which are generally uniform throughout the subdivision. For the purposes of this regulation, property which is not zoned “industrial”, “commercial”, or “residential” shall be classified according to use as follows: (a) “Industrial” means property used for manufacturing

point for the determination of identity in multiple source situations. COMAR 26.02.03.02D(2). The general standards for Environmental Noise are:

Table VI-1
Maximum Allowable Noise Levels (dBA)
for Receiving Land Use Categories

Day/Night ²⁸	Industrial	Commercial	Residential
Day	75	67	65
Night	75	62	55

Special rules apply to construction and demolition sites: a person may not cause or permit noise levels emanating from construction or demolition site activities which exceed: (a) 90 dBA during daytime hours; (b) The levels specified in the table above during nighttime hours. COMAR 26.02.03.02B. 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.” *Id.*

Methods for minimizing noise impacts resulting from drilling and fracturing operations include: (1) careful siting of facilities—distance, direction, timing, and topography are the primary considerations in mitigating noise impacts; (2) placement of walls, artificial sound barriers, or evergreen buffers between sources and receptors (*e.g.*, around well pads and compressor stations); (3) use of noise reducing equipment (*e.g.*, mufflers) on flares, drill rig engines, compressor motors, and other equipment; and (4) use of electric motors in place of diesel-powered equipment. In the event noise sensitive locations or sensitive species are identified in the Environmental Assessment, these additional measures may be necessary to protect against adverse impacts.

Currently, county government bears the responsibility for monitoring and enforcing noise regulations. However, many counties do not have the capacity or the equipment to monitor. For this reason, the Departments may require the permittee to hire an independent contractor to conduct periodic noise monitoring and additional noise monitoring in response to a complaint.

O. Invasive species

UMCES-AL Report recommendations 5-G, 5-G.1, 5-H, 6-H, 6-H.1, 6-H.2, 6-I

and storing goods; (b) “Commercial” means property used for buying and selling goods and services; (c) “Residential” means property used for dwellings. COMAR 26.02.03.01

²⁸ “Daytime hours” means 7 a.m. to 10 p.m., local time. “Nighttime hours” means 10 p.m. to 7 a.m., local time. COMAR 26.02.03.01

The UMCES-AL recommended that the permittee submit an invasive species plan that emphasizes early detection and rapid response and meets certain criteria. The Departments agree.

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:

1. flora and fauna inventory surveys of sites prior to operations, including water withdrawal sites;
2. 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;
3. interim reclamation following construction and drilling to reduce opportunities for invasion;
4. annual monitoring and treatment of new invasive species populations as long as the well is active; and
5. post-activity restoration to pre-treatment community structure and composition using seed that is certified free of noxious weeds.

P. Spill Prevention, Control and Countermeasures and Emergency Response

UMCES-AL Report recommendations 4-H, 5-B.1, 5-B.2, 7-B, 7-B.1, 7-B.2, 7-B.3

The UMCES-AL Report recommends that permit applicants should be required to develop site-specific emergency response plans, taking into account that the optimum response may differ depending on the season of the year and the topography of the site. Further, the report recommends that the plan must also include a list of all chemicals or additives used, expected wastes generated by hydraulic fracturing, approximate quantities of each material, the method of storage on-site, Material Safety Data Sheets for each substance, toxicological data, and waste chemical properties. The Departments agree that each permittee must prepare a site-specific emergency response plan and that the permittee must provide a list of chemicals and corresponding Safety Data Sheets to first responders before beginning operations; however, the Departments do not agree that all the detailed information described above needs to be in the plan or submitted to MDE with the permit application.

Spill Prevention, Control and Countermeasures Plans (SPCC Plans) are intended to prevent any discharge of oil. 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.

The federal Hazard Communication Program regulations, sometimes called Worker Right to Know, require that the chemical manufacturer, distributor or importer provide SDS for each hazardous chemical to downstream users as a way of communicating information on the hazards. Employers must ensure that SDSs are readily accessible to employees for all hazardous chemicals in their workplace.

Under revised regulations, the SDS must be presented in a consistent 16 section format. Sections 1 through 8 contain general information about the identity of the chemical, hazards, composition and ingredients, first aid measures, fire-fighting measures, response to releases, handling and storage, and measures to minimize worker exposure. Sections 9 through 11 contain other technical and scientific information, such as physical and chemical properties, stability and reactivity information and toxicological information. Sections 12 through 15 contain ecological information, disposal considerations, transport information, and regulatory information. Section 16 must include the date the SDS was prepared or last revised and it may contain other useful information. Where the preparer is unable to find any applicable information, it must be stated on the SDS.

The Departments believe that the SDSs and the other requirements for emergency response are sufficient to enable first responders and well pad staff to appropriately respond to emergencies involving chemicals. In Section VI-D, we require operators to provide a list of chemicals on site and SDSs to the local emergency response agency. 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.

Q. Site Security

UMCES-AL Report recommendations 7-C, 7-C.1, 7-C.2, 7-C.3, 10-F

The UMCES-AL Report recommends perimeter fencing, giving local emergency responders duplicate keys to locks, posting appropriate signage, and using security guards to control access. The Departments accept the proposed site security recommendations as best practices; however the decision whether to use security guards should be made by the permittee on a site-specific basis.

R. Closure and Reclamation both Interim and Final

UMCES-AL Report recommendation 1-K, 5-H, 10-E

The goal of reclamation is to return the developed area to native vegetation (or pre-disturbance vegetation in the case of agricultural land returning to production) and restore the original hydrologic conditions to the maximum extent possible. The UMCES-AL

Report recommended two-stage reclamation: (1) interim reclamation following construction and drilling to stabilize the ground and reduce opportunities for invasive species and (2) post-activity restoration using species native to the geographic range and seed that is certified free of noxious weeds.

The Departments agree.

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.

As recommended by UMCES-AL, topsoil should be stockpiled during site development activities, covered during storage, redistributed back onto agricultural land as part of the land reclamation process. Soil compaction should be avoided at all times.

SECTION VII – MONITORING, RECORDKEEPING AND REPORTING

UMCES-AL Report recommendations 1-A, 1-B, 2-A, 2-C, 2-D, 2-E, 3-G, 4-C, 5.G-1, 7-A.3

The Departments accept the proposed monitoring, recordkeeping and reporting recommendations with the following modifications, additions and comments.

- A. DNR emphasizes that a minimum of 2 years of pre-development baseline data is necessary to evaluate the condition and characteristics of aquatic resources, particularly the living resources, since statewide monitoring experience demonstrates there is great variability on a seasonal and annual basis.

Characterization and baseline monitoring data will be important to identify whether any impacts to the resources have occurred as a result of drilling activities, and can be used as basis for mitigating damage.

- B. 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.
- C. 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.
- D. 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.
- E. 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.
- F. Personnel and time needed for inspections and compliance activities cannot be determined until we have final regulations and have a sense of the pace and scope of drilling. Nevertheless, the Department can assess fees adequate to cover the expenses of the program, including inspections.

The Environment Article of the Maryland Code provides in pertinent part:

§ 14-105. Drilling well and disposing of well's products -- Application for permit

b) Fees. -- The Department shall establish and collect fees for:

- (1) The issuance of a permit to drill a well under § 14-104 of this subtitle;
 - (2) The renewal of a permit to drill a well under § 14-104 of this subtitle;
- and

(3) The production of oil and gas wells installed after October 1, 2010.

(c) Fees -- Rate. -- The fees imposed under subsection (b) of this section shall be set by the Department at the rate necessary to implement the purposes set forth in § 14-123 of this subtitle.

§ 14-123. Use of money

The Department shall use money in the Fund solely to administer and implement programs to oversee the drilling, development, production, and storage of oil and gas wells, and other requirements related to the drilling of oil and gas wells, including all 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.

MDE will consider all of the costs to be incurred by the State in connection with its gas well program and propose an appropriate fee schedule by regulation.

SECTION VIII – MISCELLANEOUS RECOMMENDATIONS

A. Zoning

UMCES-AL Report recommendation 1-M

The UMCES-AL Report recommended that both counties amend their zoning ordinances to spell out in which zoning districts MSGD would be permitted. Zoning is an excellent way to separate incompatible land uses; however, authority to enact zoning rests with the local jurisdictions. Zoning has been controversial, especially in Garrett County. It is a local matter over which the Departments have no control.

B. Financial assurance

UMCES-AL Report recommendations 1-N, 3-H

This recommendation has been satisfied with the 2013 legislative passage of SB854, sponsored by Senator George Edwards, providing financial assurance for gas and oil drilling.

C. Forced Pooling

UMCES-AL Report recommendation 1-D

The Departments offer the following comments regarding the forced pooling recommendation.

Consideration of this recommendation is premature. Once the requirements of the Executive Order have been fulfilled, this recommendation could receive additional consideration which would require further study, legal analysis and considerable governmental and public review.

SECTION IX – MODIFICATIONS TO PERMITTING PROCEDURES

The Departments are persuaded that the recommended best practices for permit procedures can be implemented through regulatory changes and policy without additional statutory authority. If natural gas extraction by high volume hydraulic fracturing is allowed in Maryland, more detailed procedures for the processing of the Comprehensive Gas Development Plan (CGDP) will have to be developed. The time schedule for processing the CGDP set forth in Section III will be followed.

SECTION X – IMPLEMENTING THE RECOMMENDATIONS

The Maryland General Assembly has authorized the Maryland Department of the Environment to regulate oil and gas wells. With a few notable exceptions, the statutory language is general and MDE is authorized to promulgate rules and regulations and to place in permits conditions it deems reasonable and appropriate to assure that the operations are carried out in compliance with the law and provide for public safety and the protection of the State's natural resources. Md. Env. Code Ann., §§ 14-103 and 14-110. This model allows the Department to apply expertise, exercise judgment and adapt to change.

The Department's regulations on oil and gas wells have not been revised since 1993 and thus were written before recent advances in technology and without the benefit of more recent research. Our current regulations for oil and gas wells are not appropriate for high volume hydraulic fracturing. Even though MDE could implement many of the recommendations in individual permits, the inconsistencies between the existing regulations and the recommendations would certainly cause confusion and could prompt lawsuits or permit challenges if natural gas extraction by high volume hydraulic fracturing is allowed in Maryland in the future. The CGDP would be difficult to implement without additional regulations. For these reasons, the regulations should be revised to reflect the recommendations. This is a lengthy process, with opportunities for review by the legislature and public participation.

APPENDIX A – MEMBERS OF THE COMMISSION

Chair

David A. Vanko, Ph.D., *geologist and Dean of The Jess and Mildred Fisher College of Science and Mathematics at Towson University*

Commissioners

George C. Edwards, *State Senator, District 1*

Heather Mizeur, *State Delegate, District 20*

James M. Raley, *Garrett County Commissioner*

William R. Valentine, *Allegany County Commissioner*

Peggy Jamison, *Mayor of Oakland*

Shawn Bender, *division manager at the Beitzel Corporation and president of the Garrett County Farm Bureau*

Ann Bristow, Ph.D., *board member, Savage River Watershed Association**

Stephen M. Bunker, *director of Conservation Programs, Maryland Office of the Nature Conservancy*

Jeffrey Kupfer, Esq., *senior advisor, Chevron Government Affairs*

Clifford S. Mitchell, M.D., *director, Environmental Health Bureau, DHMH*

Dominick E. Murray, *secretary of the Maryland Department of Business and Economic Development*

Paul Roberts, *Garrett County resident and co-owner of Deep Creek Cellars winery*

Nicholas Weber, Ph.D., *chair of the Mid-Atlantic Council of Trout Unlimited*

Harry Weiss, Esq., *partner at Ballard Spahr LLP*

* Dr. Bristow was appointed to the Commission in late 2013 to replace John Fritts, Ph.D., who resigned.

APPENDIX B – COMMENTS OF THE ADVISORY COMMISSION

The purpose of the Marcellus Shale Safe Drilling Initiative is to assist State policymakers and regulators in determining whether and how gas production from the Marcellus Shale can be carried out in Maryland without the risk of unacceptably and negatively impacting public health, safety, the environment and natural resources. The Departments of Natural Resources and the Environment are to consult with the Advisory Commission during the Departments' investigations and production of the three reports called for in Executive Order 01.01.2011.11. The Advisory Commission plays a valuable role by representing diverse points of view, making suggestions to the Departments, and providing constructive criticism of the Departments' work and decisions. The Advisory Commission conducts its affairs openly and transparently and actively seeks and considers public comments, which are received through the Advisory Commission's web site and at Commission meetings.

Advisory Commission members include representatives from local and State government, the gas industry, environmental organizations, businesses, private citizens and landowners, a public health professional, a geology professor, and an environmental lawyer. The members have different perspectives and opinions, as well as a range of expertise and, consequently, achieving unanimity on all the issues discussed is difficult. From its inception, members of the Advisory Commission have agreed that if shale gas production is to proceed in Maryland, it needs to be done "right." Although the definition of "right" may vary to some extent among the Commissioners, all agree that safety is of paramount importance.

A key practice is the requirement of a Comprehensive Gas Development Plan (CGDP). Some Commissioners identified this as an excellent idea and the most important of the recommendations. Although most Commissioners supported the concept, several expressed serious concerns about it. These included:

- By favoring multi-well pads and avoiding sensitive areas, the CGDP will concentrate the adverse impact of gas development in a few places to the detriment of those who live there;
- The CGDP adds an onerous and cumbersome layer of review and approval without significant benefit; and
- There are practical problems to implementing a CGDP, including the time needed to implement to plan and the ability to complete an exploratory well and adjust the plan.

This Appendix summarizes the positions of the members of the Advisory Commission on the best practices in this report. It reflects the opinions of individual Commissioners as of June 13, 2014, regarding the suitability of the State's proposed best practices for use in

the ongoing risk assessment study. All Commissioners reserve the right to change their opinions as more information becomes available, and as ongoing studies are completed. Changes in Commissioner viewpoints will be reflected in the third report.

At the June 13, 2014, Marcellus Shale Advisory Commission meeting, Commissioners were asked to respond, for each proposed best practice, to this question:

Given my current understanding of the facts and the science, I think

1. it is an appropriate standard to carry forward to the risk assessment.
2. it may not be the appropriate standard to carry forward to the risk assessment, but I can live with it.
3. it is not an appropriate standard to carry forward to the risk assessment because [fill in the blank].

The statement was qualified by “given my current understanding of the facts and the science” in recognition that new information will continue to become available as more research is conducted and published.

For every best practice, the majority of Commissioners voting agreed either that the best practice was an appropriate standard to carry forward to the risk assessment or, even though they were not sure it was the appropriate standard, they were comfortable with allowing it to proceed to the risk assessment. When Commissioners did not think the practice was an appropriate standard, they had an opportunity to provide a reason. By way of example, these included:

- the standard is not a best practice because it has not been shown to be superior to the approach commonly employed;
- there is a lack of science supporting the practice;
- there is insufficient knowledge about the groundwater aquifers and flow systems in western Maryland;
- there is too little data on health effects, air quality and noise impacts;
- the setback is too long
- the setback is not long enough; and
- the practice is insufficiently described to make a judgment.

Additional detail is provided in portions of the minutes of the June 13 meeting. The votes are tallied in the following chart:

Section III. Comprehensive Gas Development Plan (CGDP) for landscape level planning	
Response	Commissioners
1	Bunker, Edwards, Jamison, Mitchell, Raley, Vanko, Weiss
2	Kupfer
3	<ul style="list-style-type: none"> • Bristow: Will provide written comment, approach not shown to be

	<p>superior to the approach commonly employed; there is no research on the effects of CGDP on public health and there is concern that this practice may intensify potential impacts.</p> <ul style="list-style-type: none"> • Roberts: Not appropriate, no science to support it; there is no research on the effects of CGDP on public health and there is concern that this practice may intensify potential impacts. • Weber: Endorse approach for protecting natural resources, the CGDP incompletely deals with human and safety concerns and how they will be addressed
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Section V. Individual well permit following CGDP approval	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Raley, Vanko, Weiss
2	
3	<ul style="list-style-type: none"> • Bristow: • Mitchell: Needs to have DHMH and other agencies as commenting agencies on permit review • Roberts: Same as Mitchell • Weber: Lack of specific API references, same as Mitchell
The Departments agreed to amend the practice to include notification of all landowners within a 2,500 ft radius.	

Section IV. Location restrictions and setbacks	
1,000 ft setback from well to property boundary	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Raley, Vanko, Weiss
2	Mitchell
3	<ul style="list-style-type: none"> • Bristow: Needs to be the Limit of Disturbance (LOD), not the borehole • Roberts: Lack of supporting science • Weber: Lack of supporting science, no accounting of groundwater flow upstream or downstream from the well

Section IV. Location restrictions and setbacks	
2,000 ft vertical setback between lowest freshwater zone and target formation	
Response	Commissioners
1	Edwards, Jamison, Raley, Weber
2	Bunker, Kupfer, Mitchell, Weiss, Vanko
3	<ul style="list-style-type: none"> • Bristow: Lack of supporting science and knowledge of aquifer • Roberts: Same as Bristow

Section IV. Location restrictions and setbacks	
450 ft setback from aquatic habitat to edge of pad	
Response	Commissioners
1	Bunker, Edwards, Jamison, Mitchell, Raley, Vanko
2	Kupfer, Weiss

3	<ul style="list-style-type: none"> • Bristow: Need implementation of Wolman report recommendations, groundwater contamination via casing failure could directly impact aquatic habitat, 450 ft not protective enough, concerned about agricultural land • Roberts: Same as Bristow
---	--

Section IV. Location restrictions and setbacks 600 ft setback from special conservation areas to edge of pad	
Response	Commissioners
1	Edwards, Jamison, Mitchell, Raley, Vanko
2	Bunker, Kupfer, Weber, Weiss
3	<ul style="list-style-type: none"> • Bristow: Need health data/studies on air quality impacts • Roberts: Same as Bristow, shocking the state would limit offset to 600 ft from an “Irreplaceable Natural Areas”

Section IV. Location restrictions and setbacks 300 ft setback from special conservation areas to edge of pad	
Response	Commissioners
1	Edwards, Jamison
2	Bunker, Kupfer, Raley, Vanko, Weiss
3	<ul style="list-style-type: none"> • Bristow: Need health data/studies on air quality and noise impacts • Mitchell: Would like to evaluate noise data • Roberts: Same as Bristow, not enough distance to reduce noise and air impacts • Weber: Same as Roberts

Section IV. Location restrictions and setbacks 750 ft setback from downdip side of limestone outcrops to borehole	
Response	Commissioners
1	Bunker, Edwards, Jamison, Mitchell, Raley, Weiss, Vanko
2	Kupfer, Weber
3	<ul style="list-style-type: none"> • Bristow: Don’t see the reason to reduce the setback, not enough information • Roberts: Not enough distance, not properly evaluated

Section IV. Location restrictions and setbacks Eliminate absolute 1,000 ft setback from coal mines in lieu of pilot hole and geologic investigations to develop site specific drilling, casing and cementing techniques	
Response	Commissioners
1	Bunker, Jamison, Kupfer, Mitchell, Raley, Weiss, Vanko
2	Bristow, Edwards, Roberts, Weber
3	

Section IV. Location restrictions and setbacks 1,320 ft setback from historic gas wells to borehole, including laterals	
Response	Commissioners
1	Edwards, Jamison, Mitchell, Raley, Weiss, Vanko
2	Bunker, Kupfer
3	<ul style="list-style-type: none"> • Bristow: Not enough data • Roberts: Not enough data • Weber: Not enough data

Section IV. Location restrictions and setbacks 1,000 ft setback from compressor stations to any occupied building	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer
2	Mitchell, Raley, Weber, Weiss, Vanko
3	<ul style="list-style-type: none"> • Bristow: No health data/studies • Roberts: No health data/studies

Section IV. Location restrictions and setbacks 1,000 ft setback from edge of drill pad disturbance to any occupied building	
Response	Commissioners
1	Bunker, Vanko
2	Edwards, Jamison, Kupfer, Mitchell, Raley, Weiss
3	<ul style="list-style-type: none"> • Bristow: No data/studies on how animals and agricultural use are affected by direct impacts and byproducts • Roberts: Same as Bristow • Weber: Same as Bristow

Section IV. Location restrictions and setbacks 2,000 ft (or reduced with study and consent to minimum of 1,000 ft) setback from a private drinking water well to the well pad	
Response	Commissioners
1	Bunker, Edwards, Jamison, Raley, Vanko, Weiss
2	Mitchell
3	<ul style="list-style-type: none"> • Bristow: Recommend 1 kilometer setback, no science to support a lesser setback, use the Vengosh study results • Kupfer: Setback is too wide and is unsubstantiated by existing information. Private wells have not been mapped out with setbacks applied in the constraint analysis. • Roberts: Same as Bristow • Weber: Same as Bristow

Note: The risk analysis will run scenarios on 3 setback distances of 1,000 ft, 2,000 ft and 1 kilometer.

Section IV. Location restrictions and setbacks 1,000 ft setback from a wellhead protection area or a source water assessment area for a public ground water system to the well pad	
Response	Commissioners
1	Bunker, Jamison, Mitchell, Raley, Vanko, Weber
2	Bristow, Edwards, Kupfer, Roberts, Weiss
3	

Section IV. Location restrictions and setbacks 1,000 ft setback from a source water assessment area for a public surface water intake system	
Response	Commissioners
1	Mitchell, Raley, Vanko
2	Bristow, Bunker, Edwards, Jamison, Kupfer, Roberts, Weber, Weiss
3	

Section IV. Location restrictions and setbacks A well pad cannot be located within the watersheds of the following public drinking water reservoirs: Broadford Lake, Piney Reservoir, Savage Reservoir	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Vanko, Weber, Weiss
2	
3	

Section VI. Engineering, Design and Environmental Controls and Standards A. Site construction and sediment and erosion control plans	
Response	Commissioners
1	Bunker, Edwards, Jamison, Weiss, Vanko
2	Bristow, Kupfer, Mitchell, Roberts
3	Weber: Insufficient information on best practices – wants more detail
Note: No vote recorded for Raley	

Section VI. Engineering, Design and Environmental Controls and Standards B. Transportation planning	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Raley, Vanko
2	Bristow, Mitchell, Weber, Weiss
3	Roberts

Section VI. Engineering, Design and Environmental Controls and Standards C. Water	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Vanko, Weiss
2	Bristow, Roberts, Weber

3	
---	--

Section VI. Engineering, Design and Environmental Controls and Standards	
D. Chemical disclosure	
Response	Commissioners
1	
2	Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Vanko, Weiss
3	<ul style="list-style-type: none"> • Bristow: Grossly inappropriate • Roberts: Extremely complicated issue, not enough time to research the issue, don't fully understand the details • Weber: Same as Roberts, concerned about depleted uranium used in perforation devices

Section VI. Engineering, Design and Environmental Controls and Standards	
E. Drilling	
Response	Commissioners
1	Edwards, Raley, Bunker, Jamison, Mitchell, Vanko
2	Bristow, Kupfer, Roberts, Weber
3	
Note: No vote recorded from Weiss	

Section VI. Engineering, Design and Environmental Controls and Standards	
F. Casing and cement	
Response	Commissioners
1	Edwards, Jamison, Weiss
2	Bunker, Kupfer, Mitchell, Raley, Vanko
3	<ul style="list-style-type: none"> • Weber: Lack of science and understanding • Roberts: Same as Weber • Bristow: Same as Weber, would like to see a cost assessment of enforcement needs by MDE

Section VI. Engineering, Design and Environmental Controls and Standards	
G. Blowout prevention	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weber, Weiss, Vanko
2	
3	

Section VI. Engineering, Design and Environmental Controls and Standards	
H. Hydraulic fracturing	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weiss, Vanko
2	Weber

3	
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Section VI. Engineering, Design and Environmental Controls and Standards	
I. Flowback and produced water	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weber, Weiss, Vanko
2	
3	

Section VI. Engineering, Design and Environmental Controls and Standards	
J. Air emissions	
Response	Commissioners
1	Bunker, Edwards, Kupfer, Mitchell, Raley, Vanko
2	Jamison, Weiss
3	<ul style="list-style-type: none"> • Roberts: This is an area of evolving research, can't support at this time • Weber: Same as Roberts • Bristow: Same as Roberts

Section VI. Engineering, Design and Environmental Controls and Standards	
K. Waste and wastewater treatment and disposal	
Response	Commissioners
1	Edwards, Kupfer, , Weiss Vanko
2	Bunker, Jamison, Mitchell, Raley
3	<ul style="list-style-type: none"> • Roberts: State should review and revise regulations on what constitutes on site storage (length of time, type of material, etc) so that this practice is not a de facto option for disposal and doesn't result in a prolonged period of time allowable for on site storage • Weber: Same as Roberts • Bristow: GPS tracking should be publicly available, recognize that shipping of waste exacerbates the problem of waste disposal, there are Environmental Justice concerns about exporting our wastes to another state

Section VI. Engineering, Design and Environmental Controls and Standards	
L. Leak detection	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weber, Weiss, Vanko
2	
3	

Section VI. Engineering, Design and Environmental Controls and Standards M. Light	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weber, Weiss, Vanko
2	
3	

Section VI. Engineering, Design and Environmental Controls and Standards N. Noise	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Weber, Weiss, Vanko
2	Bristow, Roberts
3	

Section VI. Engineering, Design and Environmental Controls and Standards O. Invasive species	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Weiss, Vanko
2	Bristow, Roberts, Weber
3	

Section VI. Engineering, Design and Environmental Controls and Standards P. Spill prevention, control and countermeasures and emergency response	
Response	Commissioners
1	Bunker, Edwards, Jamison, Kupfer, Mitchell, Roberts, Weiss, Vanko
2	Raley, Weber
3	Bristow: Need to address financial and capacity needs for emergency response

Section VI. Engineering, Design and Environmental Controls and Standards Q. Site security	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weber, Weiss, Vanko
2	
3	

Section VI. Engineering, Design and Environmental Controls and Standards R. Closure and reclamation	
Response	Commissioners
1	Bristow, Bunker, Edwards, Jamison, Kupfer, Mitchell, Raley, Roberts, Weber, Weiss, Vanko
2	
3	

Section VII. Monitoring, Recordkeeping and Reporting	
Response	Commissioners
1	Bunker, Edwards, Mitchell, Raley,
2	Jamison, Kupfer, Roberts, Vanko, Weiss
3	<ul style="list-style-type: none">• Weber: Needs more detail on the practices• Bristow: Same as Weber, monitoring information should be made publicly available

APPENDIX C – RESPONSE TO PUBLIC COMMENTS

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AIR EMISSIONS

1. The greenhouse gas benefits of natural gas are overstated.
 - a. I ask that the State also re-consider its statement in the Overview (Sec. II) that natural gas produces lower GHG emissions than coal when burned for electricity. Any comparisons of the two energy sources should analyze the complete “life-cycle” of production. Calculation of the GHG footprint of shale gas development should include documentation of leakage rates (rates of higher than 3 percent effectively cancel out gas’s GHG advantages over coal use) and a full accounting of potential emissions from all truck traffic needed for extraction and waste disposal. If Maryland requires a closed-loop system for waste disposal, and then transport of the waste to other states, it is likely that the truck transport needs here (and the resulting diesel emissions) will be greater than average.
 - b. A recent study published in the Proceedings of the National Academy of Sciences found that the methane leakage rate would have to be kept below 1 percent in order to ensure that natural gas has an immediate climate benefit over all other fossil fuels. [Alvarez, Ramon A., Stephen W. Pacala, James J. Winebrake, William L. Chameides, and Steven P. Hamburg. "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure." Proceedings of the National Academy of Sciences (2012): n. pag. Web.]

The statement in the draft report: “When burned to generate electricity, natural gas produces lower greenhouse gas emissions than oil and coal....” was intended to address only the burning of the fuel to generate electricity, and did not consider the life-cycle of the process. The Departments acknowledge that leakage of methane could reduce or even negate the advantage of burning natural gas, and MDE is proposing measures to reduce the emissions of methane to the maximum extent practicable.

2. Companies should be required to reduce, report, and offset methane emissions.
 - a. The study should include a section dedicated to best practices for reducing methane emissions at every stage of the natural gas system.
 - b. In order to achieve real “best practices” the state should require drilling permittees to meet the maximum emissions abatement potential based on technologies that exist today, to be achieved through a combination of offsets and EPA-certified prevention measures.
 - c. Permittees should be required to work with EPA STAR Program staff to estimate their annual greenhouse gas emissions after the adoption of cost-effective abatement control measures, and include that estimate in their permit application. In order to ensure that natural gas production and processing does not contribute to climate change, permittees should then include a plan for investing in carbon offsets to offset their estimated annual leakage.

- d. Fugitive emissions from oil and gas operations are a source of direct and indirect greenhouse gas emissions. The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC Guidelines) provide a three-tier approach for assessing fugitive emissions from oil and gas activities. These approaches range from the use of simple production-based emission factors and high level production statistics (*i.e.*, Tier-1) to the use of rigorous estimation techniques involving highly disaggregated activity and data sources (*i.e.*, Tier-3), and could include measurement and monitoring programs. There is no mention of use of Tier 3 monitoring program to ensure proper controls are in place.
- e. Gas companies should be required to meet a zero percent leakage rate for methane throughout the fracking process. To the extent leakage cannot be reduced to zero, the releases should be offset.
- f. The release of methane has been a great danger to people and animals, and methane is a potent greenhouse gas. The BMPs should require gas companies to meet a 1 or 2 percent leakage rate for methane throughout the drilling process. Leakage should be monitored by a certifiable method and reported annually.
- g. In order to account for methane leakage that will occur after shale gas enters the transmission line, MDE should consider requiring permittees to offset leakage at a ratio greater than 1:1.

The Department of the Environment intends to require top-down Best Available Technology (BAT) for the control of methane emissions. This 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. MDE will analyze top-down BAT demonstrations from applicants and approve the applicants BAT determination before a permit is issued. This builds on the EPA STAR program, and therefore a separate requirement to participate in this voluntary EPA program is not needed. MDE will also require a rigorous leak detection and repair program.

MDE is considering whether it is feasible to require permittees to estimate the remaining methane emissions and offset them with greenhouse gas credits. If this occurs, the permittees will have to estimate and report emissions to the State annually. Under EPA's Greenhouse Gas Reporting Program, an onshore natural gas production²⁹ facility that emits 25,000 metric tons of carbon dioxide equivalents (CO₂e) or more per year must report its greenhouse gas emissions annually to EPA.

²⁹ Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery operations using CO₂ or natural gas injection, and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. 40 CFR § 98.230.

Requiring production facilities to offset methane emissions at greater than a 1:1 ratio to account for methane leakage that occurs after the gas enters the transmission line would add to the cost of natural gas without reducing leakage in downstream infrastructure, such as transmission lines, because these are separately owned and operated.

3. Venting and flaring

- a. Venting should be absolutely prohibited.
- b. The proposed BMPs allow flaring for up to 30 days for exploratory wells and place some limits on flaring during drilling. This BMP is too vague and all flaring should be prohibited. Flaring for periods longer than several days under any circumstances will result in an unacceptable level of noise and light and possibly dangerous air quality for nearby residents, especially those with small children or respiratory conditions.
- c. The report says that flares should have no visible emissions. How can flared emissions NOT be visible?

Vented emissions are releases to the atmosphere by design or operational practice. Use of BAT for emissions control will reduce the venting of emissions, as will the requirement for Reduced Emissions Completion. Flares are a critical piece of safety equipment at natural gas sites to ensure that combustible gases do not accumulate and cause an unsafe condition. The goal is to use the flare as little as possible, but a flare or other combustion device should be available in case of an upset.

The light of a flare would make it visible, but the concept of “no visible emissions” refers to the opacity or “smokiness” of the exhaust from a flame, not light. If a flare is operating properly, there should be little or no unburned fuel to appear as smoke and the combustion products will be mostly carbon dioxide and water.

4. Diesel Generators / Electricity from the Grid

- a. Where possible, electricity from electrical transmission lines should be used to minimize air and noise pollution; natural gas and or solar should be used for all on-site electrical generation where feasible.
- b. Maryland should prohibit diesel generators, and take a stronger stance on prohibiting internal combustion engines for compressors and the like.

As stated in the draft report, there are multiple factors which would favor the use of one power source or fuel over another, including the land disturbance necessary to bring power to the site, the greenhouse gas footprint of electricity supplies and the loss of power resulting from running electrical transmission lines to the drill site. The Departments therefore proposed to require applicants to provide a power plan that results in the lowest practicable impact from the choice of energy source.

EPA has promulgated air quality regulations for stationary engines which differ according to whether: 1) the engine is new or existed before the regulations took effect; 2) the engine is located at an area source or a major source; and 3) the engine is a compression ignition or a spark ignition engine. These regulations include National Emission Standards for Hazardous Air Pollutants (NESHAP)40 CFR Part

63, Subpart ZZZZ (“the RICE rule”), New Source Performance Standards (NSPS) for Stationary Spark Ignition Internal Combustion Engines 40 CFR Part 60, Subpart JJJJ and NSPS 40 CFR Part 60, Subpart IIII.

Under EPA regulations, however, stationary source rules do not apply to motor vehicles, or to non-road engines, which are: 1) self-propelled (tractors, bulldozers); 2) propelled while performing their function (lawnmowers); or 3) portable or transportable (has wheels, skids, carrying handles, dolly, trailer or platform). Note: a portable non-road engine becomes stationary if it stays in one location for more than 12 months (or full annual operating period of a seasonal source).

The Department of the Environment is investigating the feasibility (legal and technical) of regulating non-road engines at Marcellus Shale drilling sites.

5. Health Issues

- a. Evaporation and crystallization when combined with other chemicals which may be used/mixed on-site at gas-wells cause ground-level ozone which have serious health consequences on people, animals and plants.
- b. Compression stations create toxic air that has been linked to illness.
- c. Unsafe levels of specific emissions and radiation should be prohibited.
- d. A study done by The Colorado School of Health found air pollution caused by hydraulic fracturing may contribute to “acute and chronic health problems for those living near natural gas drilling sites.”
(http://attheforefront.ucdenver.edu/?p=2546&utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+theforefront+%28%40theforefront%29).
- e. The state should consider that toxic air pollutants also pose a threat in determining setbacks. One peer-reviewed study found high levels of endocrine-disrupting chemicals in the air during the drilling phase. From the study: “Selected polycyclic aromatic hydrocarbons (PAHs) were at concentrations greater than those at which prenatally exposed children in urban studies had lower developmental and IQ scores.”
<http://www.endocrinedisruption.com/chemicals.air.php>

Ground level or "bad" ozone is not emitted directly into the air, but is created by chemical reactions between oxides of nitrogen (NOx) and volatile organic compounds (VOC) in the presence of sunlight. Emissions from industrial facilities and electric utilities, motor vehicle exhaust, gasoline vapors, and chemical solvents are some of the major sources of NOx and VOC, and are precursors to ground level ozone. The State is proposing to require that best available technology be used to control emissions from well pad operations.

To the extent Maryland is not preempted by regulations of the Federal Energy Regulatory Commission, Maryland will enforce a minimum setback distance of 1,000 feet between a compressor station and an occupied building. Data from recent air monitoring studies of well controlled Marcellus operations using the most sensitive

monitoring techniques show concentrations well below health effects levels at 1000 feet.

MDE is considering requiring applicants – in certain situations where drilling is close to communities -- to demonstrate compliance with State air toxics regulations - COMAR 26.11.15. The basic requirements for demonstrating air toxics compliance is to estimate emissions; use State-provided screening models or other modeling to estimate concentrations off of the property; and show that offsite concentrations of toxic air pollutants are below health protective benchmarks established in the regulations.

6. Reduced Emissions Completions/Green Completions

- a. The Draft is lacking in the required use of ‘Reduced Emissions Completions’ industry practice.
- b. The proposed Maryland BMP provision for green completions at wellhead is an important and achievable provision that will greatly contribute to reducing GHG footprint of gas production activities in the state. Requiring green completions will provide important near-term reductions in GHG associated with gas development in Maryland.
- c. State regulations should require green completions for fracking, refracking and workovers, and also incorporate reporting requirements for green completions, gas bleed limits for pneumatic controllers, reduction requirements from storage vessels at the well site, and air toxic requirements from glycol dehydrators used at the well site.

The draft best practices report mandated the use of Reduced Emissions Completions for all wells but did not explicitly say that it should also be required for re-fracturing. It will be. A workover is the process of performing major maintenance or remedial treatments on a gas well. BAT emissions control technology will be mandatory.

7. Detecting and Repairing Leaks and Fugitive Emissions

- a. Gas companies should be required to implement the model leakage detection and repair (LDAR) program rules as described in EPA’s “Leak Detection and Repair: A Best Practices Guide.” In order to avoid the preventable loss of gas during the transmission and storage and distribution phases, the methane LDAR recommendations should be expanded to include transmission and distribution pipelines, pipeline compressor stations, and storage facilities.
- b. The BMPs recommend that a methane leak detection and repair (LDAR) program must be established from wellhead to transmission line. This is a strong recommendation and it is vital that it is implemented strongly. Maryland’s leak detection and repair BMP should be strengthened by requiring that the programs conform to EPA’s Natural Gas STAR Program guidelines and EPA’s best practice guidelines for leakage detection and repair programs, the elements of which include:

- i. Written LDAR Program

- ii. Training
- iii. LDAR Audits
- iv. Contractor Accountability
 - v. Internal Leak Definition for Valves and Pumps
 - vi. More Frequent Monitoring
 - vii. Repairing Leaking Components
- viii. Delay of Repair Compliance Assurance
 - ix. Electronic Monitoring and Storage of LDAR Data
 - x. QA/QC of LDAR Data
 - xi. Calibration/Calibration Drift Assessment
 - xii. Records Maintenance
- c. We urge an approach that leads to a leak prevention planning requirement and a process of continuous improvement.

The Departments agree that a strong LDAR program is essential and will require each permittee to develop and implement a plan to detect and repair leaks from the wellhead to the transmission line that meets EPA's guidelines. MDE's authority, however, does not extend to the transmission lines. MDE will provide detailed guidance for the LDAR program, including guidance on detection methods, frequency of inspections, repair and recordkeeping. A gas well permit is renewed every five years during the life of the well, and this provides an opportunity for improving the guidance and requiring a revised LDAR plan.

8. Recommended Emission Controls

- a. The minimum state standards should require that permittees adopt these ten technologies and practices.
 - i. Green Completions to capture oil and gas well emissions.
 - ii. Plunger Lift Systems or other well deliquification methods to mitigate gas well emissions.
 - iii. Tri-Ethylene Glycol (TEG) Dehydrator Emission Controls to capture emissions from dehydrators.
 - iv. Desiccant Dehydrators to capture emissions from dehydrators (when the gas flow rate is less than 5 MMcfd and have temperature and pressure limitations).
 - v. Dry Seal Systems to reduce emissions from centrifugal compressor seals.
 - vi. Improved Compressor Maintenance to reduce emissions from reciprocating compressors.

- vii. Low-Bleed or No-Bleed Pneumatic Controllers used to reduce emissions from control devices.
 - viii. Pipeline Maintenance and Repair to reduce emissions from pipelines.
 - ix. Vapor Recovery Units used to reduce emissions from storage tanks.
 - x. Leak Monitoring and Repair to control fugitive emissions from valves, flanges, seals, connections and other equipment.
- b. We urge that all of the EPA New Source Performance standards be included and most importantly they be made mandatory.

Requiring top-down BAT emissions control technology will require that the operator 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, making it unnecessary to list the specifically requested technologies and practices.

Applicable EPA New Source Performance Standards are mandatory requirements.

9. The March 2013 CSSD standards appear to be particularly stringent in the area of air pollution. For instance, their performance standard #10 quantifies “green completion” by calling for a methane “destruction efficiency” of 98 percent. Their performance standard #11 specifies what percentage of drill rig engines should comply with EPA Tier 4 emission standards by what year.

The Maryland best practices recommendations are consistent with CSSD performance standard #10. Maryland is probably preempted from making performance standard #11 a requirement because section 209 of the Clean Air Act precludes it. CSSD and its members are, of course, free to voluntarily accelerate compliance dates.

ANCILLARY INFRASTRUCTURE

1. Gathering lines
- a. Standards for the location, materials, construction or testing of gathering lines must be addressed before permitting is approved in the State of Maryland.
 - b. The absence of specific BPs for gathering lines, gas processing units, compressor stations, or aquifer hydrological considerations are unacceptable.
 - c. The Maryland Public Service Commission should adopt standards for the location, materials, construction or testing of these lines before MDE approves CGDP plans or issues permits
 - d. Significantly stronger and more hazardous volatile components in unconventional production, compared to standard output in past decades accelerate pipeline corrosion as well.

- e. The report notes that the Maryland Public Service Commission (PSC) regulates intrastate gas and liquid pipelines, and that it appears that the PSC has not established any standards for the location, materials, construction, or testing of gathering lines. API has a published recommended practice, RP 80, “Guidelines for the Definition of Onshore Gas Gathering Lines” that the PSC and others may find of value.

The federal Pipeline and Hazardous Materials Safety Administration (PHMSA), regulates interstate gathering lines and the PSC regulates intrastate gathering lines for pipeline safety. PHMSA has set standards for the design, installation, construction, and initial testing and inspection of gathering lines that apply to intrastate gathering lines as well as interstate gathering lines. If the lines are metallic, corrosion protection is required. The location of intrastate gathering lines is not under the control of either PHMSA or the PSC. The locations of gathering lines will be addressed in the CGDP.

The PHMSA is in the process of collecting new information about gathering pipelines in an effort to better understand the risks they may now pose to people and the environment. If the data indicate a need, PHMSA may establish new safety requirements for large-diameter, high-pressure gas gathering lines in rural locations. Pending this action, the Departments are recommending two simple and commonsense requirements: that the locations of the lines be registered through Miss Utility, and that all pipelines and fittings 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.

The determination of whether a pipeline is a gathering line can be complicated, and both API RP 80 and the PHMSA webpage have helpful information.

2. Compressor station planning is omitted and should be inserted with “pipeline planning” in the planning principles.

Page 10 of the draft BP report includes the planning principle “adhere to Departmental siting policies (to be developed) to guide pipeline planning and direct where hydraulic directional drilling and additional specific best management practices are necessary for protecting sensitive aquatic resources when streams must be crossed.” This principle applies to linear facilities, like pipelines. Compressor stations are covered under the CGDP. On page 9 of the draft BP report in the Application Criteria and Scope section it states: “Companies intending to develop natural gas resources are required to submit a CGDP for the area where the applicant may conduct gas exploration or production activities and install supporting infrastructure (compressor stations, waste water treatment facilities, roads, pipelines, etc.) for a period of at least five years.”

3. UMCES-AL recommends that applicants wishing to drill wells be required to notify property owners residing within the established setback that an application has been filed for development. This notification requirement should also apply to siting of compressor stations and other ancillary equipment. (As outlined in Title 20 of the Md. Code, Public Service Commission Article) [The commenter presumably means COMAR Title 20] Applicants who wish to construct ancillary

infrastructure are required to notify all landowners whose property line falls within the current required setback (1,000 feet.)

The Departments have been unable to locate a recommendation by UMCES-AL to notify property owners “residing within the established setback area.” The Departments adopted UMCES-AL recommendation 4-B, that the applicant be required to notify the owners of any drinking water well within 2,500 feet of the vertical borehole that an application has been filed. Current regulations require the applicant for a well permit to certify that the applicant has notified, in writing, each landowner and leaseholder of real property that borders the proposed drillable lease area of the applicant's intention to file an application for a permit to drill a well. The Departments would retain this requirement and add the notification of owners of drinking water wells within 2,500 feet.

The locations of ancillary facilities, including compressors, will be reviewed in the CGDP. The Departments will consider requiring that applicants for approval of a CGDP also notify each landowner and leaseholder of real property that borders the proposed drillable lease area and any other location where ancillary infrastructure will be located. There will be opportunities for public participation in the CGDP review process.

4. Should include the statement, “Any further plans to modify the engineering or capacity to exceed the designed limits will not be allowed without a plan for a complete upgrade of the pipeline to newer expected maximum pressures.”

Pipelines should not be operated above design limits. If new regulations for pipelines are adopted, the regulations generally specify whether they apply to existing pipelines.

5. Comment: This statement from the draft report is incorrect: “In the past, gathering lines were generally small diameter and did not operate under high pressure. PHMSA has recognized that lines being put into service in shale plays like the Marcellus are generally of much larger diameter and operating at higher pressure than traditional rural gas gathering lines, increasing the concern for safety of the environment and people near operations.” The rural gathering lines from the Accident Dome underground storage wells are under very high pressure when gas is being injected into the wells during warm months and extracted during the winter months.

The statement was adapted from this sentence in a PHMSA FAQ on gathering lines: “The lines being put into service in the various shale plays like Marcellus, Utica, Barnett and Bakken are generally of much larger diameter and operating at higher pressure than traditional rural gas gathering lines, increasing the concern for safety of the environment and people near operations.” It is not clear whether the pipelines connected to the Accident Dome underground storage wells would be classified as gathering lines or transmission lines. In any event, the statement is qualified by the word “generally.”

6. There is a need to ensure proper regulation of rural compressor stations that may not be regulated by the federal government.

Rural compressor stations that are part of interstate pipelines are regulated by PHMSA and FERC. The locations of compressor stations on gathering lines and intrastate pipelines will be addressed in the CGDP. Compressors, if large enough, also require air permits from MDE.

CHEMICALS

1. The State should prohibit the injection of any toxic chemical into the earth.

Almost all substances, including water and minerals essential to human health, are toxic at some dose. The best practices recommendation was that the applicant would disclose the identity of each chemical to be used in drilling and fracturing, including trade secret chemicals, to MDE. Only approved chemicals could be used. The best practices will be revised to provide that the maximum amount of a chemical expected to be used, as well as the identity of the chemical, must be provided to MDE with the permit application.

Wastewater can be disposed of in deep injection wells. Class II wells inject fluids associated with oil and natural gas production. There are no Class II wells in Maryland, and it is unlikely that any could be established because the geology is not suitable. If deep well injection is found to be feasible in Maryland in the future, the public will have opportunity to participate in the permitting process. EPA has established regulations for Class II wells that are designed to protect drinking water.

2. Information about toxicological profiles and epidemiological evaluations, exposure risks, protective equipment and protective measures for every chemical used should be provided to MDE, DHMH, workers on site, persons living adjacent to the site, health professionals, and emergency responders.

The recommended best practices address the need for having information on hazardous chemicals available and provided to MDE, emergency responders, health professionals and the public. This will be accomplished by requiring the applicant for a drilling permit to submit Safety Data Sheets (SDS) to MDE and the local emergency response agency for every hazardous chemical that is expected to be on site at any stage of the operation. MDE will consider posting all of the SDSs on its website as a way of making the information available to persons living adjacent to the site and the public generally.

The required content of the SDS includes:

- *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*
3. A company should have to fully disclose the identity of all chemicals to be used in advance of their use.

The proposed best practice was to require disclosure of all OSHA hazardous chemicals. The Departments have reconsidered and will require the disclosure of all chemicals that the applicant expects to use on the site.

4. Disclosure should not be limited to OSHA “hazardous chemicals.”

The Departments agree and have altered the best practice.

5. After the well has been drilled and hydraulically fractured, a company should have to disclose the identity and amount of every chemical used. The information should be posted for each well on a publicly accessible and searchable website. Disclosure of chemicals on FracFocus is not sufficient, but it should be mandatory.

The permittee would be required to provide a complete list of chemical names, CAS numbers, and concentrations of every chemical constituent used in HVHF. If a claim is made that the composition of a product is a trade secret, the permittee must provide a list, in any order, of the chemical constituents, including CAS numbers, without linking the constituent to a specific product. This list will be posted on MDE’s website. The Departments will revise the best practice to require disclosure on FracFocus, so that the FracFocus data base can be more nearly complete and useful.

6. The State should require the use of unique tracer chemicals in hydraulic fracturing fluids that would allow identification of the source of any contamination. Currently, radioisotopes, nano iron, and DNA fragments are being examined as potential tracers. Although each approach has limitations and a timeline for effectiveness, they may be useful in detecting leaks and failures or accidents in the future.

Research is ongoing to identify potential tracers and evaluate their usefulness. In the future, the Departments will consider whether to require the addition of tracers to fracturing fluid.

7. If the companies refuse to list their proprietary chemicals then the State should mandate tracers to track the migration of and source of contaminants.

The proposed best practices would require companies to disclose proprietary chemicals or refrain from using them in Maryland.

8. Long-term monitoring of surface water and groundwater should be mandated for the tracer chemical and other constituents of fracking fluid. Groundwater moves very slowly.

The State agencies will develop standards for monitoring during operations at the site, including production.

9. Trade Secret issues

- a. The State should not recognize any claim of trade secret.
- b. If the State recognizes trade secrets, there should be a presumption against the claim of trade secrecy and the burden should be on the claimant to prove the claim by clear and convincing evidence. The State should develop an administrative mechanism by which any citizen can challenge a claim of trade secrecy.
- c. The State should provide a way for health professionals to access trade secret information simply and immediately.
- d. The use of confidentiality or non-disclosure agreements should be prohibited.

A trade secret is a kind of intellectual property and is protected by the Constitution. In addition, trade secrets and other confidential commercial information are protected by State statutes. The Departments are not free to make an exception for one type of trade secret. However, the best practices report recommended a process whereby the burden would be on the claimant to substantiate the claim. Even if the claim is valid, the applicant will have to disclose the identity of the trade secret chemicals to MDE. A process exists under the Public Information Act to challenge the withholding of a document on the grounds of trade secrecy.

The best practices also recommended rules for disclosure to health professionals similar to the rules applicable under the OSHA Hazard Communication Standard (HCS). According to the Maryland Occupational Health Division, the HSC has been used in Maryland without significant difficulties. Upon further consideration of comments, however, the Departments are revising the recommendation concerning disclosure to health professionals to reduce the burden on the health professionals to obtain the information and to allow the health professional to communicate the information to the patient and other health professionals. Disclosure to health professionals is not limited to those treating individuals; it can also be made available to epidemiologists and others with legitimate need. The best practices will be clarified on this point.

Confidentiality or non-disclosure agreements are necessary to protect legitimate trade secrets.

10. Fracking fluids should be tested before and after injection to establish toxicity and evaluate potential harm.

The potential harm of fracking fluids can be evaluated based on the chemical content, which will be disclosed to MDE with the application for a permit. As noted in the draft best practices report: "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, flow back contains significant concentrations of dissolved sodium, calcium, chloride, barium, magnesium, strontium, and potassium. It can also contain volatile organic compounds." Cuttings, flowback, 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. Otherwise, the flowback can properly be disposed of in injection wells.

At this time, Maryland does not allow flowback or produced water to be discharged to waters of the state, even with treatment. If EPA is able to develop pretreatment standards for these wastewaters, Maryland will consider whether to allow these wastewaters to be sent to a wastewater treatment plant.

THE COMPREHENSIVE GAS DEVELOPMENT PLAN

Regulatory process and mitigation

1. We concur with MDE's view that the CGDP should be mandatory in Maryland and its preparation is a prerequisite to an application for a well permit.

The Departments agree that the CGDP should be mandatory; however, for the reasons explained below, the Departments now propose to allow a limited number of exploratory well permits before the completion of the CGDP.

2. It is not clear whether the State can actually require a CGDP, or if the requirements will be undermined by judicial decisions. Without the CGDP, many protections will be lost.

The Departments believe that MDE has the legal authority to require a CGDP. The Departments agree that it is a key element to ensure adequate protection. If it were invalidated or rendered ineffective, the State would need to reevaluate the options for adequate protection and may decide that HVHF should not be permitted in Maryland.

3. According the draft report, "If the State determines that the CGDP conforms to regulatory requirements and, to the maximum extent practicable, avoids impacts to natural, social, cultural, recreational and other resources, minimizes unavoidable impacts, and mitigates remaining impacts, the State shall approve the CGDP." How will "the maximum extent practicable" be determined? The State should describe a threshold at which it would reject a CGDP if it determines that impacts are not sufficiently minimized or mitigated. How does the state plan to balance the various interests and determine if a plan "conforms to regulatory requirements and, to the maximum extent practicable?" Will the economic burden on an applicant be part of the determination?

It is not possible to establish a threshold of impacts that would require disapproval of the CGDP because every situation will be unique. Development and evaluation of the CGDP will involve a balancing of the interests of the local residents and community with the rights of property owners and leaseholders and impacts to the environment and public health. The engineering and operational standards will apply to all well permit applications, and will serve to control the impacts. The term "practicable" is sometimes interpreted as "that which can be done without undue hardship," so the economic burden on the applicant can be considered, but is not determinative.

4. Approval of a CGDP should not amount to a pre-approval of a gas drilling permit.

Approval of the CGDP is not pre-approval of a gas drilling permit; rather, approval of a CGDP is a prerequisite for the filing of an application for an individual production well permit, which must be at a location approved in the CGDP.

Decisions on applications for individual gas drilling permits will be made based upon the information submitted in the individual application and the applicable rules and regulations.

5. There should be no “fast tracking” of wetland and waterway permit approvals merely because the locations of wetlands impacts and waterway and floodplain impacts have been identified in a CGDP. Fast tracking and expedited review shortchange the local citizens.

For wetlands and waterway permit applications, the Department sometimes requires an alternatives analysis of the proposed project, including the "no action" and other alternatives that avoid and minimize adverse impacts on wetlands and waterways resources, with the analysis including an evaluation of alternatives that have the least impact on public safety, adjoining properties, and the aquatic environment. Although the CGDP will provide valuable information necessary for MDE's review of a wetlands and waterways permit application, additional information may be requested, on a case-by-case basis, related to the State's alternatives analysis or other information requirements regarding avoidance and minimization of impacts to wetlands and waterways resources. The CGDP does not in any way excuse compliance with any of the procedural or substantive requirements of the wetlands and waterways permits, and local citizens will be afforded all of their public participation rights.

6. When can the collection of the two years of baseline monitoring begin relative to the submission or approval of the CGDP?

The collection of the two years of baseline monitoring can begin at any time. Because the collection of this site-specific data will be expensive, it is unlikely that the applicant for a CGDP would begin this monitoring until the applicant was confident that the location of the drilling pad would be approved. The applicant could, however, take a chance on approval of the CGDP and initiate the baseline monitoring before submitting a CGDP for approval.

7. Can the applicant apply for an individual well permit immediately after approval of the CGDP?

The applicant can apply for an individual well permit for a well site in an approved CGDP, but the application will not be complete until the applicant submits the 2 years of baseline monitoring.

8. We believe that the development of a comprehensive gas development plan has the potential to not just protect natural, cultural, social and recreational resources, but it could end up saving the gas drilling companies significant development costs due to increased efficiency. In order to make the use of CGDPs more attractive to industry, particularly if CGDPs are not made mandatory, we would support the use of expedited permits and approvals.

The State expects that a high quality CGDP will minimize the need for costly and time consuming permitting processes by virtue of avoiding and minimizing many of the environmental impacts upfront. Although the CGDP will provide valuable information necessary for MDE's review of permit applications, additional

information may be requested, on a case-by-case basis. The CGDP does not in any way excuse compliance with any of the procedural or substantive requirements of other permit programs.

9. We would support the conservation of high value forest through easement or fee-simple acquisition as a mitigation option for implementation of the no-net-loss of forest recommendation given the lack of land in Western Maryland for reforestation. We would recommend that the definition of high value forest include inholdings within state forest lands, parcels surrounding existing large protected tracts of forest, and key connectors and corridors linking large forest blocks.

These are good suggestions and will be considered.

10. "Avoid, minimize and mitigate impact on resources as discussed in Section IV." Section IV does not address mitigation.

Each permitting program has specific mitigation requirements. In addition, the resource agencies work together to identify the most appropriate mitigation requirements based on the specific impacts. Mitigation is approached on a case-by-case basis to ensure that all impacts are adequately addressed.

Effectiveness

1. The study is unclear about how the cumulative impact of shale gas development by multiple companies will be considered in the review of CGDPs.

Even the first CGDP will provide more information about cumulative impact than any individual well permit application. Subsequent CGDPs will provide additional opportunities to evaluate and reduce the cumulative impact, for example, through co-location of infrastructure.

2. We support the recommendation for a Comprehensive Gas Development Plan (CGDP) to be prepared by the gas industry that plans for a development area prior to considering each individual well. Such an approach makes sense for maximizing efficiency and minimizing potential impacts to water quality of source and receiving waters.

The Departments agree.

3. Using a Comprehensive Gas Development Plan will concentrate the adverse impacts of shale gas development in a few places, creating intolerable levels of negative impact on those who live there.

The goal of the CGDP is to reduce the cumulative impact of shale gas development by minimizing the number of well pads, roads, and pipelines, and by locating these surface disturbances in areas that will be least impacted by them, considering both the ecological impact and the impact on people. The hypothetical "idealized example" presented in Figure 1-1 of the Eshleman report with 54 wells on 36 contiguous acres of pads is not a real world scenario, nor would it ever be permitted if it resulted in extreme impacts to residents or to a community. The process of developing and approving the CGDP will provide an opportunity for considering the

potential impacts of different development scenarios. Concentrated development will not be approved at the expense of the well being of residents.

4. Integrated CGDPs (involving more than one company) are merely encouraged, not required. This does not protect the public's interest.

One company may prefer to defer gas development in Maryland, while another wishes to move forward. It would not be fair to prevent a company from submitting a CGDP just because a competitor was not ready to proceed with development of its (the competitor's) holdings.

Mapping and Shale Gas Development Toolbox

1. The CGDP should require geological mapping to cover the potential existence of fault lines.

Most companies conduct various types of geological mapping prior to developing a drilling plan in order to determine where fault lines occur and how this will affect HVHF production rates. The Departments have decided that they will require, as part of the CGDP, that the applicant perform and submit a geological investigation to locate existing faults and fractures and abandoned wells in the area covered by the CGDP. A similar geological investigation may be required for the limited number of exploratory wells that may be permitted without a CGDP.

2. The CGDP will not be effective unless the data that goes into it is reliable. Data collected by the industry should be compared to data independently collected or confirmed by MDE and DNR, especially if two or more companies participate jointly in the development of a CGDP. Industry data should not be accepted without verification.

Most of the data to be considered for a CGDP will be data the State has collected and provided to the applicant and the public, including GIS data. The exceptions are that the applicant must also perform a rapid field assessment for unmapped streams, wetlands and other sensitive areas and submit a geological investigation to locate existing faults and fractures and abandoned wells in the area covered by the CGDP. The adequacy and reliability of that data will be considered by the Departments. The full Environmental Assessment will be done in connection with the application for individual well permits. There is no two year planning requirement for the CGDP; the application for an individual permit must include two years of background data.

3. The State should develop maps showing where Marcellus gas development, including ancillary operations, is and is not to be allowed. Wetlands, flood plains, steep slopes, rivers and streams, lakes, outcroppings, and local topographic features should be shown.

The Shale Gas Development Toolbox will include maps with a significant amount of information on these areas.

4. The Toolbox should include complete hydro-geological data for all fractured-rock strata over Maryland's Marcellus shale deposits, documenting location of underground aquifers and understanding their movements. To ensure accuracy

this data should not be collected by the applicant, but by contractors approved by or employed by the State.

This would be valuable information for all areas of the State, and some research along these lines was recommended in the reports of the Advisory Committee on the Management and Protection of the State's Water Resources. The research is expensive and has not been fully funded. The State is pursuing the studies in phases. As the information is developed, it will be published and potentially added to the Toolbox if it is suitable for such purpose.

5. The Comprehensive Gas Development Plan should also include a review of all past land uses, local and State Comprehensive plan consistency analysis and relevant information about local zoning and land development regulations.

Past land uses that include drilling or subsurface coal mining will help inform the CGDP and where this information is available, it will be provided. The Shale Gas Development Tool box will work with local governments to provide the appropriate links to program, zoning and land development regulations. The Toolbox may include mapping data from local governments if it is available.

6. MALPF preserved property and MALPF easements should be considered in planning and mapped in the toolbox.

This information will be included in the Toolbox.

Alternatives for exploratory wells

1. We need a set of temporary regulations that will allow for exploratory wells to quantify the quality and quantity of the gas underlying the shale play in Western Maryland.
2. The CGDP should be voluntary and should not apply to exploratory wells. It is not reasonable to require the development of an extensive plan for long term development in areas where there is no information on the viability of the project, or indeed if the Marcellus formation in the area would support such a development. It would also make sense to require some basic information before doing any initial drilling and then requiring a very detailed document before production can occur. If an exploratory well is allowed and it produces gas, it should be permitted for production.
3. While a CGDP is reasonable on extremely large acreages like the Pennsylvania state lands, no one in our organization can visualize how such a thing would work when a thousand landowners may be involved and there are no proven reserves here to encourage a company to engage in such a process. At the very least, the industry needs to be permitted to drill enough wells under temporary restrictions to prove the reserve before they are required to jump such a hurdle.
4. We have serious concerns about a mandatory Comprehensive Gas Development Plan (CGDP) for at least five years. This requirement is premature; requiring it after a company has drilled initial exploratory wells would make much more sense. Shortening the time frame to two or three years would also allow for more accurate forecasting. Bifurcating it to provide some basic information before

doing any initial drilling and then requiring a very detailed document before production can occur would be practical. It would also allow for a significantly more substantive and accurate long term CGDP being submitted.

5. Without validating the need for a mandatory CGDP, a more practical approach would be the permitting of one or more exploratory wells in accordance with current state regulations to allow operators the opportunity to determine the feasibility of further development. It should be noted that to begin the process of drilling an exploration well, the operator must dedicate approximately four years of resources and expense before obtaining any information on the viability of production from the Marcellus formations in Maryland. This timing assumes the noted policies, maps, and toolbox are in place.

Drilling and hydraulically fracturing an exploratory well would have impacts similar to drilling and fracturing a production well. Moreover, if an exploratory well shows good yield, it will probably be converted to a production well. For this reason, the Departments initially proposed that CGDPs should be required for any well – exploratory, offset or production. Commenters noted that basic information that can only be obtained by an exploratory well would be necessary before a company could write a CGDP. If a company were required to prepare a CGDP before drilling exploratory wells, there would be a high likelihood that the information obtained from exploratory wells would necessitate a substantively different CGDP. In the [informal solicitation](#)³⁰ of Commissioners on their reactions to the draft plan, 8 of the 12 Commissioners who responded indicated that it might be appropriate to allow a certain number of exploratory wells before requiring the submission of a CGDP.

The Departments are therefore proposing that one exploratory well can be drilled within a circular area having a radius of 2.5 miles centered at the exploratory well. The same location restrictions and setbacks required for siting production wells will be required for exploratory wells. No additional wells, exploratory or production, can be drilled within that area until a CGDP has been approved. Absent a determination by MDE that the exploratory well can be connected to a transmission line without any adverse impact on wetlands, forest, or nearby residents, the exploratory well cannot be converted to a production well until a CGDP for that area is approved.

CGDP timeframe

1. The CGDP adds a time consuming and expensive planning for a driller who may not even have obtained the leases, options, rights-of-way and other property rights. It may have minimal environmental benefit. The standards for approval are ill defined and the process could drag on and even be appealed to a court.

The State will provide criteria, mapping information and guidance upfront so that drillers will have all of the information they need to make wise real estate and leasing decisions. This should actually improve the ability of a driller to develop an acceptable plan and have it readily approved since there will no unanticipated conditions or constraints.

³⁰ www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Survey_Commissioners_Final.pdf

2. The time frame for a CGDP should be shortened to two or three years to allow for more accurate forecasting.

If exploratory wells are allowed without a CGDP, as described above, a five year timeline is not unreasonable.

3. Why should a CGDP that covers only five years of development remain in effect for ten years?

Many factors could cause a company to delay implementation of its CGDP. The Departments think that allowing 10 years is reasonable.

4. According to the UMCES-AL report the average well pad will be in place for at least 30 years. According to this report, the plans will remain in effect for 10 years. Five years does not seem sufficient given the long-term nature of this activity.

It is important to choose good locations for well pads because they will be in place for a long time. The CGDP will identify the locations of surface disturbances such as well pads, pipelines and roads. Permits to drill wells will only be approved if the locations are consistent with an approved CGDP. To establish new locations, the company would have to go through the CGDP process again.

5. The report indicates that an approved CGDP will remain in effect for 10 years. We recommend a provision for renewal be added to the report language.

The Departments agree that one renewal for an additional 10 years can be granted if the resource information is updated, and the locations initially approved do not violate any more recently enacted location restrictions or setback requirements. However, if a company has compiled a record of serious violations or has failed to remediate any spills or releases properly, MDE can deny a renewal request.

6. Agencies should review the approved CGDP plan at the 5 year point to ascertain whether any environmental conditions have changed that would require a CGDP modification.

While this might add additional environmental protection, its usefulness must be balanced against the legitimate need of a company to make long term plans. An approved CGDP will be a public document, and anyone undertaking activities in the area covered by a CGDP should be aware of it. In the event an application for an individual well raises serious environmental concerns, it may be possible to deny the permit or add protective provisions to the permit.

7. If one looks at the complete requirements to obtain a drilling permit, the permit would require the development and approval of a five year CGDP plan, followed by a lengthy approval process. The total time for the development and approval of a CGDP plan is estimated at a minimum of 18 months. Assuming approval of the plan, this would be followed by a minimum two years of pre-development baseline data collection (pages 44 and F-1) on groundwater, surface water, and both aquatic and terrestrial ecological resources prior to obtaining approval to drill the initial well. The total time to perform the baseline study and obtain state approval is estimated at 28 months.

It is unclear how the commenter arrived at a minimum of 18 months to develop and approve a CGDP. As currently proposed, the process gives the State 45 days to review the initial submission and provides a maximum 60 day period for facilitated stakeholder review. There may be additional reiterations of the planning, depending on the quality of the initial CGDP submission. Following the facilitated stakeholder review, there will be notice and a public meeting to present the CGDP. Following that, the applicant can present the CGDP to the Department for approval. The applicant is free to begin baseline monitoring before the CGDP is approved, but this would be a costly undertaking that may need to be repeated if the location of the pad were to be changed before final approval of the CGDP.

Public review process

1. The industry may ignore viable alternatives.

A reasonable number of alternatives should be considered, and reasons should be given for rejecting alternatives.

2. When does the stakeholder review of the CGDP begin relative to the agencies' initial review?

The State agencies and local government agencies will review the applicant's draft CGDP and provide comments to the applicant within 45 days. Following receipt of the comments, the applicant may wish to revise the draft CGDP. For this reason, the mandatory public review and approval process will not begin until the applicant informs the agency that the draft is ready for public review.

3. This stakeholder review should not take place only at the request of the applicant.

The stakeholder review process is mandatory. It will not begin, however, until the applicant informs MDE that the draft is ready for public review.

4. There should be adequate time for public review of the CGDP after the completion of the stakeholder group process, and the applicant should be required to provide notice to the public.

Notice will be given to the public that the CGDP is available for review and comment and the date of a public hearing at which it will be presented. A comment period of 30 days beginning with the publication of notice will be provided, but the Department of the Environment may, in its discretion, extend the comment period. Although the CGDP is not a "permit" because it does not itself authorize any activity, in general, under Section 5-204 of the Environment Article, the applicant for a permit pays the cost of the newspaper notice, and the Departments would anticipate that this would be the case for the CGDP.

5. Who will be responsible for determining who will be part of the "stakeholders group", how will stakeholders be identified, who will organize the meetings, and who will pay for the facilitated process? Does this include landowners on adjoining properties, who will also be adversely affected by noise, lights, air pollution?

We envision that DNR will be responsible for identifying the stakeholders, organizing the meetings, and selecting the facilitator. The costs will be borne by the company that submitted the CGDP.

6. Local planning, historic preservation, and heritage groups should be included as stakeholders.

For a specific CGDP, these groups would be considered stakeholders.

7. Requiring the local governments to respond to a plan within 45 days is too short.

The 45 day review period should be sufficient to allow for a preliminary review that would spot red flags like noncompliance with a county or town ordinance. Local government would be included in the stakeholder group and be able to participate in that process after the end of its preliminary review.

8. 60 days to review a comprehensive plan such as these with as many stakeholders as these is exceedingly and totally unrealistic. There needs to be a lengthier period of time.

With the toolbox information and a skillful facilitator, the review could very likely be completed in 60 days or less. If experience proves otherwise, the time could be extended.

9. This should include the statement –“minimization of impact on existing human population and existing concentrated human population centers” as part of the considerations.

The Departments agree that impacts to existing human populations and existing concentrated human population centers are extremely important to consider. Many of the setback requirements are intended to address these conflicts. The Departments also believe the inclusion of a facilitated stakeholder review and public comment period as a key step in the CGDP will provide an important venue to communicate these concerns to industry and to identify solutions that will avoid and minimize these impacts.

10. Allow applicants the opportunity to provide opportunities for meaningful public input in pre-development stages.

The CGDP requires a facilitated stakeholder and public review of the proposed plan. The State will review the submission in light of the stakeholder and public comments.

Planning principles

1. Will the State consider approving a CGDP near or adjoining state lines where regulations in the adjoining state do not meet requirements of Maryland’s CGDP process and regulations?

Maryland’s jurisdiction does not extend beyond State lines, and we would not expect a CDGP to address activities outside Maryland. Any CGDP for activities in Maryland will be considered on its merits.

2. The planning principles for the CGDP should not reference state policies that have not yet been enunciated, such as using directional drilling for stream crossings and siting compressor stations.

The State develops and revises many policies, and will continue to do so. We should not limit the planning principles only to policies that have already been developed.

3. The planning element “Sequence of well drilling over the lifetime of the plan that places priority on locating the first well pads in areas removed from sensitive natural resource values” is flawed. It implies that later wells can be located near sensitive natural resources.

There are setback requirements and other practices to protect sensitive resources. This planning element embodies the idea that, if we are to learn that any portion of the regulations should be changed as a result of incidents, we would prefer those incidents occur far away from sensitive resources.

4. We commend and strongly support the requirement for comprehensive gas development plans (CGDPs) to address siting issues at the landscape- or watershed-scale. The CGDP approach addresses environmental impacts at a regulatory scale appropriate to the state’s policy objectives; the alternative, piecemeal permitting, is inadequate for minimizing adverse landscape impacts. Further, comprehensive gas development planning is a necessary tool for minimizing habitat losses and fragmentation, two of our top priorities for better practices in the gas industry. In light of these considerations, we find it essential to establish the type of comprehensive, systematic approach outlined in Section III of the BMPs document.

The Departments agree.

5. We strongly endorse the Planning Principles set forth. These principles provide a proper framework for BMP development in the context of the charge in Executive Order 01.01.2011.11 to determine whether and how shale gas development in Maryland might be accomplished without unacceptable adverse impacts to public health, safety, the environment and natural resources.

The Departments agree.

6. The study proffers no Marcellus gas drilling on slopes greater than 15 percent; consideration should be given to using a range of 10 percent – 15 percent so assets and resources down-slope can be better protected.

There can be no drilling pad on land with a slope greater than 15 percent. The sites proposed for pads in the CGDP will be individually reviewed and slopes less than 15 percent will be evaluated for suitability.

7. The Comprehensive Gas Development is one of the most important and innovative aspects of the Commission’s report and addresses our organization’s concern for the landscape scale impacts of unconventional shale gas development. The Nature Conservancy’s Pennsylvania Energy Impacts Assessment released in 2010 highlighted these potential impacts and called for comprehensive planning to minimize these cumulative impacts. The need for landscape level planning has

also been identified by the Pennsylvania State University and the U.S. Geological Survey as important in controlling the impacts from shale gas development. We would urge that Comprehensive Gas Development Plans be mandatory and not voluntary.

The Departments agree.

8. The recommendation is to “submit a CGDP for the area where the applicant may conduct gas exploration or production.” We recommend that the area be defined as that which can be served by shared infrastructure without having to over extend that shared infrastructure to the point where it makes no economic or ecological sense.

While the State encourages companies to share existing infrastructure, it cannot force companies to participate with each other nor can the State restrict a company’s planning efforts to a specific geography.

9. It is not clear whether the 2 percent limit on surface development within a high value watershed applies to all development within the watershed or just the surface disturbance caused by gas development. If it applies to gas development over and above existing surface disturbance, high value watersheds that already have some development may be impacted even with the 2 percent limit. If this is the case, additional mitigation measures may be needed or that watershed should become off limits to gas development.

The recommendation of the UMCES-AL report that activities be limited to 1 to 2 percent of Maryland’s land surface has been widely misinterpreted. The actual recommendation was that “Cumulative surface development (including all well pads, access roads, public roads, etc.) could be maintained at less than 2 percent of the watershed area in high-value watersheds.” [UMCES-AL report](#)³¹ at 6-14. The State has limited land use authority; the authority to enact zoning, subdivision, and other land use restrictions lies with the counties and municipalities. Nevertheless, the Departments adopt this recommendation as a planning principle to be followed in the CGDP and to be used as a performance measure. The recommendation was based on empirical evidence that aquatic habitat and aquatic diversity become degraded by stormwater runoff well before the percentage of impervious surface reaches 10 percent and that brook trout are almost never found in watersheds where impervious surface exceeded 4 percent. The loss of some species, particularly stream salamanders, can occur in watersheds with only 0.3 percent impervious surface. The UMCES-AL research showed a relationship between the amount of impervious surface in a watershed and degradation of the stream. In order to provide an adequate margin of safety, UMCES recommended a 2 percent surface development threshold which they note can be achieved through the sensible application of best practices and comprehensive planning. The UMCES research relied in part on studies and analysis provided by the Department of Natural Resources:

- [Fact Sheet: Impacts of Impervious Land Cover on Maryland Streams](#)³²

³¹ www.mgs.md.gov/publications/report_pages/ADMIN_14-02-01.html

³² www.dnr.state.md.us/streams/pdfs/ImperviousFactSheet.pdf

- [S.A. Stranko et al. 2008. Brook Trout Declines with Land Cover and Temperature Changes in Maryland. North American Journal of Fisheries Management 28: 1223-1232.](#)³³

10. Maryland should not permit fracking to go forward in areas of the state, like Garrett County, where adequate land use protections are not in place.

This is a matter that should be addressed by local governments. The State agrees that local comprehensive planning and zoning could provide significant control over where HFHV occurs. The State has also proposed a rigorous set of best practices and setback restrictions that will be highly effective in minimizing harm to the environment, economy and public health.

11. (B), (4), “Preferentially locate operations on disturbed, open lands or lands zoned for industrial activity.” Departments should mandate that the state’s first wells be drilled in industrial parks to assure minimal land-use conflicts.

The Departments would prefer the first wells be drilled on the least sensitive lands but the State does not have the authority to mandate this.

12. It would appear useful, during both CGDP development and review, to consider the tradeoffs between trucking of water and use of water pipelines (e.g., traffic vs. land disturbance impacts).

The Departments agree that these issues should be considered at the CGDP stage.

13. The Pittsburgh-based Center for Sustainable Shale Development (CSSD) has generated an interesting “performance standard” which calls for establishment of an “Area of Review (AOR) ---which covers both the vertical and horizontal legs of the planned well.” Among other stipulations, the standard mandates “a comprehensive characterization of subsurface geology, including a risk analysis” as related to “confining layers” preventing “adverse migration of fracturing fluid”. [SOURCE: CSSD Performance Standards dated March 2013]. This “practice” is offered for consideration and relates to the controversy about possible migration of “bad stuff” to “good water” even from 6,000 to 8,000 foot depths.

Most companies conduct various types of geological mapping prior to developing a drilling plan in order to determine where fault lines occur and how this will affect HVHF production rates. The Departments have decided that they will require, as part of the CGDP, that the applicant perform and submit a geological investigation to locate existing faults and fractures and abandoned wells in the area covered by the CGDP.

14. Recent reports from western US fracking sites call our attention to the possibility of frack hits, blow outs that occur when a second drilling and fracking operation goes off course and leads into a drilling hole already in operation. The combined pressure results in the expulsion of fracking fluids under great pressure and spills occurring over a much wider area than would have happened if the second drilling

³³ http://clear.uconn.edu/projects/TMDL/library/papers/stranko_et_al_2008.pdf

operation had not "hit" the previously existing one. This calls into question the wisdom of the Report's siting of many multiple wells on one fracking pad.

The Departments understand that drillers carefully plot the locations of their vertical and horizontal boreholes reducing the risk that wells drilled from the same pad would touch. There is a risk that a well will be drilled and contact an historic well that has not been properly closed. By requiring the identification of historic and abandoned wells during the CGDP process, this risk can be reduced.

15. The State is proposing a planning principal that the drilling activities comply with local law and regulations, including zoning ordinances. Since the plan is reviewed by the State, how will this determination be made?

During the initial review of the CGDP, local governments will have an opportunity to review the plan to determine if the drilling activities comply with local law and regulations. In addition, when applying for an individual well permit, the applicant must produce written approval by the local zoning authority that all local planning and zoning requirements have been met. COMAR 26.19.01.06C(11).

16. Reduce land use conflicts with adjacent properties. Protect Maryland's prime agricultural soils and prime farmland.

Avoidance of prime agricultural soils and farmland is desirable, but it must be weighed against impacts on forests and sensitive ecological areas.

Compressor stations, gathering lines and other supporting infrastructure

1. Local zoning may not be honored because FERC can overrule local zoning by preemption.

The Federal Energy Regulatory Commission has jurisdiction over interstate gathering lines, transmission lines, compressor stations and storage facilities. The commenter is correct that FERC could overrule local zoning for the siting of those interstate facilities and infrastructure. FERC does not have jurisdiction over the locations of well pads or wells, or intrastate facilities.

2. Changing the location of a compressor station or pipeline should require a formal modification to the CGDP.

This is a complicated issue because of the shared federal and state regulatory authority over transmission lines and compressor stations. The Departments will inform FERC and the PSC of the role of the CGDP in Maryland's natural gas development regulatory process. Those agencies may not be bound by the CGDP, but will certainly consider the CGDP.

3. The agencies should adopt a clearinghouse strategy that would bring the PSC into the permitting process for the CGDP. The agencies and the MSAC should review the process for permitting, siting, construction and operation of all pipelines and ancillary development outside of the CGDP process.

The CGDP is not a permitting process, but rather a planning process for approving locations in advance of permitting. The PSC has no authority over the location of

pads or gathering lines. The commenter's suggestion goes beyond the scope of the Executive Order.

4. I advise caution on location of pipelines along roads because of the explosion hazard.

The explosion risk of properly installed and maintained underground pipelines is low.

Modifications to the CGDP

1. If the applicant increases its total surface disturbance by 20 percent or greater the applicant should be required to resubmit their application for the CGDP and begin a new the process. Those applicants that increase their operations by less than 20 percent should be allowed to modify the existing application.

The CGDP will establish the locations of the pads, pipelines and roads, but will not specify the details, such as the area covered by the pad or the width of the road, except where those details are necessary to assure that harm is mitigated to the maximum extent practicable. The draft best practices report recommended that "Significant modification to the original plan, such as a change in location of a drilling pad, or the addition of new drilling pads, will require the submission and approval of a modified CGDP application. Modifications that cause no surface impact, such as the installation of additional wells on an existing pad or a change in the sequence shall be approved by the State upon request of the applicant." If the applicant disturbs more surface by widening a road, for example, there would be no need to modify the CGDP unless the width of the road had been established to protect a sensitive area. The Departments judge these to be reasonable provisions.

2. Adding wells to a pad should require a formal modification to the CGDP. Additional wells on a pad would still have greater social and environmental impact and could create intolerable levels of negative impact on those who live in the "sacrifice zones."

Any new wells added to a pad will require the filing of a new individual well permit application which would include a public comment process to address the concerns of the affected, nearby residents.

CONTAMINATION OF DRINKING WATER

1. Any spills could contaminate surface and subsurface drinking water supplies. The National Forest Service will likely ban fracking in the George Washington National Forest, which lies in the Mountains of Virginia and West Virginia. The reason: There is enough evidence to suggest that the process and the potential for spills poses risks to the drinking water supply for millions of people, including those living in the Washington, DC. (Article)

Spills from fracking operations could potentially contaminate surface and subsurface water supplies, so it is very important to prevent spills, contain them if they occur, and clean them up. Each applicant for a permit will have to submit a detailed spill prevention, control and countermeasure plan and an emergency response plan. The approved plan will become part of the permit, if it is issued. Many of the best practices also operate to reduce the probability of a spill. Examples are the

requirement to store wastes in tanks with secondary containment rather than in ponds.

The location restrictions and setback distances are also designed to protect drinking water. The Departments proposed significant setbacks in the draft report, and are adjusting some setbacks based on comments and further consideration.

The new requirement is that a well pad cannot be located:

- a. Within 1,000 feet of a wellhead protection area or a source water assessment area for a Public Water System (PWS) for which a Source Water Protection Area (SWPA) has been delineated. [Note that a similar setback is already in effect for wellhead protection areas. COMAR 26.19.01.09G]*
- b. Within 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).]*
- c. Within 2,000 feet of a private drinking water well; except that the well pad may be located between 1,000 and 2,000 feet of a private drinking water well if the applicant demonstrates through a hydrogeologic study that the proposed well pad is not upgradient of the private drinking water well and the owner of the private drinking water well consents.*
- d. Within 450 feet of any other stream, river, seep, spring, lake, pond, or reservoir from which drinking water is drawn.*
- e. Within the watersheds of any of the following reservoirs:*
 - i. Bradford Lake*
 - ii. Piney Reservoir*
 - iii. Savage Reservoir*

Based on further review, the Departments have decided to establish a setback specifically for springs that are the source of domestic drinking water to the residents of the property on which the spring is located. The setback, measured from spring to the edge of the well pad, shall extend to all lands at an elevation equal to or greater than the spring discharge elevation, but not to exceed 2,500 feet unless a delineation of the recharge area prepared by a registered geologist, with a report and data supporting an alternate area, is submitted to the Department and the Department approves an alternative area.

The Departments are also clarifying that no surface disturbance (road, well pad, pipeline) may occur within Maryland's State Parks, Forests, Natural Areas, Wildlands and other DNR land units without the permission of DNR. These lands were acquired by the State for their particular value and are managed for public purposes, including maintaining, enhancing and protecting sustainable and diverse wildlife populations, habitats, natural communities and ecologically sensitive areas,

biodiversity, rare, threatened and endangered species, wildlife-dependent recreation and other outdoor recreational opportunities. They also serve as a venue to educate citizens on the value and needs of wildlife and plant communities. State forests help reduce air pollution and protect our surface water and groundwater. All of these public purposes will be compromised if surface disturbance were allowed in these DNR-managed lands.

2. Methane concentrations in groundwater are higher near natural gas wells.

A recent article, A geochemical context for stray gas investigations in the northern Appalachian Basin: Implications of analyses of natural gases from Neogene-through Devonian-age strata, Baldassare et al., AAPG Bulletin, (February 2014), stated in the Summary and Conclusions section:

Reports of alleged stray gas migration can be the result of preexisting, and previously undiagnosed, methane in the shallow aquifer system, or the result of gas well operations, or other anthropogenic activity. Gas concentration variability in a water well over time can be the result of changes in hydrostatic head induced by pumping or by seasonal fluctuations in the water table. Alleged incidents of stray gas migration require investigations at the site specific level and evaluation and synthesis of multiple data types to determine the source of the stray gas. Site-specific investigations should include definition of gas and groundwater geochemistry and mechanism of migration. Comprehensive predrill groundwater quality sampling is often essential to distinguish preexisting natural gas in the aquifer systems from gas-well activity-induced stray gas migration. Alleged stray gas migration incidents must be monitored and sampled sufficiently following specific methodologies and investigation protocols to determine if the alleged incident is a natural condition or the result of natural gas-well activity.

The Departments are aware of the peer-reviewed scientific journal articles which report water quality data and assess whether there is a correlation between the concentrations of methane and dissolved metals in well water and distance from gas wells. Some of the articles show a statistical correlation and some do not. For example, Dr. Avner Vengosh, in his presentation at the April 14, 2014, meeting of the Advisory Commission, noted that he found no correlation between methane levels and proximity to gas wells in Arkansas, but that he did find increased stray gas abundance in drinking water wells within a kilometer of active gas wells in a part of northeastern Pennsylvania. Based on isotopic fingerprinting and other factors, he concluded that water wells near gas wells in northeastern Pennsylvania contained Marcellus production gases or a mixture of Marcellus gases and other gases. He wrote: "In cases where the composition of stray gas is consistent with the target shale formation, it is likely that the occurrence of fugitive gas in shallow aquifers is caused by leaky, failing, or improperly installed casings in the natural gas wells. In other cases, hydrocarbon and noble gas data also indicated that fugitive gas from intermediate formations apparently flowed up through the outside of the well annulus and then leaked into the overlying shallow aquifers." Vengosh et al., A Critical

Review of the Risks to Water Resources from Unconventional Shale Gas Development and Hydraulic Fracturing in the United States, *Environmental Science and Technology* (2014).

It is known that methane can appear in drinking water wells in western Maryland without any relationship to gas wells. The Maryland Geological Survey (MGS) recently performed a pilot study to determine background (before horizontal drilling and hydraulic fracturing) methane levels in drinking water wells in Garrett and Allegany Counties. The results are consistent with other reported data that shows a relationship between topography and methane content. MGS categorized wells as 1) in valleys in coal basins; 2) on hilltops or hillsides in coal basins; 3) in valleys but not in coal basins; and 4) on hilltops or hillsides but not in coal basins. The authors report:

With respect to the four well-location categories targeted in this study, ... valley wells in coal basins had the highest proportion of detections (11 of 15 wells, or 73 percent), followed by coal/hilltop+hillside (9 of 20 wells, or 45 percent), non-coal/valley wells (7 of 17 wells, or 41 percent), and non-coal/hilltop+hillside wells (7 of 25 wells, or 28 percent).

The authors also sampled a small number of wells approximately monthly, and found that “The average percent difference from the median monthly methane concentration in each well was between 20 and 30 percent, although individual variations in each well were frequently larger.”

The Vengosh data present a convincing case for contamination of shallow drinking water aquifers by stray gas within 1 km of active Marcellus wells in certain areas of northeastern Pennsylvania. Data from Arkansas indicate that methane concentration in shallow drinking water aquifers does not show an increase with proximity to natural gas wells. During the Advisory Commission’s April 14, 2014, meeting Dr. Vengosh said he does not know why methane is higher in drinking water wells near gas wells in Pennsylvania, but not in Arkansas. The wells were operated by different companies. In Pennsylvania air drilling has been used instead of drilling with mud because it is faster; he speculated that mud drilling may result in better casing and cement. There are geological differences, but there is no strong evidence to say whether the difference lies in better practices or different geology.

If practices lessen the chance of methane release, a combination of practices and setbacks could work together to protect shallow drinking water aquifers. The Departments are proposing specific well casing, cementing, testing and repair best management practices to minimize the rate of well failure and the associated potential for methane migration. These, combined with a significant setback and monitoring requirements, are appropriately protective of drinking water wells.

3. Naturally fractured shale is not an impermeable layer, as claimed by industry.

Marcellus shale is porous as evidenced by the fact that methane and other gases are held within its pore spaces. Any fractures occurring within a shale bed, whether

natural or induced through HVHF, will increase the ability of shale to transmit gases and liquids.

4. Research suggests that the treatment of shale gas waste by treatment plants raises downstream Cl^- concentrations but not TSS concentrations, and the presence of shale gas wells in a watershed raises downstream TSS concentrations but not Cl^- concentrations.

The discharge of shale gas wastewater through municipal wastewater plants in Maryland is not currently allowed. If EPA adopts pretreatment standards for shale gas wastewater, MDE will reconsider whether it should be permitted. Removal of dissolved solids, including Cl^- , is a necessary treatment step if fracking wastewater is to be discharged to freshwater surface waters.

An increase in total suspended solids is a likely consequence of sediment transport from disturbed land. Given the infrastructure needed to support shale gas development, it is imperative that proper care and planning go into developing an efficient network of pipes to collect gas with minimal disturbance to the landscape. Existing roadways and other rights of way should be used to the fullest extent possible. Proper erosion and sediment controls will also help reduce the transport of sediment from the construction site.

5. Currently available data indicate that the depth to the base of fresh-water aquifers in Garrett County varies greatly, from 400 ft to more than 1,000 ft below land surface, and it is not possible to predict with any confidence a depth to the base of fresh ground water at any given location. Therefore, we strongly recommend that this depth should be determined at each drill site. The best way to determine the depth to base of fresh water is to drill a pilot hole and run a suite of geophysical logs (including but not limited to electrical resistivity, porosity, and spontaneous potential logs) that can be used in conjunction with other well data to accurately characterize the subsurface fluids. In order to determine the base of the deepest fresh-water aquifer at each site, it is recommended that a vertical pilot hole be drilled and evaluated at each drilling site and that appropriate geophysical logs be run in the hole. This determination is best made in a small-diameter hole to minimize effects of drilling fluids on the measurements. If a separate pilot hole is not drilled, then at a minimum, the BMPs should specify that geophysical logging must include all zones from the bottom of the well to the ground surface (to ensure that logging covers the relatively shallow portions of the hole, not just the gas-bearing sections).

The Departments support the practice of drilling a pilot hole as a way to detect large underground voids and other subsurface characteristics such as depth to the base of fresh-water aquifers. One pilot hole per pad will be required as a prerequisite for drilling. This pilot hole needs to be fully cased or properly abandoned to ensure pathways between shallow and deeper aquifers are not introduced.

Current Maryland regulations require that the driller, when drilling the gas well, conduct an electrical induction and gamma ray log to determine depth of fresh water zones. COMAR 26.19.01.100. This requirement will be retained.

6. The majority of “wastewater” remains underground and the poorly understood technology for rock fracturing leaves us vulnerable to polluting our aquifers. The report does not address in any way if such introduction into the aquifers could ever be alleviated.

The available scientific evidence indicates that the possibility that fracturing fluids would migrate upward through the overlying rock formations to reach drinking water aquifers is extremely remote. In a highly faulted area, the risk would be higher, but would still be low, and in the presence of numerous abandoned wells, the risk could be appreciable. The Departments proposed in the draft report that maps of abandoned gas wells be consulted as part of the CGDP process. Because not all such gas wells and all faults are known, the Departments have decided to require a geological survey of the area covered by the CGDP to help identify them. At a minimum, the geological survey will include location of all gas wells (abandoned and existing), current water supply wells and springs, fracture-trace mapping, orientation on the location of all joints and fractures and other additional geologic information as required by the State.

7. Recent studies by Duke University researchers have verified by isotopic fingerprint methodology that methane gas migrates upwards through fractures from in the Marcellus formation in Pennsylvania water wells located within one kilometer of natural gas wells and contaminates water wells and aquifers. The Departments must review and significantly enlarge their setback requirements. More importantly, we strongly support programs to require the development and continual evaluation of baseline data on methane in water wells and aquifers in Western Maryland including the isotopic fingerprint of the methane. We believe that the need to pretest water well and aquifer samples within a kilometer of leased mineral rights for a number of elements along with isotopic fingerprinted methane must be made a requirement of MSGD and to continue periodically over the life of the well.

See answer to comment 2. Pre-drilling and post-drilling monitoring will be required. Isotopic analysis for methane can only be performed if there are high enough concentrations of methane. It will be required if circumstances warrant.

8. Gas migration from the Marcellus formation may be followed by brine containing liquids in the future that contain any number of elements and radioactive isotopes to further contaminate water wells and aquifers.

There is some evidence from areas in northeastern Pennsylvania that, unrelated to any gas well activity, deep brines may have mixed with shallow aquifers, suggesting a natural hydrogeological connection between the shallow and deep aquifers.

Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania, Warner, et al. (PNAS 2012). In his review article, Dr. Vengosh states that it is conceivable that stray gas from Marcellus wells could potentially be followed by a flow of hydraulic fracturing fluids and saline formation waters to overlying shallow aquifers. He noted, however, that "groundwater sites in areas affected by stray gas contamination near shale gas sites in northeastern PA have not to our knowledge shown signs of salinization induced directly by leaking

natural gas wells" and that further study would be needed. A Critical Review of the Risks to Water Resources from Unconventional Shale Gas Development and Hydraulic Fracturing in the United States, Vengosh et al. (Environmental Science and Technology, 2014, section 2.2)

9. The Departments should require monitoring of all water wells within 2500 feet of a vertical borehole before, during and after drilling and operation.

In the Eshleman Report, Recommendation 3-C of paragraph Q (page 4-32) and paragraph B in Section 4 (pages 4-6 and 4-7) support monitoring within 2500 feet of drilling activity. The Departments propose to accept this recommendation. The recommendation clearly requires pre and post drilling testing. Requirements for monitoring during drilling and during gas production will be included in the well permit. Additional monitoring is likely to be required if there are observed changes in water quality or evidence of a release of contaminants.

10. If more than one industry operator is working in the same area, the problem becomes more complex in assigning responsibility for a groundwater contamination and could lead significant delays while trying to establish responsibility. Possible solutions:
 - a. require the industry to develop the hydrology data for the areas in which they have lease holdings;
 - b. develop aquifer data at each well site
 - c. use tracers that are unique to each operator.

Because multi-well pads are common, it is unlikely that two different operators would be within 2500 feet (the presumptive impact area) of a drinking water well. If this situation were to develop, the presumption would apply to both companies. The Departments are now proposing to require applicants for CGDP approval to do a geological investigation of the area covered by the CGDP to locate existing faults and fractures, as well as abandoned wells. Research is ongoing to identify potential tracers and evaluate their usefulness. In the future, the Department of the Environment will consider whether to require the addition of tracers to fracturing fluid.

11. We believe that liability of water well contamination within 2500 feet of a drilled gas well must be incorporated into the permitting process and the time period extended beyond one year of the drilling activity to ensure water quality and public health are protected. A process must be developed to deal with and assign responsibility for unexpected problems especially if more than one industry operator is working in the same area.

The General Assembly limited the presumptive impact area to 2500 feet and 365 days after the last event of well drilling, completion, or hydraulic fracturing. Outside of that time and distance, a person would have to demonstrate that the contamination was caused by the actions of one or more gas operators. Under the severance tax bill (SB535) that was introduced in the General Assembly in 2014, MDE could use the proceeds of the severance tax to address immediate threats to public health or welfare, and seek compensation afterwards. The bill did not pass, but the

Departments will continue to search for ways to avoid the potential problem cited by the commenter.

12. Allowing the oil and gas industry to ride out this fracking treadmill in Maryland would turn the state into a pincushion of fracked gas wells. Over years and decades, these wells would age, degrade and be abandoned, creating pathways through which injected chemicals and natural contaminants can seep into underground sources of drinking water.

Maryland's best practices and financial assurances would ensure proper closure of all depleted wells.

13. The Culpeper Basin underlies the Poolesville Area Sole Source Aquifer, the primary source of drinking water for the area, as well as geological formations such as the shale barrens, the serpentine barrens and the diabase bedrock formation, which provide rare and unique habitats within Montgomery County. Protection of such resources are included in our local land use, zoning, and forest conservation codes and laws. Currently, hydraulic fracturing is not an allowed use in Montgomery County. As part of the Marcellus Shale Safe Drilling Initiative, we request the addition of a statement to indicate that the State will not seek to preempt local zoning and land use controls.

Current Maryland law requires MDE to deny the permit if the applicant has failed to receive applicable permits or approvals for the operation from all State and local regulatory units responsible for air and water pollution, sediment control, and zoning (Environment Article, § 14-108). Similarly, the regulations require the applicant to submit written approval by the local zoning authority that all local planning and zoning requirements have been met (COMAR 26.19.01.06C). There is no proposal to change these requirements.

14. The report specifies that the vertical casing extend below the “deepest known stratum bearing clear water” by a minimum of 100 vertical feet. This vertical distance seems small. Casings should extend at least below the brine level, and we’ve seen a study for the European Commission calling for a large distance of 600 meters (1,950 feet).

Only the surface casing is required to be run and permanently cemented to a depth of at least 100 feet below the deepest known stratum bearing fresh water. Intermediate casing and production casing must be cemented to isolate other fluid (liquid or gas) bearing formations.

15. The setback distances in general sound okay, but when dealing with drinking water reservoirs, such as the Frostburg Reservoir and others in Garrett County, the distances should be greater than those recommended by Eshleman and Elmore. If horizontal boreholes can extend 7000 feet, I think that the setback distance from key drinking water resources should be at least 7000 feet.

Upon reconsideration, the Departments have decided that a well pad may not be located anywhere within the watersheds of any of the following reservoirs: Broadford Lake (serving Oakland); Piney Reservoir (serving Frostburg); or Savage Reservoir (serving Westernport). It is the activity that occurs at the well pad that has the

greatest potential to release pollutants that could contaminate drinking water. In his presentation to the Advisory Commission, Dr. Vengosh said that there is no evidence so far of contamination of drinking water by the upward migration of fracking fluid or flowback, nor evidence of saline contamination of drinking water that might be an early indication of such migration. Evidence indicates that a vertical separation of the order of 2,000 feet would result in a remote risk that properly injected fluid would result in contamination of fresh groundwater. Because the separation between the bottom of the reservoirs and the laterals that might be drilled in the Marcellus shale is greater than 2,000 feet, the laterals need not be setback from sources of drinking water.

16. The UMCES-AL report states that, since the freshwater/saltwater interface has not been mapped in Maryland, the prudent approach would be to rely on the 2,000 ft criterion to provide an adequate margin of safety. Specifying vertical depth offsets presumes that the physical characteristics of geological units remain unchanged. Assuming such a statically safe buffer zone is questionable. Changes in the vertical permeability will occur and cannot be ignored. This occurrence is dynamic because the changes migrate upward with time.

The instrumentation used during the drilling of the pilot hole will measure the freshwater/saltwater interface. It can also be measured in drilling individual gas wells. There is no evidence that changes in the geologic structure in the estimated range (200 ft – 2000ft) of the freshwater/saltwater interface will occur.

ENVIRONMENTAL ASSESSMENT AND ENVIRONMENTAL IMPACT STATEMENTS

1. The preliminary Environmental Assessment for the CGDP addresses the ancillary facilities as well as the well pad, but the Environmental Assessment for the individual well permit addresses only the well and well pad. The ancillary facilities will escape full environmental assessment under Env. Code Section 14-104. The indirect and cumulative impacts of ancillary facilities and infrastructure, such as gathering lines, compressor stations and interstate pipelines should be considered, even though the state does not currently have the ability to regulate these.

Under the proposed best management practices a CDGP must be approved before any permit can be issued for a well. The purpose of the CGDP is to evaluate and minimize the cumulative impacts associated with all aspects of unconventional gas well development, including ancillary infrastructure. Practices such as sharing infrastructure and ancillary facilities, where possible, within and between various drilling companies will be required. The CDGP process therefore ensures that cumulative impacts are addressed in advance of permit issuance for any individual well site.

2. It appears that a full environmental assessment may not be required for both the CGDP and the individual permit.

Many of the current requirements for the State's environmental assessment will still be addressed by the CGDP in addition to the full environmental assessment required with any permit application.

3. The CGDP must be similar to a full Environmental Impact Study (EIS) which takes cumulative impacts and viewsheds into account, rather than a form of abbreviated Environmental Assessment.

Similar to an EIS, the purpose of the CGDP is to reduce or minimize cumulative impacts to surface waters, ground water, development projects, conservation activities, and other natural, social, cultural, and recreational activities. By examining the impacts and considering alternatives, the best locations can be identified. Though the minimum recommended setback for Marcellus shale drilling related infrastructure is 300 feet, additional setbacks will be considered to protect viewsheds. The State also anticipates that the CGDP process will be iterative in that a series of alternatives will be considered and stakeholders will be consulted before a final plan is approved.

4. The State has acknowledged that the current guidelines for an Environmental Assessment are inadequate. The State should require the same type of statement of environmental impact for all unconventional natural gas development as it does for leasing of state land for drilling.

The legislature established standards for the decision to lease State land for oil or natural gas production that are different from the standards for issuing a permit for an oil or gas well. Section 5-1702 of the Natural Resources Article requires that Board of Public Works request State agencies to prepare an environmental, fiscal, and economic impact statement before it may solicit bids for or award any lease for production of oil or natural gas from beneath lands or waters of the State. In addition, the production activities must adhere to all federal, state and local environmental laws. Section 14-104 of the Environment Article requires an applicant to submit an environmental assessment for the purpose of evaluating an application. The distinction between these two laws is that they are established for different purposes and move through different decision processes.

State lands owned by DNR are acquired and managed for their high conservation values, sensitive natural resources and their public benefits. These are public assets held in public trust, and as such, the Board of Public Works requires the additional information established by Section 5-1702. The revised permitting process proposed by the agencies, which includes revision of the environmental assessment guidelines and requires the development of a Comprehensive Gas Development Plan, will produce comparable assessments. The Comprehensive Gas Development Plan addresses area-wide environmental impacts of multiple well pads and includes a rigorous multi-agency and stakeholder review. Concurrent with this review will be an analysis of impacts and alternatives. Similar requirements are associated with the many permits required for an individual well. There will be more similarities between these two review processes than dissimilarities once the regulations are revised.

5. Are there regulations for basic requirements for an environmental assessment?
Are the requirements similar to NEPA?

Maryland regulation does not lay out the specific items that must be addressed by any environmental assessment. These are contained in guidance that will be updated. Environmental assessments go through a public process as part of the permitting process whereby stakeholders can ensure they are complete.

While titled the same in the current Maryland "Application to Drill," the state's environmental assessment is not related to the Environmental Assessment required under NEPA. State regulations do not require either an Environmental Assessment (EA) or Environmental Impact Statement (EIS) as defined under NEPA for gas well permits. The proposed requirement of a comprehensive drilling plan as a Best Management Practice for natural gas development in Maryland, however, will address some of the significant environmental factors, including cumulative impacts that are the core of the NEPA EIS and EA processes. Additionally, the current state regulatory processes that control the specific activities required for production and transportation of natural gas, e.g. wetlands and waterways permits for stream crossings, not only require an assessment of environmental features as part of the application process, but also function to protect environmental assets.

6. The Environmental Assessments should include an analysis of alternatives and past land uses.

The Comprehensive Gas Development Plan, as recommended, will include an alternatives analysis. Historic wells will be identified and setbacks observed. The recommendations for the CDGP also require a consideration of identified historic cultural resources.

7. I know that the natural environment, is a focus of the Department of Natural Resources, but there seems to be more concern with the survival of small populations of endangered species, than we do about the disrupting the lives of people.

The Department of Natural Resources recognizes that there are many irreplaceable resources that could potentially be impacted by unconventional gas well development that include sensitive habitats, plants and animals, and, just as importantly, the health and quality of life of the affected people. DNR is committed to working with the Maryland Department of the Environment and other state and local government agencies to avoid and minimize all of these impacts, should the decision be made to proceed with Marcellus development. Also, as part of Governor O'Malley's Executive Order, the Departments must undertake public health and economic studies to evaluate the impacts of Marcellus shale gas drilling on the community. In addition, both noise and road traffic are considered in Maryland's best management practices and more stringent provisions may be included in permits to address site-specific conditions.

8. The Government Accountability Office could not quantify the risks of shale gas development because (1) it couldn't predict where the wells would be constructed; (2) not all operators use best practices to the same extent; (3) there

are few studies comparing pre- and post-development conditions; (4) changes to laws and regulations will affect future activities; (5) risks will vary across business practices, which may vary among companies. Without this, GAO could not conclude that fracking is “safe.”

The GAO took a nationwide view and therefore was considering a patchwork of different state programs. This variability in regulatory programs between the states makes it difficult to assure that adequate safeguards are in place nationally to address risks associated with unconventional gas well development. Maryland specifically, however, is conducting a risk assessment in order to determine where the greatest risks to human health and the environment exist in order to focus our efforts to minimize these risks. This is in addition to the following actions taken to address the stated concerns:

- (1) The State is requiring various setbacks to protect human and environmental health as well as requiring the CGDP which considers cumulative impacts across the landscape;*
 - (2) The State has developed a uniform set of best management practices to protect human health and the environment as well as a compliance program intended to ensure consistency with required BMPs that are a part of the approved permit;*
 - (3) The Departments recommend requiring 2 years of pre-development baseline monitoring and continued monitoring after development begins. MDE and DNR will use such monitoring data to help identify whether negative impacts have occurred as a result of drilling activities. This is in addition to a baseline monitoring network (both ground and surface waters) already put in place during 2013.*
 - (4) Any changes to laws will only serve to strengthen, not undermine, all of the protective measures Maryland is putting into place; and,*
 - (5) Again, and as stated above, Maryland is developing both best management practices and a compliance program to minimize risks associated with unconventional gas well development.*
9. The minimum 2-year pre-development baseline data needs to be a mandatory part of the CGDP or the Departments need to require a comprehensive Environmental Impact Statement (EIS) to compile baseline data to assess cumulative impacts and mitigation strategies.

The 2-year pre-development baseline data is a mandatory element of the individual well permit. An application to drill a well is not complete until the baseline data has been collected and submitted to the State. It should not be made a mandatory element of the Comprehensive Gas Development Plan, because the purpose of this plan is to identify appropriate well pad locations. This will allow industry to initiate pre-development baseline monitoring in a timely manner as a precursor to filing a permit.

EARTHQUAKES

1. Fracking causes earthquakes

- a. The independent studies conducted by University researchers across the state of Texas have determined that fracking causes earthquakes of 4.0 and higher within miles of fracking sites. Insurance companies do not cover earthquake damage in Maryland.
- b. Hydraulic fracturing has been definitively linked to earthquakes in Ohio.
- c. Fracking by its very nature brings an increased incidence of earthquakes, even in areas of the world where earthquakes had been nonexistent. Fracking drills a series of deep holes in the earth's crust and in so doing creates areas of weakness. Frequent earthquakes result in many areas where extensive fracking has taken place. Recently fracking was discontinued in the United Kingdom because of earthquake occurrences.

The act of fracturing and propping open the fractures in the Marcellus Shale beds will create microseisms (faint earth tremors), just as activities at quarries throughout the State do. However, these microseisms typically are not felt nor do they cause damage. Both the Texas and Ohio earthquakes have been definitively linked to well injection sites, not fracking wells. As explained in a recent "[Man-Made Earthquakes Update](#)"³⁴ from the United States Geological Survey (USGS),

Many questions have been raised about whether hydraulic fracturing — commonly known as “fracking”— is responsible for the recent increase of earthquakes. USGS’s studies suggest that the actual hydraulic fracturing process is only very rarely the direct cause of felt earthquakes. While hydraulic fracturing works by making thousands of extremely small “microearthquakes,” they are, with just a few exceptions, too small to be felt; none have been large enough to cause structural damage.... [U]nderground disposal of wastewater co-produced with oil and gas, enabled by hydraulic fracturing operations, has been linked to induced earthquakes.

An investigation has begun of earthquakes that occurred in early March 2014 in Ohio to determine if they could have been caused by hydraulic fracturing. The Departments will follow this investigation closely.

Underground disposal of wastewater from oil and natural gas production occurs in Class II injection wells. There are no Class II injection wells in Maryland and none is being considered.

Earthquake insurance is offered as a rider just as flood insurance is offered as a rider in Maryland. This is typical nationwide.

Fracking was suspended in the UK for about one year due to safety concerns. An expert panel reviewed the information and concluded that fracking could continue with the existing regulations in the UK. This suspension ended April 2012.

³⁴ www.usgs.gov/blogs/features/usgs_top_story/man-made-earthquakes/

Additional information can be found in these articles:

Kim, Won-Young, "Induced seismicity associated with fluid injection into a deep well in Youngstown, Ohio." Journal of Geophysical Research v118:7 (2013), p.3506-3518.

Frohlich, Cliff, "Two-year survey comparing earthquake activity and injection-well locations in the Barnett Shale, Texas." Proceedings of the National Academy of Sciences of the United States of America. DOI:10.1073/pnas.1207728109.

2. The report lacks any substantive analysis regarding potential risks of fracking and geologic faults. Seismic events can release the fracking fluids that are intended to be contained.

All known geologic faulting in Garrett County is 250 million years or older. Faults this old are generally not seismically active.

3. Pre-existing planes or surfaces of weakness within the overlying shale influence the direction of upward fracture migration. The next earthquake could be triggered when the upward migration of a zone of fractures or enhanced porosity intersects the plane of an active fault zone and then follows this plane of weakness preferentially. This would essentially "lubricate" the opposing faces of the fault and trigger the next earthquake.

The Departments acknowledge that pre-existing faults and strata discontinuities have the potential to conduct or allow migration of materials along those fault lines. The Departments do not concur that any migration of fluids would lubricate the historic fault structures that have been inactive for 250 Million years.

EMERGENCY RESPONSE

1. Under the BMPs, company emergency response plans must include information on specially trained crews that can arrive within 24 hours of a blowout, fire or other accident.
 - a. Twenty-four hours is an eternity when a high-pressure drilling operation malfunctions and toxins are spewed freely. That BMP is insufficient to protect everything in the well's path: workers, nearby residents and the environment.
 - b. The BMPs should require plans for a 12 hour emergency response plan as 24 hours is much too long in case of a blowout, fire or other accident.
 - c. Maryland should require an eight (8) hour or less response to an incident.
 - d. The 24-hour emergency response by drillers is irresponsible and inadequate and all drillers should have methods in place locally to fix issues within a 4-hour timeframe.
 - e. Trained crews should be required to arrive immediately.

The draft best practices report stated 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. Before any drilling is permitted, local emergency response personnel will receive training so that, in the event of an emergency, they can remove the injured and secure the area until specially trained personnel can arrive. In the event of a release of pollutants that may pose a risk of harm to nearby residents or buildings, they will assist in evacuations. It is likely that company personnel will be present or nearby and able to manage the incident. In the event of a well blowout, fire, or other incident that personnel at the site cannot manage, the operator must be able to have specially trained and equipped personnel at the site within 24 hours.

Emergency response personnel at MDE have initiated discussions with county personnel to explore the best ways of providing appropriate training and to explore the possibility of regional response capability so that response time can be shortened.

In addition to requiring emergency response and communications plans, other BMPs establish well integrity and pressure testing, casing/cementing requirements, monitoring requirements, blow out prevention, closed loop systems, secondary containment, no-discharge pads, setbacks and site security measures. These BMPs reduce the risk of incidents and releases of pollutants and provide a measure of protection to the community.

2. The security and social costs to our rural communities if drilling occurs must be considered. An influx in population creates demand on police, fire and EMS. These services are paid for by local taxpayers and sometimes the people are volunteers. They are not trained for blow-outs - nor do they know how to handle accidents dealing with gas-well chemicals. "A list" will not help them or me if a blow-out occurs on a dead-end road. And a few days worth of training sponsored by the gas company does not cut it.

The economic study being completed by the Regional Economic Study Institute at Towson University will provide estimates of the number of workers and the number of truck trips that might be expected from shale gas development in western Maryland. This will provide a way to estimate the magnitude of any impact. The Maryland Department of the Environment's Director of Emergency Management has spoken with his counterparts in Pennsylvania and is sharing information with local governments so that they can assess their capabilities and explore ways to cooperate to provide appropriate training and equipment. Information about chemicals brought to the site will be available in advance to emergency response personnel and, as noted above, local emergency response personnel will receive training so that, in the event of an emergency, they can safely remove the injured and secure the area until specially trained personnel can arrive.

3. Rural areas with aging populations such as Allegany and Garrett Counties are challenged to find adequate numbers of emergency responders, as well as providing training and equipment. The cost of this additional responsibility should be borne by the drilling companies.

The Departments anticipate that drilling companies or an industry group will assist with training and will identify whether special personal protective equipment will be required for the work local emergency responders will be expected to do. The Center for Sustainable Shale Development (CSSD) has developed initial performance standards for operators that represent consensus on what is achievable and protective of human health and the environment. One such standard reads “In preparation for any spill or release event, Operators shall prior to commencement of drilling, develop and implement an emergency response plan, ensure local responders have appropriate training in the event of an emergency, and work with the local governing body, in which the well is located, to verify that local responders have appropriate equipment to respond to an emergency at a well.” If special equipment is necessary, the State will work with the local governments to find resources from the operators or other sources.

4. In the event of accidents, spills, or any emergency situation, first responders have a right to know what dangerous materials they are in contact with.

Information about chemicals brought to the site will be available in advance to emergency response personnel. In addition, the Departments are proposing a streamlined way for any physician diagnosing or treating a patient to obtain information about exposures.

5. There is no detailed “best practice” regarding safety planning. The Natural Gas Industry best practice is to clear the area, call 911 and watch it burn.

The UMCES-AL report recommended that gas well permit applicants should be required to develop site-specific emergency response plans, taking into account that the optimum response may differ depending on the season of the year and the topography of the site. The Departments accepted this recommendation.

In situations where there is an immediate risk to human health and safety, the best practice is to evacuate the area and contact emergency personnel. Also, burning or flaring gas is sometimes the best way to manage a gas release in the short term. Burning natural gas releases mainly carbon dioxide and water.

6. The industry, and gas compressors in particular, is vulnerable to terrorist attack.

Aboveground pipelines, including those entering and exiting compressor stations, have been identified as vulnerable to terrorist attack. Damage to the pipeline could cause a fire that burns until the escaping natural gas is consumed. Valves exist along the pipeline to isolate the damaged section and limit the amount of gas that escapes. A break on a major pipeline could also cause damage by disrupting the flow of natural gas to customers.

Considerable attention has been paid to pipeline security in recent years and industry groups have issued guidance to their members. The Transportation Security Administration has established the Pipeline Corporate Security Review (PCSR) Program. Conducted by the Pipeline Security Branch staff, the PCSR Program is an on-site security review with a pipeline company. PCSRs help establish working relationships with key security representatives in the pipeline industry as well as provide PCSR staff with a general understanding of a pipeline operator's security

planning and implementation. Data obtained from PCSRs aid in establishing a baseline against which to evaluate minimum security standards in the pipeline industry and identify coverage gaps. PCSRs help to identify and share smart practices observed throughout the industry.

7. "Spills . . . cleaned up as soon as practicable." Too vague –allowing time for spills to spread and contaminate further.

The quoted section refers to spills that occur on the drill pad, which is lined and surrounded by a berm. There is a low probability that the spill would spread and cause contamination off the pad. "Practicable" is a term often used in laws and regulations. It is used interchangeably with "feasible" and describes an idea or activity that can be brought to fruition or reality without unreasonable demands.

Each spill event is unique and it is not possible to establish a single rule for when cleanup must be completed. Current Maryland regulation COMAR 26.19.01.02 states:

In addition to any other notifications required by law or permit, the permittee shall report to the Natural Resources Police Force 24-hour Communications Section at (410) 974-3181 or (800) 628-9944 immediately, but not later than 2 hours after detection of, any condition such as fires, breaks, leaks, escapes, spills, overflows, or other occurrences that create a safety or pollution hazard. The permittee shall remain available until clearance to leave is given by the appropriate officials designated by the Department.

We are not proposing to repeal the spill notification regulation. This will act as an additional check on prompt cleanup.

8. The BMPs should require that drilling operations report chemical releases to the federal Toxic Release Inventory, or to a publicly accessible on-line database managed by the state.

The oil and gas industry is not among the industries required to file Toxic Release Inventories under the federal Emergency Planning and Community Right-to-Know Act. As noted above, Maryland regulation COMAR 26.19.01.02 requires that leaks and spills be reported. Other laws, federal and state, require the reporting of oil spills and spills of hazardous materials.

9. There should be a sharing and coordination of emergency management drills by the Maryland environmental agencies with their counterparts in Pennsylvania and West Virginia.

As noted above, emergency response personnel at MDE have initiated discussions with county personnel to explore the possibility of regional response capability so that response time can be shortened and resources shared. Some coordination already exists, and was evident in the response to the overturned propane tank truck in Oakland in April 2014.

ENFORCEMENT AND INSPECTIONS

Consequences, penalties, fines.

1. The BMPs do not mention fines or punishments when regulations are broken and local citizens incur damages.

Current regulations, COMAR 26.19.01.15 provide that the Department of the Environment may, in the event of a violation, issue an administrative order requiring necessary corrective action, including stopwork, or restoration to be taken within the time prescribed. These regulations also authorize the Department to revoke a permit, after notice and an opportunity to request a hearing, if the Department determines that:

- (1) The permittee has failed to comply with the requirements of an administrative order;*
- (2) False or inaccurate information was contained in the application for the permit;*
- (3) Conditions or requirements of the permit have been or are about to be violated;*
- (4) Substantial deviation from plans, specifications, or requirements has occurred;*
- (5) The permittee has failed to allow an authorized representative of the Department upon presentation of proper credentials to:*
 - (a) Enter at any reasonable time upon the permittee's premises where pertinent operations are conducted, or where records are required to be kept under terms and conditions of the permit;*
 - (b) Have access to and copy any records required to be kept under terms and conditions of the permit;*
 - (c) Inspect facilities to ensure compliance with the conditions of the permit;*
 - (d) Inspect any monitoring equipment or method required in the permit; or*
- (6) A change in conditions exists that requires temporary or permanent modification or elimination of the permitted operation.*

Existing State laws and regulations do not provide any administrative or civil penalties for violations of the regulations or permits. These enforcement options are valuable and MDE will consider asking the legislature to provide them.

Under Section 14-118 of the Environment Article, the Department can ask the circuit court of the county where the well is located to issue an injunction to enforce compliance or restrain the violation of any law or regulation in the oil and gas subtitle.

Section 14-120 of the Environment Article provides that any person who willfully violates any provision of subtitle 14 is guilty of a misdemeanor and upon conviction in a court of competent jurisdiction is subject to a fine of: (1) Up to \$ 50,000; and (2) An amount sufficient to cover the cost of damages resulting from all of the following caused by the permittee, including a contractor of the permittee: (i) Any oil or gas spill; (ii) Any other discharge; and (iii) Any violation of this subtitle; and (3) Costs imposed in the discretion of the court.

In 2012, the legislature passed a law that makes it easier for a person whose water supply has been contaminated to compel the owner or operator of a gas well within 2500 feet to provide an alternative source of water. Section 14-110.1 of the Environment Article. If the contamination is within a year of gas well activity, the company would have to prove that it had not caused the contamination. After a year, or beyond 2500 feet, the person whose water supply has been contaminated would have to prove that the company caused the damage.

2. I think that companies with bad records in other states should be banned from Maryland.

Section 14-108 of the Environment Article directs the Department to deny a permit application if the applicant has not corrected any violations committed by the applicant under any prior permit. Each application must be judged on its own merits.

The Departments also encourage property owners to consider the reputation of a company before signing a lease for mineral rights. There are internet resources available whereby citizens can access independent evaluations of oil and gas company environmental performance and disclosure.

3. The coal strip mining rules in Maryland contain provisions that I think should be included in Marcellus drilling regulations. In particular when there are cases where a person's water source or other property is damaged by gas production, the State should have the authority to compel the offending party to make proper restitution or replacement.

There are provisions in Sections 15-516, 15-524 and 15-608 of the Environment Article that require operators of surface coal mines and deep coal mines to replace the water supply of a property owner if the supply has been contaminated, interrupted or diminished. The Bituminous Coal Open Pit Mining Reclamation Fund and the Deep Mining Fund provide a reserve that can be used for this purpose under certain circumstances; for example, if the bonds have been released and the mine is closed. A similar liability provision was enacted in 2012 and codified as Section 14-110.1 of the Environment Article. This, combined with increased bonding and insurance provisions passed in 2013 and codified as Section 14-111 of the Environment Article, protect those in the community. In 2014, Senator Edwards introduced SB535, a severance tax bill that would have directed money into the Oil and Gas Fund. This Fund can be used for purposes similar to the coal mine funds. The bill did not pass.

4. Any intimidation or bribes on the part of the shale fracking/drilling companies or their subsidiaries will result in a direct cancellation of permits immediately and in the future. In addition, steep fines will be placed on the shale fracking/drilling

company, along with possible incarceration of any and all parties involved in the intimidation or bribe.

Bribery of a public official is a criminal offense. Section 9-201 of the Criminal Law Article. Furthermore, Standards Of Conduct For Executive Branch Employees established by Executive Order (01.01.2007.01) state that “an employee shall not, except as permitted by applicable law or regulation, solicit or accept any gift or other item of monetary value from any person or entity seeking official action from, doing business with, or conducting activities regulated by the employee's agency, or whose interests may be substantially affected by the performance or nonperformance of the employee's duties.” Employees found to violate these provisions are subject to disciplinary action, including termination from state employment.

Permits can be revoked for cause. Current regulations provide that a permit may be revoked after notice to the permittee, if the Department determines that:

- (1) The permittee has failed to comply with the requirements of an administrative order;*
- (2) False or inaccurate information was contained in the application for the permit;*
- (3) Conditions or requirements of the permit have been or are about to be violated;*
- (4) Substantial deviation from plans, specifications, or requirements has occurred;*
- (5) The permittee has failed to allow an authorized representative of the Department upon presentation of proper credentials to:
 - (a) Enter at any reasonable time upon the permittee's premises where pertinent operations are conducted, or where records are required to be kept under terms and conditions of the permit;*
 - (b) Have access to and copy any records required to be kept under terms and conditions of the permit;*
 - (c) Inspect facilities to ensure compliance with the conditions of the permit;*
 - (d) Inspect any monitoring equipment or method required in the permit; or**
- (6) A change in conditions exists that requires temporary or permanent modification or elimination of the permitted operation.*

Processes must be open and unbiased.

1. All companies performing any monitoring or assessment should be approved by the State to ensure that no conflict of interest exists which could call into question the accuracy of the results.

The Department of the Environment does not “approve” environmental, engineering or consulting firms that do business in the State. However, any monitoring plans required as a permit condition are subject to departmental approval. These plans

address quality assurance of the data. The Department reviews monitoring and assessment data submitted. Finally, Departmental staff must be provided access to permitted sites at any time for appropriate inspections to ensure permit requirements are being properly implemented. Any data or information indicating violation of permit limits or conditions may be grounds for enforcement action.

2. The applicant should not be allowed to do its own baseline monitoring. Either the State should do the monitoring (using permit fees) itself or the company should be required to use an independent entity, chosen or accredited by the State, and subject to oversight similar to the way the Food and Drug Administration monitors foods and drugs to ensure the reliability of the testing results.

It would not be an efficient use of State resources for the Department of the Environment to perform the baseline monitoring without compensation from the applicant or funding provided by permit fees. In some cases, it would not be practical to use State personnel to perform monitoring, even if funding were available. For surface water monitoring, however, which involves detailed technical procedures for biological assessment, the Department of Natural Resources would prefer to provide the monitoring services. Using DNR monitoring services will reduce the need for costly quality assurance and control review at the State's expense and will likely require fewer resources compared to using a private consulting firm. As noted above, the Department of the Environment does not accredit companies that operate in Maryland or require applicants to use a specific company. However, DNR states a preference for using companies that have been certified for Maryland Biological Stream Survey (MBSS) monitoring techniques. The work plan for baseline monitoring will be approved by the State in advance and the data submitted will be reviewed and checked for quality assurance and quality control.

3. Landowners should have easy access to information about violations. The design of reports and records are important and can help streamline enforcement activities. Digital records help share information with the many stakeholders involved in this process.

The Department of the Environment issues annual enforcement and compliance reports that cover enforcement activities for each of MDE's regulatory programs. MDE also issues regular press releases regarding the most recent enforcement actions by Administration. These items are available on MDE's Web site at <http://mde.maryland.gov/aboutmde/DepartmentalReports/Pages/aboutmde/enfcomp.aspx>.

4. Each well site will have one or more continuous air monitoring systems in operation either in real time or at reasonably short intervals during the lifetime of the operation of the well. The monitors must be able to trigger alarms at the well site and at a remote monitoring site that is staffed 24/7 when established pollutant levels are exceeded. Ideally all toxic chemicals used in the drilling and any expected to be in effluents from the wells should be monitored as well as fugitive methane. After eventual capping of the well periodic monitoring at the site should continue to be conducted.

The Department of Environment investigated the question of ambient air monitoring at well sites. Ambient air monitoring is not justified on a continuous basis for every well, nor would it be practical. The Department is considering monitoring and leak detection and will include appropriate requirements in individual permits.

5. I suggest Maryland require 24 hour video surveillance of all well pads to allow remote monitoring and inspection and provide verifiable data in the event of incidents. This is especially important if Maryland adopts its recommendation that specially trained and equipped personnel must be capable of arriving at the site within 24 hours of the incident.

Even if video surveillance were required, practical constraints would mean that the video would not be reviewed unless an incident was reported. Accordingly, the Departments agree that an important best management practice is the requirement that drilling companies establish emergency response plans to include a mechanism for notifying local jurisdictions promptly regarding chemical spills or releases. During drilling and hydraulic fracturing, the operations are staffed 24/7 by the permittee. Incidents that occur during these times, and times when workers are on site to work on the well or perform maintenance, will be immediately known. Incidents at wells that are operating but unattended can often be detected by the company's own remote monitoring systems. The written communications plan that applicants for permits are required to develop will assure that the information is promptly communicated to the proper authorities. The type of incident that requires specially trained and equipped personnel, such as a well blowout or fire, would probably be immediately evident. Local residents are also encouraged to notify local authorities or the Department of the Environment if spills or other emergencies are witnessed.

6. There should be a clear mechanism for citizens to report violations of the law or of permits or lodge complaints.

The Departments agree that there should be a simple way for citizens to report suspected violations of the law or permits. MDE staff are always on call during the regular workweek and on weekends, holidays and after normal working hours, to ensure that all environmental emergencies are promptly addressed. You may report any environmental emergency that poses an immediate threat to the public health or the well-being of the environment such as oil and chemical spills or accidents causing releases of pollutants by calling toll free (866) 633-4686. Anonymous calls are accepted.

Non-emergency environmental concerns should be directed to the relevant program at MDE. The oil and gas program can be contacted during business hours at 866-MDE GOTO which is (866) 633-4686.

Permittees will be required to post contact information at the entrance to the site. Complaints that are not about violations should be communicated to the permittee.

7. The protocols for monitoring, recordkeeping and reporting should be submitted for public comment. It should be clear about testing of water wells – who will test, what they will test for, and how the tests should be conducted.

The Department of the Environment will provide guidance for monitoring, recordkeeping and reporting. Some will be in regulation, which will be subject to public notice and comment. The monitoring plans themselves will be submitted with the permit application and will be available for public review and comment.

8. There should be a sharing and coordination of environmental monitoring data by the Maryland environmental agencies with their counterparts in Pennsylvania and West Virginia.

The Department of the Environment participates in interstate compacts and attends regional meetings where information is shared. The Department also maintains communication with regulatory agencies in other states through conferences organized by the National Governors Association, the Environmental Council of the States, and EPA. Furthermore, in developing Maryland's draft best management practices and other related recommendations and requirements, the Departments have reviewed incident and other environmental data in neighboring states and throughout the country to ensure the best practices for environmental protection are adopted.

State resources may be inadequate.

1. Conducting inspection and enforcement activities is challenging due to limited information, such as data on groundwater quality prior to drilling. Hiring and retaining staff and educating the public are challenges. I have great concern about the availability of qualified individuals to perform these functions.

Site-specific background data will be collected for each site. The Departments are aware of the challenges of hiring and retaining qualified personnel. The Department of the Environment's future adoption of permit fees will help with hiring additional personnel to assist with inspections and enforcement.

2. Money for state inspectors and independent inspectors should come from higher permit fees, not tax payer dollars. In the strongest possible way, I want to emphasize that the resources to pay for regulators, monitors and enforcers of such vital functions as water quality, air quality and noise monitoring should be borne by the drilling companies.

The Department of the Environment is authorized to set application and permit fees for oil and gas wells at a level to operate the regulatory program, including monitoring and enforcement.

New programs are needed.

1. A new regulatory agency is necessary.
 - a. A "designated agency" would be set up and maintained through the county or state government for permit issuance, reporting purposes, inspections, and legal action. All of which would be considered a reimbursable fee to the shale fracking/drilling companies reimbursed on a monthly basis.
 - b. Any illnesses resulting from the shale fracking/drilling companies for families, and employees of the shale fracking/drilling company, must

be reported to the “designated agency.” All information regarding hazards, illnesses, contamination, road spills, etc. will be a part of public record and maintained by the “designated agency”.

- c. Inspectors are to be hired by our county or state government, though the “designated agency” and the funds to pay for their salaries and benefits are to be reimbursed by the shale fracking/drilling companies on a monthly basis through an invoice provided by the “designated agency.” This also includes any fees incurred, such as mileage, maintaining an office, etc. The shale fracking/drilling companies may not be or hire their own inspectors to report to the permitting “designated agency”.
- d. All chemicals that are to be used must be submitted to the “designated agency” prior to permit issuance. These chemicals cannot include contaminants that would affect any aquifers, rivers, wells, or public drinking water or cause cancers or illnesses. All of these chemicals will be a matter of public record. Inspectors will test the chemicals on a bi-monthly basis to ensure hazardous chemicals are not being used by the shale fracking/drilling companies.
- e. All clean-up will be provided by the fracking/gas drilling company within 3 months of vacating any site. In addition, the shale fracking/drilling company will be held completely responsible for expenses relating to the clean-up and maintenance of any capped well that may later leak after being closed, as well as any other issues resulting from this leak. There will be no time limit on this maintenance. A designated trust fund is to be set aside to cover these expenses and is to be used only for the purpose of maintaining closed wells. This amount will be provided by the “designated agency.”

Many of the tasks the commenter wishes to assign to a new designated agency are already within the responsibility of existing state agencies. Likewise, permit fees will be established and paid by industry to help support regulatory oversight activities. The substantive concerns expressed by the commenter regarding chemicals and clean-up are addressed in Departmental responses to chemicals and emergency response-related comments.

- 2. There should be clearly identified state agency points-of contacts, processes, open damage claim reporting and detailed restitution when issues arise. There should be a mechanism to fairly compensate people for economic loss and personal harm, especially people who did not lease their mineral rights but are impacted by gas development nearby. The State should consider denying a CGDP permit if any landowner within the CGDP does not own his mineral rights (i.e. a split estate).

The commenter may be envisioning something like the court-supervised settlement program that was instituted after the Deep Water Horizon well blowout in the Gulf of Mexico. The settlement followed two class action lawsuits and set up a procedure and fund to compensate people for economic and property damage claims and

medical claims. Such programs are not developed in advance, on the chance that an incident will occur.

The court system provides an avenue for individuals to seek compensation for injury or damage caused by willful misconduct, negligence, trespass, nuisance and contamination. The Department of the Environment can order a permittee to cease a violation and remediate spills, but there are issues of due process, property rights and contract rights that preclude a State agency from circumventing the legal process and awarding damages.

3. We want the State to secure and fund an external independent environmental consulting and auditing entity or capability (firm) to perform daily independent inspection of all on-the-ground drilling activities to ensure full compliance of all regulations. This firm will host bi-monthly or monthly public meetings to address current concerns and complaints with local stakeholders. Oversight of this firm will be provided by a small Board of Directors composed of local civic leaders. And lastly, that "drilling fees" be established by MDE with a line-item breakdown of drilling fees and what they include so that it is possible to ensure that adequate funds for inspection and enforcement is possible.

This firm will fill the following roles:

1. insure that the enforcement and inspection function is adequately funded, well managed and staffed with qualified personnel;
2. promote transparency via bi-monthly or monthly public meetings to address issues in a timely manner;
3. protect the enforcement and inspection function from political and energy sector intimidation or influence;
4. perform ongoing auditing and reporting functions to track the effectiveness of regulatory enforcement practices; and provide an external source of objective expertise relating to drilling practices.

See response to comment 1 "A new regulatory agency is necessary". The Department of the Environment has the authority to assess application and permit fees for oil and gas wells in amounts sufficient to fully fund its program, including inspection and enforcement. The Departments take their missions very seriously and are guided by science. Intimidation is not an issue. MDE prepares an annual enforcement report on all its programs.

4. There is a strong need for a Comprehensive Gas Drilling Inspection Program (CGDIP) that would:
 1. Require special training for inspectors in Maryland to follow for inspection compliance,
 2. Show all phases of development and the inspections for each phase,
 3. Allow for random visits and spot inspections
 4. Mandate compliance with each phase for work to continue,

5. Establish a community/citizen watch program, that would train individuals on how to report incidents and/or violations,
6. Establish a Natural Gas hot line for reporting,
7. Mandate the number of inspectors in relationship to the number of permits,
8. Establish a sliding scale penalty for repeat violations,
9. Establish a three strikes and out program that would keep repeat violators from receiving permits,
10. Establish an Ombudsman commission for review of complaints and compliance issues,
11. Establish a website for licensure, permitting and inspection, which would include public notification of CGDP planning and permitting. This site could also be used for the CGDP Toolbox,
12. Establish a field office of the Natural Gas division of MDE/DNR in Garrett County.

If inspectors need additional training, MDE will secure that training and recover the cost through application and permit fees. If the intensity of gas development justifies it, MDE will locate trained inspectors in a western Maryland office. Unannounced inspections are already a part of MDE's inspection process. There is an existing method by which citizens can report incidents and suspected violations. An individual may report any environmental emergency that poses an immediate threat to the public health or the well-being of the environment such as oil and chemical spills or accidents causing releases of pollutants by calling toll free (866) 633-4686. Anonymous calls are accepted. Non-emergency environmental concerns should be directed to the relevant program at MDE. The oil and gas program can be contacted during business hours at 866-MDE-GOTO, which is (866) 633-4686. On-site inspections by citizens are inadvisable due to security and safety concerns, as well as issues of trespass.

The Departments are committed to openness and transparency and will make efforts to provide all necessary information on its website. Compliance issues should be handled through the MDE's established inspection and enforcement program. The idea of an ombudsman has merit and could be considered if companies are not responsive to citizen concerns.

Existing State laws and regulations do not provide any administrative or civil penalties for violations of the regulations or permits. These enforcement options are valuable and the Department of the Environment will consider asking the legislature to provide them. Appropriate penalty amounts for second and subsequent violations could be incorporated.

A "three strikes" rule is not appropriate because the types of violations range from minor to serious. Each application will be considered on its merits.

5. The collection of pre-development baseline data is good, but the same kind of data should be required during the production and for at least 3 to 5 decades after decommissioning and capping.

Periodic monitoring will be required while the well is in production, but at this time the Departments are unaware of any justification for monitoring for decades after the well has been properly abandoned and the site reclaimed. Post-closure requirements can be reevaluated and adjusted if there is a reason to require additional monitoring.

6. All storage containers and transportation vehicles that handle wastewater, flowback, drilling muds, cuttings, fuel and chemicals should have GPS tracking, placards and radioactive monitors.

The draft best practices report recommended that applicants submit a transportation plan and a waste management plan for approval. In order to assure that all wastes and wastewater are properly treated or disposed of, the Departments proposed to require permittees 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. In the draft report, the Departments proposed to “Require that all trucks, tankers and dump trucks transporting liquid or solid wastes be fitted with GPS tracking systems to help adjust transportation plans and identify responsible parties in the case of accidents/spills.” There was wide support for the GPS requirement, but the Maryland Motor Truck Association commented that this requirement “is virtually impossible in an industry that is deregulated, highly fragmented, and uses a large number of independent contractors to meet short-term transportation needs.” The permittees and operators are in a position to require its contractors and subcontractors to use GPS equipment, despite the fragmentation of the industry.

The transportation of hazardous materials is regulated by the United States Department of Transportation, which requires placards for shipments of hazardous chemicals above threshold amounts. For example, a truck would have to display a corrosive placard if it carried a material that met the definition: “a liquid or solid that causes full thickness destruction of human skin at the site of contact within a specified period of time. A liquid, or a solid which may become liquid during transportation, that has a severe corrosion rate on steel or aluminum based on the criteria in §173.137(c)(2) is also a corrosive material....” 49 CFR 173.136(a).

Lastly, the Departments proposed that cuttings, flowback, 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.

7. While there is Federal regulation of new construction of pipelines with the attendant compressor stations, no State agency exists to oversee the siting, construction and operation of these assets.

The Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation has established standards for the material, design, construction, and testing of pipelines that carry natural gas. The Federal Energy Regulatory Commission (FERC) authorizes interstate pipelines, including

compressor stations that are part of interstate pipelines. Intrastate pipelines, including compressor stations that are part of intrastate pipelines, are overseen by the Maryland Public Service Commission (PSC). FERC approves the siting of proposed routes for interstate pipelines and associated facilities. Intrastate lines do not have to come to the FERC or the PSC for approval of their routes. Their routes are developed through agreements with landowners for the right-of-way. They do have to get approval from other State agencies for such things as air permits and stream crossing permits. The PSC has the authority to inspect gathering lines and intrastate pipelines.

The Comprehensive Gas Development Plan will help coordinate the siting of drill pads, gathering lines, compressors, and other ancillary facilities.

8. Currently, federal oversight of pipelines in Maryland is inadequate. To expand the number of pipelines by authorizing increased production via well permitting while the regulatory system is already struggling under current conditions would only increase the likelihood of accidents or failures.

The safety of interstate gathering lines, transmission lines, compressor stations and storage facilities is regulated by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). The Maryland Public Service Commission (PSC) regulates these facilities when they are classified as intrastate, and the PSC also regulates distribution systems. If drilling is permitted, there will certainly be more intrastate pipeline development. The capacity to manage these additional needs will be expanded if required.

9. Post-operational sampling of air quality should be required for ancillary facilities, such as compressor stations, that have the potential to emit gases.

The Departments will require monitoring of ancillary facilities such as compressor stations in air permits, if justified.

Financial liability for monitoring and harm.

1. Companies permitted to conduct a fracking operation in Maryland should be required to post a bond sufficient to cover penalties for any violations that might occur in the course of their work, regardless of any showing of negligence on their part. These penalties need to be sufficient to cover the costs of restoring the environment to a safe and livable condition.

Financial assurance and bonding requirements in Section 14-111 of the Environment Article address these concerns.

2. All legal fees acquired by a landowner, affected party, or the government will be reimbursed by the shale fracking/drilling companies for any reason.

The general rule in America is that each party to a suit pays its own attorney's fees. Court costs are usually paid by the losing party.

3. There should be adequate bonding and insurance requirements, lasting beyond the closure of the well. Bonds for delayed contamination caused by triggering hydro-geo-mechanical events should be added, such as the inevitable upward migration of enhanced vertical permeability.

The Departments do not agree that contamination is likely to be caused by upward migration due to hydraulic fracturing. Bonds are released only after closure is complete. Environmental Impairment Liability insurance must be secured and maintained for 5 years after the Department determines that: (1) The gas or oil well has been properly sealed and plugged; and (2) The site has been reclaimed.

4. Demand that companies engaged in fracking are financially liable for any and all costs incurred by residents including health expenses, soil contamination, legal fees, loss of property values and reduced quality of life during and after the operation.

Financial assurance and insurance will guarantee that funds will be available if the companies engaged in hydraulic fracturing are liable for damages.

5. Any and all hazards, such as well contamination, explosions, death, crop destruction/contamination, hazardous fuel transportation accidents, business loss, etc. that are directly associated with fracking/drilling will be paid for by the company. This includes, but is not limited to emergency personnel costs, funeral costs, loss of income, land devaluation, legal fees, injuries, and any costs associated with the hazard.

See responses to comments 1-4.

6. There should be an explanation of what the State would do, or compel the company to do, if gas were to flow from somewhere in the gas field into a person's home or into the atmosphere. What are the requirements for restoration of trout streams should fluids pollute the water? What types of restitution should citizens expect if their property and or health is negatively impacted, or are locals expected to work with the oil & gas firm directly? A process must be developed to deal with and assign responsibility for unexpected problems especially if more than one industry operator is working in the same area.

Current regulation COMAR 26.19.01.15 provides that the Department of the Environment may, in the event of a violation, issue an administrative order requiring necessary corrective action, including restoration, to be taken within the time prescribed. The specific instance of contamination of drinking water within 2500 feet is addressed in Section 14-110.1 of the Environment Article. There are existing liability and pollution insurance requirements in §14-111 of the Environment Article. Also a bill introduced by Senator Edwards in the 2014 session, SB 535, would provide funds and authorize the Department to take corrective action if the persons responsible for the harm could not be identified or were bankrupt or otherwise judgment proof. This legislation did not pass.

7. We believe that liability of water well contamination within 2500 feet of a drilled gas well must be incorporated into the permitting process and the time period extended beyond one year of the drilling activity to ensure water quality and public health are protected.

Persons with drinking water wells within 2500 feet from the gas well or whose wells are contaminated within a year after the last event of well drilling, completion, or hydraulic fracturing can take advantage of the presumption established in Section 14-

110.1 of the Environment Article. After one year, the person whose drinking water was affected would have the burden of proving that the gas company was liable. If gas activity is permitted, monitoring results or new research might justify extending the time period for this presumption.

ENGINEERING, DESIGN AND ENVIRONMENTAL CONTROLS AND STANDARDS

Ponds.

1. Ponds should be used only to collect or store fresh water; all other material shall be stored in tanks.
2. We support the proposed prohibition on open impoundments for the storage of flowback and produced waters as a necessary safeguard. Open impoundments create unnecessary risks of wildlife exposure to chemical-laden fluids and environmental damages from impoundment spills. MDE and MDNR have laid out an appropriate approach, allowing open impoundments to be used only for fresh water storage.
3. The state needs to coordinate closely with the local municipalities on construction standards for ponds.

The Departments agree that ponds should be used for fresh water only, and that flowback and produced water should be stored in tanks while on-site. This was a recommendation in the draft report. The regulations will also specify that the tank system has sufficient structural integrity and is appropriate for the storing of the intended wastes, including compatibility with the wastes.

Ponds must conform to USDA Natural Resources Conservation Service Maryland Conservation Practice Standard Pond Code 378 (January 2000). The standard establishes the minimum acceptable quality for the design and construction of most ponds.

Casing, cement, and centralizers.

1. The use of reconditioned casing should not be permitted.

The Departments do not agree. It is appropriate to use reconditioned casing if it meets API performance standards for compression, tension, collapse and burst resistance, as well as quality and consistency.

2. The specified safety margin of 1.2 for reconditioned casing seems small; a factor of 2.0 is viewed as more common.

The draft report recommended that 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 proposed recommendation is based upon API Standard 5CT, Specification for Casing and Tubing, and the Departments consider it appropriate.

3. How did the Departments determine that pilots can be “safely cased through” coal mines?

The Departments recognize the inherent danger in drilling through coal mine areas. A pilot hole would be a small diameter hole drilled to provide more site-specific knowledge of the subsurface geology. Coal seams would only be present in the first several hundred feet from surface and the pilot could provide valuable information for the development of the actual casing and cementing plan for a production well. The pilot would be similar to a coring that is presently done to define geology in preparation for a coal mine permit. The judgment that holes can be safely cased is based on experience. In comments, the Board of Directors and committee members of the Casselman Coal Poolee Association endorsed this recommendation.

4. Requiring the cement to remain in a static state for a minimum of 12 hours and to achieve a compressive strength of 500 psi is excessive. Modern cement additives and slurry designs can achieve the 500 psi requirement in much less time than 12 hours. It is recommended the recommendation be changed to allow for continuation of activities if the cement has reached a minimum of 500 psi.

The Departments recognize that the 12 hour set time will cause some delay in drilling. The Departments also believe that the proper setting of the cement is one of the most critical tasks in the safe drilling process. The Departments therefore do not accept the suggested change.

5. For cementing, centralization, and wellbore isolation, it is suggested the recommendation incorporate API Standard 65-2, "Isolating Potential Flow Zones During Construction" in the document. This standard contains design and engineering practices for isolation of potential flow zones and goes beyond the limited recommendations found in the current document. API Standard 65-2 has been adopted into both federal and state regulations and serves as an industry guidance document for proper well design and construction.

API Standard 65-2 would qualify as a "relevant API standard." The best practice report requires that the applicant for a well permit file a plan that follows the normative elements of relevant API standards, or demonstrate that an alternative is at least as protective.

6. The recommendation is all coupling threads meet the API specifications and casing strings be assembled to the correct torque. This requirement eliminates proprietary threads that may exceed API specifications and also does not allow for the use of couplings that are made up to a particular depth rather than a minimum torque. The recommendation should allow for the use of API threads or threads that exceed API requirements based on an engineering analysis and judgment.

The Departments agree and will amend the recommendation to provide that the applicant can, when submitting the plan for a well, make an engineering demonstration that an alternative is at least equally protective.

7. There is a recommendation that the operators "must use a sufficient number of centralizers to properly center the casing in each borehole." There is no definition of what degree of centralization is required, the allowable type of centralizers, or the proposed installation methods. This information can be found in the API

technical documents, recommended practices, and specifications for centralizers. It is recommended the recommendation include these documents by reference.

API Standard RP 10D2 regarding use of centralizers would qualify as a “relevant API standard.” The best practice report requires that the applicant file a plan that follows the normative elements of relevant API standards, or demonstrate that an alternative is at least as protective.

8. The State and the MSAC needs to do more to study and address the causes of casing integrity failure and to propose better practices that continually improve performance of casing integrity.

The Department of the Environment actively participates in forums and follows studies conducted by agencies and organizations such as EPA, the Groundwater Protection Council, the National Governors Council and the Interstate Oil and Gas Compact Commission. The Departments are also requiring rigorous monitoring before and during well development to assist in identifying casing/cementing problems. In addition we will continue to monitor other states and industry developments.

Additives, closed loop systems for drilling mud and cuttings.

1. Our organization supports the Report’s recommendation in Section VI part H that “Diesel fuel shall not be used in hydraulic fracturing fluids.”

The use of diesel fuel in hydraulic fracturing has been the subject of concern in several contamination investigations. The Departments do not propose to allow its use in hydraulic fracturing in Maryland.

2. Closed loop mud systems are commonly used where non-aqueous drilling fluids are used. There may be unintended consequences of requiring closed loop mud systems for all drill sites. A closed loop system will add costs to the drilling operation and will require additional space on the drilling pad to incorporate the technology. To allow for spotting the needed tanks for the process can require up to 6 acres for the drill site. This increases the surface footprint of the drilling pad above what would be required for non-closed loop systems.

The Departments believe that the benefits of the closed loop system in managing and disposal of cuttings and waste drilling fluids exceed the temporary impact of land disturbance for the tanks and structures needed. The Departments note that at least a portion of that disturbance will be offset by not constructing pits for storage.

3. How will the Department determine whether to approve additives for drilling fluids?

As mentioned in the draft report, only additives suitable for drilling through potable water can be used for at least 100 ft below fresh water or coal seams. For drilling below that depth the Department of the Environment will consider the constituents of the product, the concentrations to be used, and information on toxicity and health effects from the Material Safety Data Sheets.

Pad construction and containment.

1. “Permeability” is the wrong word in the sentence: “Drill pads must be underlain with a synthetic liner with a maximum permeability of 10^{-7} centimeters per second ...”

The commenter is correct; “permeability” will be replaced by “hydraulic conductivity.”

2. Containment around tanks and containers should be underlain with a synthetic liner with a maximum permeability of 10^{-7} centimeters per second to prevent leaching into the soil.

The Departments anticipate that many tanks and containers will be located on the pad, where the liner must have a maximum hydraulic conductivity of 10^{-7} . Secondary containment is required for all stored chemicals and wastewater, but this low hydraulic conductivity may not be necessary in all circumstances. The Spill Prevention Control and Countermeasures Plan must address the prevention and clean up of spills.

3. The berm should be made impermeable with the use of the liner. In the event of a high volume, high pressure liquid release an earthen dam will likely fail and use of a liner would prevent or minimize a failure.

The best practices report recommended that the drill pad must be surrounded by an impermeable berm. This may be accomplished by using natural materials or a liner. The applicant must submit a plan for constructing the pad and containment structures with the application for a well permit.

Integrity testing and BOP.

1. Use of data obtained through open hole logging to “fine tune” processes and information (as recommended by UMCES-AL) should not be considered sufficient stand-alone information in the absence of a complete study of hydrology of the site. We should not be drilling blind in Maryland and using the drilling process to document the strata.

The UMCES-AL report stated, in the context of discussing different well logging techniques, that “The best practice would utilize modern open-hole well logging methods to help fine tune casing placement and characterize flow and hydrocarbon zones, perhaps mud logging to determine levels of hydrocarbons in real-time during drilling, and SRCBL, casing collar logging, and gamma logging as part of a cased-hole program.” The use of open hole logging is intended to supplement data already available and to be used in the permit review process. Any site specific data will be valuable to subsequent well placement and technique. All available hydrologic data such as existing water or other wells, previous excavations and all geologic/seismic data will be evaluated in the individual permit process.

2. Due to concerns about casing integrity discussed above, the plan for integrity and pressure testing submitted by applicants for individual well permits should include integrity tests not only at drilling and re-fracturing, but also at annual intervals until the well is plugged, and at regular intervals going forward.

The Departments agree that testing should be performed periodically during the lifetime of the well. The specific types of tests and frequency of tests will be an issue addressed in each permit and based upon the documented pressures at each individual well. The Departments are not aware of justification for integrity testing after the well is plugged.

3. Rather than specifying that blow out preventers should be tested at a pressure in excess of that which may be expected at the production casing point before drilling the plug on the surface casing; and penetrating the target formation, the regulations needs to specify that blow out preventers the pressure to be 1.2 times the pressure during stimulation, which is the highest pressure normally experienced during the life of the blowout preventer.

The regulations will be clarified to provide that the 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. The regulation will likely closely conform to API RP 53.

4. The regulations recommend pressure testing of Marcellus shale gas wells. That isn't sufficient. The BMP practice recommended in the UMCES report to require pressure testing should instead be adopted. Doing so would greatly increase the likelihood that all wells would function as they should.

See response to question 2 above regarding increased frequency of integrity/pressure testing. Moreover, in the draft best practices report, the Departments wrote: "The UMCES-AL report recommended Maryland should consider amending its regulations to require SRCBL (or equivalent casing integrity testing) and other types of logging (i.e., neutron logging) as part of a cased-hole program. The Departments agree and propose to require SRCBL." In addition, the Departments will require mechanical integrity tests to be performed when re-fracturing an existing well.

Noise, light and hours of operation.

1. The best practices report notes that if drill pads are located within 1,000 feet of aquatic habitat, screens or restrictions on the hours of operation may be required to further reduce light pollution. Additional light sensitive uses include residential units, educational facilities, hospitals, critical facilities and agricultural uses including livestock. Maryland should consider developing light standards for pre and post curfew time periods when sensitive land uses are near-by.

The Departments agree that there are many sensitive land uses that could be affected by drill pad lighting. These issues will be considered in the CGDP and addressed on a case-by-case basis during the individual well permitting and associated public participation process, taking into account the nearby sensitive land uses and stakeholder concerns.

2. The report says that restrictions on hours of operation can only be applied to activities that could be planned in advance or temporarily suspended. This statement gives the industry an escape clause to use lighting at any time during development activities. It should be strengthened to say, in the last sentence: For

this reason, activities should be planned in advance so that all measures can be in place to protect surrounding communities from light pollution.

Advance planning and the selection of proper lighting can minimize the effect of lighting, but lighting is a safety issue.

3. Light pollution as well as noise pollution should be addressed because light pollution corrupts the wildlife cycles and destroys the sense of solitude for residents and tourists.

The Departments agree and this is why both light and noise pollution will be considered at multiple stages of the gas well development process, from the CDGP process all the way through issuance of individual permits.

4. Ban flaring during hours of darkness, and also ban lighting that destroys the night sky.

The Departments have proposed restrictions on flaring and lighting that protect the public and do not compromise the safety of workers. The Departments propose that night lighting be used only when necessary, directed downward, and that low pressure sodium light sources be used wherever possible.

5. The recommendation that drilling should avoid times of peak outdoor recreational periods is unreasonably restrictive.

This recommendation is not only for aesthetic purposes but also to ensure public safety. Consideration will be given in individual well permits to the proximity of the well to peak recreational uses.

6. The recommendation about lighting should state that nothing in this section should be construed to compromise safety of operation at the drilling site.

Safety at the drill site is essential to prevent harm to workers, the environment and public health. The manner in which lighting is addressed at each well pad will not compromise safety of operations.

Standards and updating standards.

1. There is a long list of plans and information that must be submitted with an application for a drilling permit. Will regulations provide “standards” for most of these, or are the approval criteria viewed as inherently case-by-case?

Before a permit will be issued, the applicants are first required to develop a Comprehensive Gas Development Plan, and guidance is provided in the Best Practices document to inform that effort. Plans for individual wells must then conform to the Engineering, Design and Environmental Controls and Standards. Relevant API standards must be considered and, if the applicant fails to incorporate a normative element of a relevant API standard, the plan must explain why and demonstrate that the plan is at least as protective as the normative element. All applications will then be reviewed individually and additional site-specific conditions may be considered at that time. Regulations will provide guidance as to what will be expected in the application.

2. Given the view that mandating particular technology is neither appropriate nor necessarily productive, the question becomes how the adoption of “better” as well as more efficient technologies might be motivated. An option for consideration: require industry to discuss their plan for adoption of “better” technology as part of the CGDP’s and/or the individual well applications.

One way the Departments will encourage the adoption of better technology is to require consideration of all relevant API standards. These standards are periodically updated. To the extent better technologies are developed, they can and should be considered both in the CGDP and the individual permit.

3. Maryland should adopt the Center for Sustainable Shale Development performance standards as a baseline. Deviations from those standards, if any, should be limited to those necessary to reflect conditions that are unique to Maryland.

The Departments incorporated some of these performance standards into their best practices report and agree that the standards can be a useful tool for evaluating whether plans submitted with applications for individual permits are adequate. The Departments do not think it necessary to adopt those standards as a baseline. If these standards meet or exceed normative API standards, however, they can be used by applicants in place of API standards and will be approved by MDE, provided they meet other applicable regulatory requirements.

Fuels and engines.

1. Engines operating on a site for less than 12 months are federally-defined as nonroad mobile engines, and Maryland is pre-empted by the Clean Air Act from imposing any emission standards on those engines.

This is correct. Maryland is preempted from making these federal regulations applicable to a class of engines that are excluded from the federal regulations. The recommended best practices will be changed to avoid imposing emission standards on those engines; however, the State will continue to explore ways to reduce emissions from nonroad mobile engines.

2. The final report should not mandate the use of electrical powered equipment or designate a preferred fuel source for engine-powered equipment.

The Departments are not mandating the use of grid-based electrical power or a fuel source for equipment. There are multiple factors which would favor the use of one power source or fuel over another, including the land disturbance necessary to bring power to the site, the greenhouse gas footprint of electricity supplies and the loss of power resulting from running electrical transmission lines to the drill site. The Departments recommend that applicants provide a power plan that results in the lowest practicable impact from the choice of energy source. The recommendation for using natural gas or propane is a preference, not a requirement.

3. All on-highway and nonroad vehicles are already required to use ultralow-sulfur diesel fuel, so Section IV.J.4.a should be removed as unnecessary.

The requirements were fully phased in for most engines by 2014. The provision may be unnecessary, but there does not seem to be any harm in keeping it.

Roads.

1. Given the levels of traffic and the size of equipment used, even gravel roads will need to be planned and engineered to be safe. Additional design standards are needed.
2. Why use Pennsylvania road specification? The State of Maryland has been very critical of natural gas operation in Pennsylvania. It just seems strange that we would rely on their standards, especially since Maryland has been so critical of Pennsylvania's management of Marcellus gas development. Allegany and Garrett County have standard specification and roads department personnel to review and approve plans for roads. Let the two counties determine road requirements as they do for all need development in the counties.

The Departments agree that new roads used by the industry will need to be planned and engineered. The UMCES-AL report recommended using Pennsylvania's "Guidelines for Administering Oil and Gas Activity on State Forest Lands" because they contain particularly good practices for constructing and maintaining gravel roads for Marcellus Shale development in Pennsylvania state forests. Since Pennsylvania already experienced the traffic and associated wear-and-tear on roads that occurs during gas well development, it has valuable experience in developing guidelines on proper road design to protect state forests. Furthermore, since much of the Marcellus underlies Maryland's heavily forested counties, roads designed to protect forested landscapes are most appropriate.

Pennsylvania's guidelines recognize that roads constructed for gas development will experience repeated use over the life-cycle of well production, must be designed to withstand heavy, sustained, industrial scale traffic over decades, must protect forest lands and waterways, and must serve other purposes (utility corridors) in addition to vehicular access. The guidelines also include other important consideration such as guideline for emergency and pollution incidents. The Departments view these guidelines as protective of Maryland's water quality and natural resources.

The standards for roads are meant to apply only to private roads, such as access roads, that may be constructed to reach the well pad. Garrett County has established minimum standards for private roads in its subdivision regulations, but "road" is defined as "a public or private thoroughfare which affords the principal means of access to 3 or more lots or that is an expressway, but not including an alley or a driveway." Under this definition, the standards would not apply to an access road. Allegany County reviews the plans for private roads, but has no construction standards. Both Counties have standards that will apply to the construction of public roads or roads that will be dedicated to public use. Where they apply, these standards and not Pennsylvania guidelines will be used.

Invasive species, site closure.

1. The permit should require photographs of the site before the activity starts. This information will be very helpful for reclamation assessments later on. Because

mines operate for such a long timeframe, very few people remember what the conditions were 30 years ago.

The Departments agree with this comment. Permit requirements for a pre-development site characterization should include photographic records. Site closure requirements after gas extraction has occurred should also include photographic records.

2. All clean-up will be provided by the fracking/gas drilling company within 3 months of vacating any site.

Current laws and regulations place the responsibility for site reclamation on the permittee. Performance is assured through bonding. The time period for when site reclamation must start after gas well drilling is completed and how long it should take to complete the reclamation is not spelled out in the BMP document; however, a reclamation plan must be submitted with the application for a well. This plan and the invasive species plan must address both interim and final reclamation. An approved plan becomes part of the permit and therefore is enforceable.

3. All construction of well-pads and associated uses should be prohibited in areas that are dominated by invasive species.

The Departments agree that construction in areas dominated by invasive species has the potential to spread those species. The invasive species plan set out in the best practices report was intended to address the risk that invasive species would be introduced to the construction area, but it will also serve to prevent the spread of invasive species from the construction area. For example, the applicant must perform an inventory survey of sites prior to operations, and the plan must include 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.

4. Keeping equipment clean is important for controlling the spread of invasive species, but it is also important to monitor construction materials such as any soil, gravel or fill dirt that is brought to the site for construction. If there are existing invasive species, pre-treatment activities should be required before construction starts.

The Departments agree with this comment. The invasive species management plan should emphasize avoidance, early detection and rapid response. The elimination of existing invasive plants should be considered. For species that do little damage, control may not be warranted. For large existing infestations, the level of effort required may be prohibitive and the probability of success very low. However, for relatively small infestations of extremely damaging invasive plant species, control can be both cost-effective and successful. We adopted the UMCES-AL recommendation that topsoil should be stockpiled during site development activities, covered during storage, and used on site during reclamation. The invasive species and reclamation plans must address the risk that materials brought on site may bring invasive species.

5. Annual monitoring for invasive species should occur at the appropriate time of year to identify early infestations. Annual monitoring should occur throughout the entire lease cycle plus one year. Because many plants have seasons, it will be important to have the last inspection in the growing season after activity has stopped.

The Departments agree with this comment. These monitoring activities will be required for each operator's invasive species management plan that must be reviewed and approved by MDE before any permits are issued.

6. In some cases, grading and plantings will be needed to return the site to pre-construction conditions. For example, a formerly forested area might be re-planted with trees. The use of seeds should be expanded to include soil, mulch and plant materials.

The Departments agree. As stated in the best practices report, the goal of reclamation should be to return the developed area to native vegetation (or pre-disturbance vegetation in the case of agricultural land returning to production) and restore the original hydrologic conditions to the maximum extent possible.

Miscellaneous comments on standards.

1. Gathering lines are already adequately regulated. The rural gathering lines from the Accident Dome underground storage wells are under very high pressure when gas is being injected into the wells during warm months and extracted during the winter months. The standards for material and construction adequately address this activity.

The federal Pipeline and Hazardous Materials Safety Administration (PHMSA), has relatively few requirements for gathering lines. It is in the process of collecting new information about gathering pipelines in an effort to better understand the risks they may now pose to people and the environment. If the data indicate a need, PHMSA may establish new safety requirements for large-diameter, high-pressure gas gathering lines in rural locations. Pending this action, the Departments are recommending two simple and commonsense requirements: that the locations of the lines be registered through Miss Utility, and that all pipelines and fittings 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.

2. This is not a difference of opinion, this is basic physics. Gas when released goes straight up. Therefore, gas in a distant fissure far from the bore is not going to make its way into the pipe. It will be released into the air.

The horizontal borehole runs through the target formation thousands of feet below the surface. The pressure is very high at this depth. In normal circumstances, the methane, fracking fluid and water in the formation, like other gases and fluids, tend to flow from an area of higher pressure to lower pressure; that is, to flow from the formation into the wellbore.

FORCED POOLING

1. I have serious concerns about your suggestion of "forced pooling" of properties. Forced pooling is a violation of property rights.
2. Citizens of Maryland should be assured that the State will never force landowners who own their mineral rights to allow extraction of the resources (gas) under their land without their consent.

Forced pooling compels landowners who have not leased their gas rights to allow a driller to extract gas from their land. It is common in oil and gas states, although the specific provisions vary from state to state.

In New York, for example, an applicant for a permit to drill an oil or gas well must include, in the permit application, a map showing the contiguous area from which the well will be able to extract oil or gas. This area is called a spacing unit, and it may include land for which the applicant does not hold mineral rights. If the applicant controls mineral rights to at least 60 percent of the acreage in the proposed spacing unit, the applicant can petition for compulsory integration, as forced pooling is called in New York. There is a hearing process before the state acts on the petition. The landowner has three integration options: as a royalty owner; as a non-participating owner; or as a participating owner. These options have different formulas for sharing risks, costs and revenues in the pooled area

Maryland does not have a law that expressly forces or compels mineral interest owners to pool their resources with those of other mineral interest owners. Maryland does, however, expressly recognize and regulate voluntary pooled units. The Departments are not recommending any statutory change that would allow forced, compulsory, or involuntary pooling. If such a change were to be made, it would require an act of the Maryland legislature.

IMPACTS ON CHESAPEAKE BAY

1. Fracking will make it more difficult to meet the Chesapeake Bay Total Maximum Daily Load (TMDL).
 - a. Fracking and its associated infrastructure, including well pads, pipelines and compressor stations, will result in additional deforestation, increased impervious surfaces, construction run-off, and other land-use degradation that will likely impact the Bay TMDL. Fracking fluid spills or waste would also contaminate the Bay watershed.
 - b. The Department's treatment of stormwater runoff from increased oil and gas development bears particular importance in light of Maryland's efforts to comply with EPA's mandates under the Chesapeake Bay Total Maximum Daily Load (TMDL). First, some of the lands proposed for hydraulic fracturing drain in to the Potomac River that feeds the Chesapeake Bay. Increased industrial development within the Chesapeake Bay watershed will likely have substantial effects on stormwater pollution levels.

While most of the Maryland portion of the exploitable Marcellus Shale lies outside the Chesapeake Bay watershed, the Allegany County portion and part of the Garrett County portion are in the watershed, albeit at a distance, and therefore could theoretically have an adverse impact on the Bay. The Bay TMDL has been established for nutrients and sediment. Deforestation, increased impervious surfaces and construction run-off have the potential to increase the amount of nutrients and sediment that reaches surface water.

Statewide regulations already in place governing stormwater controls, and other Statewide regulations that are planned, will minimize this increase. In addition, best practices have been proposed specifically for Marcellus Shale gas development to further reduce the risk of an impact to surface waters. For example, the Departments recommend as a mitigation measure that a no-net-loss of forest standard be implemented, varying for temporary or permanent loss. In order to prevent, minimize, or mitigate increased impervious surfaces, run off, or other water and land degradation, the Departments recommend that erosion and sediment, and stormwater management staff receive additional training, and mandate the use of closed loop handling of drilling mud and cuttings, “zero-discharge” pads, and various other practices, including the strict adherence to current requirements of erosion and sediment, and stormwater management regulations. In addition, drilling, well casing, HVHF, water appropriations and waste management practices will be tightly monitored and controlled in order to prevent contamination to local waters and the Bay.

In 2013, the Chesapeake Bay Program Scientific and Technical Advisory Committee (STAC) addressed this issue through a workshop on “Exploring the environmental effects of Shale gas development in the Chesapeake Bay Watershed.” One of the key recommendations from the STAC workshop was the development of a rigorous monitoring and analysis program in order to determine if impacts to the Bay were occurring. In addition, the STAC also recommended many of the same practices that Maryland is considering such as landscape scale planning at the project level vs. individual well level and a rigorous set of environmental setbacks to protect sensitive aquatic habitats and waterways. More information on the STAC workshop can be found here: http://www.chesapeake.org/pubs/300_Gottschalk2013.pdf.

In 2014, Maryland implemented a baseline surface and groundwater monitoring program to characterize pre-drilling conditions in the jurisdictions most likely to be affected by Marcellus gas well development. In addition and 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. This will ensure that any deviations from baseline conditions resulting from drilling are identified so as to be appropriately addressed.

2. As a result of recent legislation, most Marylanders will soon pay more in stormwater utility fees designed to fund the TMDL compliance efforts. Requiring Marylanders to pay more for stormwater protection while largely absolving the oil and gas industry from these efforts everywhere except the well pad is unjust.

The federal Clean Water Act requires Maryland and other States to meet water quality standards to protect public health and restore streams, rivers, groundwater and drinking water. The actions needed to achieve this include reducing the amount of pollution that ends up in our waters as a result of heavy rains washing contaminants off the land into our waterways. Under the authority of the federal Clean Water Act, the U.S. Environmental Protection Agency has required all Chesapeake Bay Watershed states to develop Watershed Implementation Plans (WIPs) to achieve the Chesapeake Bay Total Maximum Daily Load (TMDL) requirements for nitrogen, phosphorus and sediment. Meeting the TMDL will require us to address the existing sources of pollution as well as prevent or offset the new sources of pollution. The purpose of the stormwater remediation fee passed by the Maryland General Assembly in 2012 and mandatory in Baltimore City and the nine most populous counties of Maryland is to fund programs and projects to meet the stormwater pollutant load reductions mandated under Federal and State law. The money will be spent in the jurisdiction in which it is collected.

Various Statewide regulations are already in place to minimize the pollution that results from new development, including construction for roads and pipelines. Some of the recommended best practices will reduce the pollution further. In addition, the State is developing a program to offset the remaining nutrient and sediment pollution from new development.

Everyone in the watershed contributes to the stormwater problem and everyone must be part of the solution. The oil and gas industry is not excused.

INDIVIDUAL WELL PERMIT

1. It is noted that on page 20 operators are required to consider API standards and guidance documents in the preparation of well plans. This is consistent with some other states inclusions of API standards in their regulatory process and may work to improve the well planning process by incorporating the engineering rigor found in these documents. However, caution should be exercised in the application of these requirements. This is due to the fact that as performance based standards, a variety of engineering solutions can be found in these documents. The requirement that the plans must “follow a normative element of a relevant API standard” or otherwise “explain why and demonstrate that the plan is at least as protective as the normative element” could lead to conflicting requirements as performance-based standards often contain multiple normative elements which allow for the use of engineering judgment in their application.

The Departments agree that caution must be exercised in the use of API standards; however, the Departments do not think there is a significant risk of conflicting requirements. In API standards, “normative” elements are those provisions that are required to implement the standard. “Normative” corresponds to “shall,” which denotes a minimum requirement, while “should” denotes a recommendation or something that is advised but not required in order to conform to the standard. If a standard applies to an operation, there should be no reason not to conduct that operation in a way that provides at least the measure of protection provided by a mandatory minimum requirement.

2. The applicant should be required to notify the owners of any drinking water well within one kilometer (3,300 ft) of active development area outlined in the permit.

Current regulations require that the applicant for a permit certify that the applicant has notified, in writing, each landowner and leaseholder of real property that borders the proposed drillable lease area of the applicant's intention to file an application for a permit to drill a well. COMAR 26.19.01.06C(9). More recently in 2012, Section 14-110.1(c) of the Environment Article was amended to provide for a presumptive impact area of 2500 feet from the vertical well borehole. The Departments agree that all those within the presumptive impact area should be notified of the application and MDE will seek such a change in the regulation.

3. COMAR 26.19.01.10 V requires the permittee to provide the state with a copy of all electric, radiation, sonic, caliper, directional, and any other type of logs run in the well. The statement is too weak because it does not require the permittee to run all these logs.

Each well will be considered individually. The best practices report states that an application for a well permit must include a plan for integrity and pressure testing. There may be various combinations of logging done on individual wells. The Department of the Environment will specify in the individual permit the type of logging to be done. This could be codified in regulation but the greater flexibility of reserving the specifics for the permit decisions may be more advantageous.

4. The list of items from 1 to 26 is incomplete and is basically a list of terms. The list should specify what is required such as: locations of; project plans and specifications, plans, procedures and schedules. Requirements should be clear about the level of detail expected for each item.

The Departments agree and will clarify the required level of detail in the regulations and in the permit application form. The Department of the Environment has the right to ask for documents and information if necessary to complete the application and, if any of the elements are lacking in appropriate detail, it will exercise that right.

LEGISLATION

1. The State and the Advisory Commission should advocate for legislative protections like a Surface Owners Protection Act (SOPA). The Act needs to be comprehensive and address reasonable and fair consideration for the surface owner, with monetary compensation commensurate with the highest possible loss the surface owner could suffer as a result of drilling practices and drilling malpractices. The consideration for problems that are caused by drilling that will be discovered only as a matter of time need to be included.

The Departments and the Advisory Commission recommended in December 2011 that the legislature adopt a comprehensive SOPA. A committee of the Advisory Commission was formed to discuss, among other things, the provisions of a SOPA. The Commission unanimously agreed that a SOPA should protect surface owners who are not mineral rights owners; the SOPA should include a procedure for the negotiation of the siting wells, roads and other infrastructure; and that the SOPA should mandate reasonable compensation for damages. A motion passed, not

unanimously, that the SOPA should also apply to surface owners who lease their mineral rights in the future. There was no consensus on how to manage dispute resolution or whether the SOPA should protect those who leased their mineral rights in the past, to the extent permitted by the Constitution. The areas of agreement did not amount to a comprehensive SOPA, and the Departments decided not to proceed with an incomplete bill.

2. The Best Practices Policy, and any legal rights therein, should apply to contracts that were signed in the past.

Article I, Section 10 of the United States Constitution forbids any state from passing a law that retroactively impairs the obligation of contracts. The Advisory Commission was not able to reach consensus on whether the SOPA should protect those who leased their mineral rights in the past, to the extent permitted by the Constitution.

3. Landowners should be allowed to cancel any lease they entered into, even if it is after the company has begun drilling.

Such a blanket provision would likely violate Article I, Section 10 of the United States Constitution. See above.

4. Maryland should adopt an adequate State severance tax; the funds could be administered by a publicly appointed commission similar to the Marcellus Shale Advisory Commission or by an ombudsman panel.

SB 535 was introduced during the 2014 legislative session to levy a State-level severance tax. The taxes would go into a fund to be used by the State to monitor, mitigate and remediate adverse impacts caused by natural gas exploration or production that cannot be attributed to a specific permittee or where the permittee is financially insolvent or no longer exists. This legislation did not pass. The Departments do not see the need for a commission or an ombudsman panel to administer the fund.

5. We strongly urge the funding (via a severance tax) of a special conservation fund of \$100 million for restoration activities resulting from drilling legacy issues. The funds collected to address legacy issues are in addition and separate from funds that will be collected to address short-term environmental damages resulting from drilling.

The combination of financial assurances and pollution insurance should prevent the kinds of legacy issues that occurred in coal mining because regulations were not in place to require reclamation of the mines. The severance tax bill (SB535) that was introduced this year would have established a fund to be used by the State to monitor, mitigate and remediate adverse impacts caused by natural gas exploration or production that cannot be attributed to a specific permittee or where the permittee is financially insolvent or no longer exists. Under this legislation, if the amount in the fund were to exceed \$10 million, it could be used to benefit the area where drilling occurred. This could include conservation projects. This legislation did not pass.

6. The rights of resident communities should supersede any rights afforded to corporate interests and absentee owners.

The Departments have tried to strike a balance between the property rights and the interests of resident communities, both of which should be protected. The proposed best practices are designed to protect residents.

7. The agencies/MSAC should advocate in the 2014 Legislative session for a bill moving the PSC to regulate and permit rural gas gathering lines within the state. The regulations in COMAR Title 20, Subtitles 56, 57 and 58 are inadequate. The bill could also address permitting, siting, construction and operation of all pipelines outside the CGDP process.

The PSC has the authority to assure that intrastate gathering lines comply with the pipeline safety regulations. The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) is in the process of collecting new information about gathering pipelines in an effort to better understand the risks they may now pose to people and the environment. If the data indicate a need, PHMSA may establish new safety requirements for large-diameter, high-pressure gas gathering lines in rural locations. Pending this action, the Departments are recommending two simple and commonsense requirements: that the locations of the lines be registered through Miss Utility, and that all pipelines and fittings 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.

8. UMCES-AL recommends that applicants wishing to drill wells be required to notify property owners residing within the established setback that an application has been filed for development. This notification requirement should also apply to citing of compressor stations and other ancillary equipment. Applicants who wish to construct ancillary infrastructure are required to notify all landowners whose property line falls within the current required setback (1,000 feet.)

Current regulations require that the applicant for a permit certify that the applicant has notified, in writing, each landowner and leaseholder of real property that borders the proposed drillable lease area of the applicant's intention to file an application for permit to drill a well. COMAR 26.19.01.06C(9). More recently in 2012, Section 14-110.1(c) of the Environment Article was amended to provide for a presumptive impact area of 2500 ft from the vertical well borehole. The Departments agree that all those within the presumptive impact area should be notified of the application and MDE will seek such a change in the regulations.

Ancillary infrastructure will be considered in the Comprehensive Gas Development Plan (CGDP). The Departments will require that a similar notice be made so that interested persons can participate in the public process of reviewing the CGDP.

9. Any and all fracking companies that may be allowed to do business in Maryland should have to contribute substantially to a fund that helps significantly increase our renewable energy portfolio. That way at the very least the damage that fracking will inevitably do every step of the way will pave a path toward a green, healthy environment, economy and future.

It is not clear why natural gas companies should be required to contribute to such a fund when coal mining companies, for example, do not. Nevertheless, the Regional

Greenhouse Gas Initiative may provide a model for such a program, if offsets of greenhouse gas emissions were required. The money raised from the sale of offset credits directly funds energy efficiency and cleaner energy programs that will lower greenhouse gas emissions.

10. All legal hearings related to fracking/drilling will be held in the court system of that county. However, if it involves federal issues, it may be heard in the federal court system.

The question of the jurisdiction of federal and state courts is outside the control of the Departments. MDE regulations provide, for its own hearings, that “If the hearing relates to the issuance of a permit for or with respect to a specific well, it shall be held in the county or municipal corporation where the well is located.”

NOISE

1. Zoning and Noise. We strongly recommend that the BMP's recommend local zoning be adopted in Garrett County so that it can better protect its citizens in this regard. If the Commission will not recommend that local zoning is integral to best management practices, then would they, at a minimum, provide recommendations for specific zoning elements; e.g., noise.

Zoning is an excellent way to separate incompatible land uses; however, authority to enact zoning rests with the local jurisdictions. Allegany County has adopted comprehensive county-wide zoning; however, Garrett County has not. It is a local matter over which the Departments have no control. Even without zoning, however, Garrett County has adopted the state noise regulations, see § 157.063 of the Garrett County Code.

2. Noise and setbacks.
 - a. “Noise” is viewed as a potentially significant industrialization issue. We are having difficulty rationalizing the largely noise-driven setbacks appearing in this section with the noise discussion in Section VI.N. For instance, the setback table specifies 1,000 ft. between an occupied building and a compressor station, while Section VI.M seems to call for at least 3,000 ft. unless the only engine/motor source is electric. Something to be changed or explained? Are we misreading?
 - b. Wouldn't it be useful to calculate the implied setback distance from, say, active drilling rigs or compressor stations whose noise level at the source is surely known or readily measured?? Has this been done?? Is this the basis for Section IV setbacks though not explicit??
 - c. Beyond specifying setbacks broadly based on state-level standards as above, one could (1) identify specific residential or commercial facilities around a particular proposed well/well pad, (2) specify maximum noise levels at these specific locations as part of the application for each well (per local standards), and (3) mandate that the plan for each well/well pad include an analysis of how the standards will be met for the specific “noise sources” that are part of the industry application. (Will the well plans

include locations and design parameters of compressor stations as well as drilling rigs??)

The UMCES-AL report recommended requiring quieter equipment, restricting hours of operation, and using mitigation techniques like barriers and mufflers where natural noise attenuation would be inadequate. That report did not, however, indicate how to evaluate whether natural noise attenuation would be adequate, nor did it discuss the Maryland noise standards.

Setbacks alone cannot be a surrogate for noise regulations because topography and other site-specific issues greatly affect how noise travels. The Departments have chosen instead to require compliance with the statewide daytime and nighttime noise levels that are specific to the type of property that receives the noise and is being protected: residential, commercial or industrial. The Departments will require that the applicant for a permit submit a plan for complying with the noise standards for all its permitted operations and for verifying compliance after operations begin.

3. Noise levels and controls.

- a. Maryland noise statutes appear to be limited regarding low frequency noise. However, there is data to indicate that low frequency noise may be associated with natural gas infrastructure and specifically compressor stations. Noise can cause permanent medical conditions such as hypertension and heart disease, hearing impairment, communication problems, sleep disturbance, cognitive effects such as memory problems, reduced performance, behavioral symptoms, and more. Low-frequency noise [LFN] can also cause Vibroacoustic disease, leading to cardiovascular symptoms and decreased cognitive skills. We believe it is incumbent upon Maryland to ensure that adequate protections are in place to protect against LFN. Typical noise mitigation measures for gas supply and storage infrastructure include acoustic cladding for buildings, the use of sound attenuators on ventilation systems, acoustic lagging on pipework, multi-stage control valves, gas turbine exhaust silencers, acoustic enclosures on pumps, low speed cooler fans and the use of electric rather than gas powered compressors.
- b. Require that all compressors and other above ambient levels noise-creating equipment be fully enclosed and muffled to normal ambient levels.
- c. Add: Sound levels should not exceed 115 dBa at any time.
- d. You should address noise from drilling rigs and compressor stations and idling trucks, especially at NIGHT!
- e. Instead of using “residential” consider using “noise-sensitive locations.” This would allow expansion to incorporate a number of other non-residential noise sensitive areas including areas identified for environmental considerations in this report. Noise sensitive uses may include uses such as hospitals and parks.

Most noise standards, including Maryland's, are based on A-weighted measurements that deemphasize or ignore low frequency noise. The effects of infrasound and low frequency noise are being studied and the Departments will consider changes to the noise regulations in the future if evidence justifies it. A few studies have suggested that excessive exposure to low frequency noise can cause a condition which has been termed vibroacoustic disease (VAD). However, the strength of these studies and the significance of their conclusions are uncertain, and it does not appear that VAD has been established as a known medical condition outside of these studies.

With respect to compressor stations, the statewide noise regulations will apply to any stations over which Maryland has control. Interstate compressors are authorized by the Federal Energy Regulatory Commission (FERC) under a Certificate of Public Convenience and Necessity (CPCN). For efficiency of administration, FERC has established a blanket certificate program as well as a site-specific process for issuing CPCNs. Both require adherence to maximum noise limits at noise sensitive areas in existence at the time of the CPCN. Noise sensitive areas include schools, hospitals, and residences. A noise survey must be conducted after the compressor station is in operation and, if the noise levels are exceeded, corrective measures must be taken.

No foundation was offered for reducing noise to "normal ambient levels" or to add a never-to-be-exceeded sound level. These approaches are not consistent with noise regulation in Maryland which focuses on levels that must be maintained at the property line of affected entities.

The noise standards are lower for nighttime hours than for daytime hours.

Recognition of "noise sensitive locations" is a good suggestion, and the Departments will incorporate that concept into the review of the Comprehensive Gas Development Plan and the individual well permit. Site-specific noise provisions can be incorporated into individual permits.

4. Monitoring and reporting.

- a. Making the industry responsible to monitor and report excess noise levels may not produce accurate reporting. The permittee should be required to have continuous monitoring for sound during high development activity; such as stimulation of the well. Funding for this monitoring will be paid by the permittee, with all reports to be received by MDE for compliance of the permit. We recommend that the Departments require the County to select and hire an independent contractor—at the expense of the permittee—to conduct periodic noise monitoring and additional noise monitoring in response to a complaint.

As noted above, the Departments will require that the applicant for a permit submit a plan for complying with the noise standards for all its permitted operations and for verifying compliance after operations begin. In the draft Best Practices report, the Departments indicated that they may require the permittee to hire an independent contractor to conduct periodic noise monitoring and additional noise monitoring in the event there is a complaint. The reports would be submitted to MDE and any necessary compliance investigations will be carried out by the local jurisdiction. In

determining the amount of the application and permit fees the Department is authorized to set under Section 14-105 of the Environment Article, MDE will consider whether funds will be needed to purchase noise monitoring equipment.

PRE-DEVELOPMENT BASELINE DATA

1. We believe that there is a strong need for pre-development testing of water wells and aquifer samples within a kilometer of leased mineral rights for a number of elements, along with isotopic fingerprinted methane.

As stated in the draft report, the Departments will develop standard protocols for baseline and environmental assessment monitoring. This will include sampling existing private drinking water wells within 2500 feet of the proposed gas well, provided the owner of the drinking water well consents to the sampling. If there are no drinking water wells within that distance, the Department of the Environment will require the installation of one or more monitoring wells. Isotopic analysis for methane can only be performed if there are high enough concentrations of methane. It will be required if circumstances warrant.

2. The State needs to develop specific requirements for surface water testing parameters, whether there will be baseline monitoring of air quality, and what living species and habitat will be monitored.

The Departments, in collaboration with University and government researchers, have developed a comprehensive monitoring plan for surface waters associated with Marcellus Shale natural gas development in western Maryland (if and when it is permitted). The draft monitoring plan is currently under review and will be included in the final draft report when it is posted for comment. The sampling approach recommended for evaluating the impacts of Marcellus Shale gas extraction on surface waters uses a BACI (before-after-control-impact) model. The sampling design will measure conditions in stream/river reaches associated with the development of a particular gas well pad (or associated infrastructure) BEFORE (baseline monitoring) the planned activity, and then compare the findings to those conditions measured in the same stream/river reaches during and AFTER the activity occurs. The recommended monitoring plan also includes measurements of stream/river conditions in CONTROL stream/river reaches that will not be affected by gas extraction-related activities, and then will compare these data with measurements of stream/river conditions in affected or IMPACTED stream/river reaches. Data collected from stream reaches include continuous conductivity and temperature, a full suite of water chemistry parameters (including all or a combination of inorganic constituents, gross alpha and beta, polycyclic aromatic hydrocarbons, surfactants, and stream methane) and characterization of the biological communities (e.g., fish, benthic macroinvertebrate, and presence/absence of golden algae).

3. Two years of background data is not necessary. At least, consideration should be given to whether there is already sufficient data available. The need for monitoring and the area to be monitored should be related to the tract size.

In 2012, The Maryland Department of Natural Resources evaluated its existing monitoring networks in Garrett County and determined that data exists for about 10 percent of all stream or river reaches present. In addition, DNR determined that although the existing data is good information (i.e., quality data), it is limited (i.e., lacks parameters identified as important to assess impacts from Marcellus Shale gas development) and addresses a different set of management questions.

The first draft comprehensive monitoring plan developed by the Departments recommended at least three consecutive years of stream/river monitoring to establish baseline conditions. Three consecutive years of monitoring could provide a reasonable opportunity to collect data during a wet, dry, and near-normal precipitation year. Two years of baseline monitoring are less likely to capture a wet and a dry year and will probably fail to document the full or nearly-full range of annual fluctuations in stream/river conditions. If only one year of pre-drilling stream/river monitoring is conducted, useful information on seasonal fluctuations can be collected for that year and that year only. One year of baseline data cannot document annual fluctuations in conditions at a given stream or river location.

4. Pre-operational sampling to establish background air quality should also be required for ancillary facilities, such as compressor stations, that have the potential to emit gases.

There are other ways to monitor air quality in the vicinity of compressor stations and methods for detecting leaks. Pre-operational sampling is not necessary.

PROCESS

1. We are concerned about the Marcellus Shale Safe Drilling Initiative Advisory Commission as it relates specifically to transparency in decision-making process. How are reports developed: is it by vote, by building consensus, are votes public, can there be dissenting reports, and specifically, are all the stakeholders' positions made public? These are concerns we have so that we understand better how decisions and reports are accomplished. We wish to know whether all stakeholders' views are represented and where divided opinion exists.

The Marcellus Shale Safe Drilling Initiative Advisory Commission provides full transparency through open meetings and through a dedicated website providing access to all documents, meeting minutes, presentations and other materials used for discussion. One example of transparency is a report of the Commissioners' responses to a survey that was designed to elicit their opinions on proposed best practices. The purpose of the survey was to identify which topics required further discussion at upcoming Commission meetings. The individual responses are posted on-line.

The composition of the Commission is designed to provide representation across all stakeholder groups. In addition, stakeholders have the option to provide their viewpoints to the Commissioner best suited to represent their views and to participate in the public comment period at the end of each Commission meeting. The Marcellus Shale Safe Drilling Initiative reports are produced by the Departments and are informed by the discussions that take place at the Commission meetings. The final

version of the best practices report will document the recommendations of the Departments and document the degree of consensus among the Commissioners.

The Departments seek to identify points of consensus among Commission members and also realize that there may be dissenting opinions.

2. We are concerned that, in some cases, the UMCES-AL Best Management Practices Report and Recommendations are weakened rather than followed or strengthened. Will Commissioners be able to vote on these changes made by MDE?

In most instances, the Departments accepted the UMCES-AL best practices recommendations, and, in certain situations, strengthened them. Justifications for recommendations that the Departments rejected or modified are clearly identified in the report. Additional changes are being made in the report as a response to comments. The Departments will consult with the Commission on the final set of best practices recommendations.

3. The BMPs are vague: the proposed BMP's have language such as "where practicable," "encouraged," and "reasonable use." "Where practicable" is used six times in the proposal, "encouraged" is used three times, and "reasonable use" is used eight times. That is a total of 17 occurrences where common understanding is likely not to occur. Also, monitoring and enforcement are far more difficult when regulations and/or BMP's use such language. How can penalties be instituted, if at all, with such vagueness?

"Practicable" is a term often used in laws and regulations. It is used interchangeably with "feasible" and describes an idea or activity that can be brought to fruition or reality without unreasonable demands. In the draft Best Practices report, "practicable" is often used in connection with a plan that, once approved, becomes part of the permit. For example, the draft report says "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." The applicant for a drilling permit must submit a plan for storage, treatment and disposal of water and wastewater. The Department of the Environment will review that plan, and any claim by the applicant that recycling is not practicable. The approved plan, which will be incorporated into the permit, will be specific as to the recycling and sufficiently clear to determine compliance or noncompliance.

"Encouraged" is often used in the draft report in circumstances where the Departments have no legal authority to require a certain action, or to indicate the Departments' preference where there are multiple permissible options.

"Reasonable use" is the name of a doctrine or policy on water rights. Maryland regulations state: "Maryland follows the reasonable use doctrine to determine a person's right to appropriate or use surface or ground water. A ground water appropriation or use permit or a surface water appropriation or use permit issued by the Department authorizes the permittee to make reasonable use of the waters of the

State without unreasonable interference with other persons also attempting to make reasonable use of water. The permittee may not unreasonably harm the water resources of the State.” COMAR 26.17.06.02.

4. The report should not be limited to the Marcellus Shale because the Utica and other formations may also be tapped in the future.

The findings and conclusions regarding gas exploration in the Marcellus Shale may also apply to other formations. That question will have to be considered if and when other productive formations are identified.

5. We reiterate our recommendation that this “Study Part II” include a new section that outlines and states the goals and policy direction for Marcellus gas development in Maryland. By clearly stating the direction Maryland is taking, all stakeholders (the industry, landowners, local government, interested and concerned parties, and statewide parties) can see and understand the purposes and intended uses of the best practices.

*Goals and policy directions are provided in the publicly available Executive Order 01.01.2011.11. The State is still in the process of collecting the facts and evaluating the science and has not settled on a “direction.” As stated in the Executive Order, the State is determining the best way Marcellus gas development **could** be done in Maryland without risk to public safety, public health and the environment, and to advise the Administration on the remaining risks. Also note that the report development process includes opportunities for the involvement of all types of stakeholders, including representation on the Advisory Commission and the chance to provide comment on report content.*

6. The report is based on the recommendations of the contractor, UMES-AL, and therefore does not take a “systems” view of the full breadth of Marcellus gas development. First, this report should identify additional best management practices that are recommended for other state and local government departments and agencies so their activities can be coordinated and responsive to the overall thrust of the Safe Drilling Initiative. Second, the report appears to have selectively identified BMP’s for the industry, but does not clearly identify the BMP’s that should be adopted by state agencies. It is important that BMP’s be recommended and adopted by state departments as well as the drilling industry as the Marcellus is developed.

The report addresses methods and techniques for the actual operations of gas exploration and production, planning, opportunities for other state and local agencies to participate, and processes for government review. The CDGP and other best practices will address all aspects of the Marcellus shale gas drilling activity. Certain elements of the best practices report will be implemented by MDE and DNR or through partnerships with county and local authorities. If the decision is to allow Marcellus shale gas development, the Departments anticipate that the recommendations will be embodied in regulations and guidance.

7. The CGDP as presented by the Departments is a conceptual outline and has not come under broad scrutiny by the public, the industry, and elected government representatives.

The CGDP has been presented as a concept, but with a significant amount of detail regarding principles, content, and process. The Departments are confident that it is clear enough for interested persons to understand and comment on.

Before any individual permit for a production well is issued, the applicant must have an approved CGDP. The development and approval of the CGDP requires evaluation by local and state agencies, followed by a public review, involving a stakeholder group, and approval process. The stakeholder group will include the company, local government, resource managers, non-governmental organizations, surface owners, and other affected individuals or organizations. This transparent and public process will provide ample opportunity for scrutiny of actual CGDPs.

8. The study should explicitly acknowledge the political reality that the proposed “best practices” amount to an initial negotiating position held by Maryland, in the face of oil and gas industry pressure.

All stakeholders, including oil and gas industry representatives, have had the opportunity to provide comment on the content of the best practices report. It is up to the State to determine which best practices will ultimately be required.

9. Standards and practices are changing constantly. What was a good practice or standard last year when the study was conducted may have been superseded with better practices or proven to not provide protections it was designed to provide. We could not find a process by which there is on-going updating and evaluation of BMPs as the study process moves forward.

The Departments acknowledge that standards and practices change. The best practices in the report do not preclude the use or introduction of new and innovative technologies. If this type of gas activity is allowed, the development of the industry will be closely tracked by State agencies through comprehensive monitoring of environmental conditions, best practice performance monitoring and rigorous inspection and enforcement procedures. This information will be used as a benchmark for identifying and implementing additional practices that may better protect the environment, public health and safety and the community. If needed, regulations will be updated.

10. I much prefer a regulation that requires the introduction of new best practices by the industry as new technologies emerge that can provide more protection to public health and safety and to the environment. Better technology requirements could be a requirement every five (?) years if improvements exceed some pre-set thresholds, e.g. a reduction of some air pollutant by 20 percent.

As stated in the previous response, the State will closely monitor the performance of the industry and identify opportunities to adopt best practices that are more protective of public health, safety and the environment. The industry is rapidly developing new technologies and practices for extraction of shale gas. The Departments prefer to retain flexibility rather than setting thresholds or time limits,

to ensure the rapid adoption of new technologies should monitoring confirm improved performance. With respect to air pollution controls, the Departments are proposing to require best available control technology.

11. We are very supportive of the best practices report as drafted. As an organization that works on the issue of unconventional gas development across the country, these BMPs, if adopted into regulation in Maryland, would be some of the best, if not the best, in the country. However, we are concerned that the timeframe for the development of regulations from these recommended Best Practices is indefinite. We understand that there are public concerns about the development of new oil and gas regulations before the full report from the Commission is available. However, current Maryland regulations on oil and gas are outdated. Regardless of whether someone supports or opposes shale gas development, it serves the State to have the best regulations in place to protect the health, safety, and natural resources of Maryland.

The Departments agree that current regulations are outdated and that it is imperative to update the regulations in the event that shale gas development is permitted in the State. In an open letter to the public from Secretary Robert Summers, dated April 26, 2013, MDE commits to proceeding methodically and cautiously to develop stringent regulations that will protect Marylanders in the event hydraulic fracturing is allowed. As a preliminary step, the Departments must first finalize the best practices report and review the additional results produced from the ongoing economic, public health and risk studies, before proposing any specific regulatory revisions.

CLASSIFICATION OF WASTES UNDER THE RESOURCE CONSERVATION AND RECOVERY ACT (RCRA).

1. If drilling were to proceed in Maryland, COMAR regulations should treat wastes from oil and gas facilities as RCRA hazardous materials. As the Departments are aware, the EPA in 1988 determined oil and gas wastes as nonhazardous despite acknowledging that known toxics like benzene appear at high levels. While many of the same chemicals found in oil and gas production the EPA already regulates as hazardous, once these same materials emerge from gas wells as flowback or produced water, the law exempts them from this treatment.³⁵ The reason Maryland should treat oil and gas waste as RCRA hazardous is that EPA's 1988 determination is out of date.

For the reasons explained below, MDE believes that wastes from oil and gas production can be managed safely under the existing practices, as augmented by the

³⁵ *We would like to correct one error in the commenter's statement, namely that "While many of the same chemicals found in oil and gas production the EPA already regulates as hazardous, once these same materials emerge from gas wells as flowback or produced water, the law exempts them from this treatment." The statement implies that the chemicals used in oil and gas production are regulated under RCRA as hazardous before they "emerge from the gas wells." EPA does not regulate materials as hazardous under RCRA until they become wastes. When chemicals are in commerce or in use, they are not wastes and therefore cannot be hazardous wastes.*

new best practices, without classifying them as hazardous wastes. Therefore the Department does not propose to eliminate the exemption at this time.

In 1988, EPA announced its determination that regulation of wastes from the exploration and production of oil and gas did not warrant regulation under Subtitle C of the Resource Conservation and Recovery Act (RCRA) that applies to "hazardous wastes." The exemption is codified at 40 CFR 261.4(b)(5), which provides: "The following solid wastes are not hazardous wastes: ... Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." Maryland adopted an identical regulation.

As directed by Congress, EPA in 1988 considered three major factors: 1) the characteristics, management practices, and impacts of these wastes on human health and the environment; 2) the adequacy of existing State and Federal regulatory programs; and 3) the economic impacts of additional regulations on the exploration and production of oil and gas.

Data on the characteristics of the wastes were sparse in the 1980's, and HVHF wastes were not tested (and probably not being generated by the industry in 1988). EPA reported, however, that

For crude oil and natural gas wastes, EPA sampled liquids and sludges from several locations. Drilling fluids were sampled at drilling operations while produced water and tank bottoms were sampled at production operations. Samples from central treatment and disposal facilities and central pits contained mixtures of all wastes including associated wastes. The Agency found that organic pollutants at levels of potential concern (levels that exceed 100 times EPA's health-based standards) included the hydrocarbons benzene and phenanthrene. Inorganic constituents at levels of potential concern included lead, arsenic, barium, antimony, fluoride, and uranium.

53 Fed.Reg. 25446, 25448 (6 July 1988).

EPA concluded that some of the wastes would be classified as hazardous if the exemption were lifted. "EPA estimates that approximately 10 to 70 percent of large-volume wastes and 40 to 60 percent of associated wastes could potentially exhibit RCRA hazardous waste characteristics under EPA's regulatory tests." 53 Fed.Reg. 25455.

EPA also evaluated the waste management techniques in use in the 1980's.

Current practices include the use of reserve pits for drilling wastes; landspreading of reserve pit contents; disposal of produced waters through Class II underground injection wells; disposal of produced water in unlined pits; discharge of produced water to surface waters; roadspreading; use of commercial facilities for treatment and disposal of drilling wastes and produced water; and some practices unique to the Alaska North Slope.... Less frequently used current practices discussed in the report are closed-cycle drilling

mud systems, annular disposal of produced water and drilling fluid, and trenching of reserve pits to dispose of reserve pit fluids.

53 Fed. Reg. 25448-49.

EPA considered the damage that has been caused by oil and gas operations. It concluded that wastes from crude oil and natural gas operations have endangered human health and caused environmental damage when managed in violation of State and Federal requirements. Moreover, in some instances damage occurred even where wastes were managed in accordance with then-applicable State and Federal requirements. 53 Fed.Reg. 25449.

On the question of whether existing State and Federal regulatory programs were adequate, EPA concluded that there were gaps in the existing programs but that they could be corrected without regulating oil and gas wastes under Subtitle C of RCRA.

State and Federal regulatory programs are generally adequate for controlling oil, gas, and geothermal wastes. Regulatory gaps in the Clean Water Act and UIC program are already being addressed, and the remaining gaps in State and Federal regulatory programs can be effectively addressed by formulating requirements under Subtitle D of RCRA [the nonhazardous waste requirements] and by working with the States.

53 FR 25447.

With respect to the third issue, EPA concluded that “For the nation as a whole, regulation of all oil and gas field wastes under unmodified Subtitle C of RCRA would have a substantial impact on the U.S. economy” 53 Fed.Reg. 25453.

Considering all the factors, EPA concluded that “regulation of all crude oil and natural gas wastes under RCRA Subtitle C is unnecessary and impractical. The Agency believes that these wastes can be managed in a manner so as to protect human health and the environment without regulating them under RCRA Subtitle C.” 53 Fed.Reg. 25453.

Looking at the situation in 2014, we note that some flowback and produced water from HVHF contain some constituents at greater than 100 times drinking water standards. If the exemption were not in place, it is possible that these wastes would qualify as hazardous. When these wastes are mismanaged, they have the potential to cause damage. The Departments believe, however, that the deficiencies in the regulatory programs of the 1980’s have been corrected, in particular with regulations for landfills that receive non-hazardous industrial wastes. In Maryland, specific waste management and disposal practices will be mandated for HVHF wastes, if that activity is allowed in Maryland. Some of the practices common in the 1980’s, such as the use of reserve pits for drilling wastes; landspreading of reserve pit contents; disposal of produced water in unlined pits; and discharge of produced water to surface water, will be specifically prohibited.

As a practical matter, if Maryland were to eliminate the exemption, and some wastes generated exhibited a hazardous characteristic, the wastes would be considered

exempt again as soon as they left Maryland. Maryland's action would not have any effect on the way the wastes were ultimately treated or disposed of in another state.

There is a legal consideration as well. If the exemption were eliminated, the persons generating the wastes would have to determine whether the wastes exhibit one of the four characteristics that cause a waste to be classified as a hazardous waste. While some HVHF wastewaters might exhibit the Toxicity Characteristic, that characteristic is measured by a specific test (the Toxicity Characteristic Leaching Procedure (TCLP), test Method 1311 in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846) that is meant to simulate the behavior of waste when it is co-disposing with municipal refuse or other types of biodegradable organic waste in a sanitary landfill. Because flowback and produced water are never managed this way, it is questionable whether application of a TCLP test to classify a waste as hazardous could withstand legal challenge.

RISK ASSESSMENTS

1. Best practices cannot be established without first performing a risk assessment. Until these risks are thoroughly studied, any attempts to set regulations for fracking are premature. Your "Best Management Practices" report on fracking in Maryland fails to adequately address the full scale and severity of these risks. The report puts the cart before the horse since the state has yet to even begin a thorough analysis of the unique risks of drilling in Maryland. Without this risk analysis, the state is moving blindly in developing "best practices."

One cannot evaluate a risk without having a fairly specific understanding of how the activity will be carried out, and with what safeguards. Best practices and risk assessment can be thought of as iterative processes: if an activity conducted using best practices still poses a significant risk of harm, further safeguards or mitigation measures can be considered.

Dr. Eshleman was asked to identify practices that would protect air quality; isolate the gas well from the surrounding formations, including aquifers; protect water resources from contamination, degradation and depletion; protect terrestrial habitat and wildlife; protect aquatic habitat, wildlife, and biodiversity; protect public safety; protect cultural, historical, and recreational resources; protect quality of life and aesthetic values; and protect agriculture and grazing. Therefore, the scope of work for the best practices study was developed with an understanding of the risks.

Even though the Executive Order does not require a risk assessment, the Departments are undertaking a qualitative risk assessment. It will inform the findings and recommendations on whether and how hydraulic fracturing can be done in Maryland without unacceptable risks.

2. As fracking has occurred in neighboring states, concerns about harm to water, air quality, health, and local economies have increased. I believe these potential impacts must be weighed closely against the benefits these operations offer to the LOCAL economy.

The State is undertaking a qualitative risk assessment, and has commissioned an economic study to assess the potential positive and negative effects Marcellus Shale

drilling. All of these issues will be considered in the final report. A public health study is also being conducted to specifically focus on the public health implications of unconventional gas well development.

3. I do not believe that it is possible to know how to minimize the impact to sensitive resources, without first fully understanding the specifics and the magnitude of the impact.

The State is undertaking a qualitative risk assessment that will consider the probability of adverse impacts and the magnitude of the impacts.

4. Fracking uses immense amounts of fresh water which is irreplaceable, and that effect occurs even when other damage might (or might not) be successfully minimized.

Both surface and groundwater withdrawals will be considered during the qualitative risk assessment planned by the Departments. Also the Department of the Environment believes that current appropriation regulations found in COMAR 26.17.06.05 are adequate to address water withdrawals associated with Marcellus shale gas drilling.

5. Spend and/or acquire the funding to do a comprehensive Risk Assessment. Identify any data gaps in the BMPs, issue requests for studies to complete those missing components, complete all of the other studies and then inform the BMPs from those studies.

The Departments are undertaking a qualitative risk assessment for Marcellus shale gas drilling activities in Maryland. The risks will be evaluated assuming the recommended best practices are adopted. If there are high risks, the Departments will consider whether additional best management practices could reduce the risks.

6. The CGDP section mentions mitigation in several places but fails to mention or recognize that mitigation is an integral part of the risk analysis process in which activities that have high risk are addressed by risk management alternatives to address mitigation as well as alternatives that will lower a risk. We believe that the Departments must not circumvent details for critical planning, siting, and environmental assessment needed for the large landscape level development plans.

The risks will be evaluated as if the recommended best practices have been adopted. The Departments will consider additional practices and mitigation for high risk activities.

SPREAD OF FRACTURES

1. Upward propagation of fractures.

The technique of hydraulic fracturing enhances the permeability of the host rock so that the trapped resident gas can be released to the land surface. When the fracking fluid is depressurized, solid-particle proppants, which were introduced along with the fracking fluid, remain behind to keep the fractures propped open, which maintains the immensely enhanced permeability.

The disciplines of Geomechanics and Geohydraulics are central to understanding and predicting the initial hydraulic generation and propagation of fractures within the host rock. Multiphase Flow is central to understanding the initial intruding movement of the proppants and the subsequent non-movement of proppants in response to depressurization within the newly formed fractures. Aquifer Mechanics is central to predicting the gradual upward migration of zones of enhanced permeability that will bring methane and possibly other contaminants into the overlying freshwater aquifers. These hydro-geo-mechanisms could result in seismic events and the introduction of chemical pollutants. In this view, hydrofracking wells inherently function as injection wells. The initial response of the subsurface geologic beds to quantifiable injection stresses would be identical. The likely time-delayed deformational effects on overlying aquifers must be addressed whether the wells inject waste materials in Pennsylvania that are collected at a well site in Maryland or, even more drastically from the mechanics point of view, whether the Maryland wells simply inject water, proppants, and undisclosed chemical additives within a concurrently expanding and extending new fracture at depth.

The gradual upward migration of newly formed fractures in massive rock and the correlated upward migration of zones of enhanced permeability in saturated particulate-based beds such as aquifers, should be considered. Laboratory tests indicate unequivocally that any slight change of porosity of particulate-based aquifers (sand, clay, sandstone, claystone, etc.) changes the corresponding permeability exponentially. This enhancement, in turn, directly affects the upward density flow of gas into and through any aquifer towards the land surface and into the overlying atmosphere.

Aquifer mechanics and the upward migration of fractures have been studied, measured, and modeled in the American southwest. This is because such features and their results are more observable in arid regions. The water table is often hundreds to thousands of feet below land surface and an upward migration of a crack can be identified through the brittle unsaturated overburden. Initially, arid zone hydrogeologists borrowed concepts and equations from the mining industry who appropriately use a bending beam analogy. But a crack in a bending beam that is applicable to underground mines migrates from the top downwards, contrary to hydrogeological observations in the field. These same mechanisms, empirically corroborated in the American southwest, are applicable to hydraulic fracturing anywhere and to the likely unavoidable gradual upward migration of these fractures, especially when proppants remain in place.

It is important that the required microseismic and tiltmeter data gathered early at each well be made available to State authorities, MDE, MDNR, the academic community, and to the general public, along with any interpretations.

While gathering this microseismic and tiltmeter data, the operator can use other early data in order to determine the principal directions of in situ regional stresses at MDE and MDNR designated locales of interest. Such a determination can be made by the operator from a well-known standard procedure while inducing an initial or a more modest pre-initial hydraulic fracture. This information will help

greatly to map in advance the direction of fracture propagation induced from any specified horizontal line or vertical borehole. After reaching a reasonably short distance from the borehole or line, the direction of propagation becomes controlled by the pre-existing regional stress field.

There is a deafening silence in Maryland's Best Practices Report (Draft) regarding the likely eventual contamination of fresh-water aquifers by the hydro-geo-mechanisms mentioned above. For example, Departmental Response 4-K (p. F-10) says that consideration of underground injection wells is deferred because it is not likely that any will be located in Maryland. Methane gas WILL enter the drinking water. The only question is when, where, and at what rate. The answer to this question is location specific. Polluting chemicals may well follow the gas. The physical and chemical characteristics of these pollutants will determine if, when, and where. The entirety of all horizontal lines are likely sources of vertical-flow contamination.

The recommendation (Appendix F, Table of Recommendations 1-F) to analyze groundwater flow by developing flow nets tacitly presumes unchanging flow conditions and therefore is preliminary. We cannot estimate the response to dynamic events (such as fracking events and also aquifer pumpage by county residents) with static presuppositions. Depending on the available data, it might, however, give a glimpse into the initial regional groundwater flow conditions and directions. Such a glimpse is highly beneficial but is not sufficient. Changes to the quality of water cannot be foreseen or forestalled if the directions and timings of groundwater flow remain unknown and ignored even by the State. Actual measurements and knowledge of already changed chemicals in the water are necessary, but such knowledge may be too late to affect a timely response. Aquifer amelioration, if possible, in response to such knowledge may be too expensive. Accurate and informed modeling of future changing flow patterns is not only critical, it is cheaper.

Assuming a statically safe buffer zone is questionable. Changes in the vertical permeability will occur and cannot be ignored. This occurrence is dynamic because the changes migrate upward with time.

In order to hydrofrack in the first place, the water pressure had to have been larger than the minimum in situ principal stress within the shale. Any induced fracture whose interior tensile pressure is maintained at depth, whether by continuing to inject new water (to maintain its interior hydraulic pressure) or by proppant-to-proppant stresses, will continue to expand in the local direction of minimum resistance. In order to accomplish this feat most easily and efficiently, the fracture's interior walls migrate upward rather than outward. In principle, such a fracture will gradually increase its length forever.

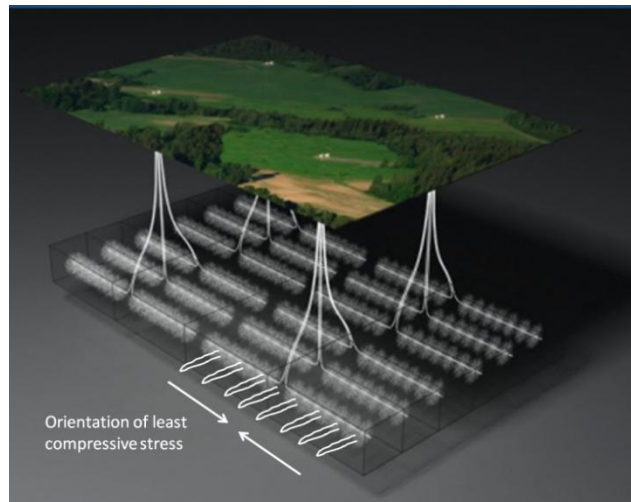
A recent study (ongoing) by the National Energy Technology Laboratory (NETL) for the Department of Energy (DOE) found that fractures in 1 in 8 wells had traveled up to 1,800 feet beyond the well bore, and federal regulators have accepted industry arguments that fractures may travel up to 2,000 feet.

Dominion wrote in a filing before FERC that there is no proven model or technology that can accurately predict the location and extent of encroachment of a hydraulically fractured shale well. The horizontal laterals may deviate from the intended path trajectory.

The basic premise of these comments is that any fracture propagated in the shale will continue to spread indefinitely in an upward direction, eventually reaching the surface. The commenter cites a study published in 1994 that addressed the origin of large surface cracks that formed as a result of groundwater withdrawal in Nevada. The commenter postulates that the proppants that lodge in the induced fractures supply a continuing force or stress that will cause the fractures to continue to grow in an upward direction. The commenter also states that these growing fractures can act as a pathway for vertical migration of methane and fracking fluids from the target formation to drinking water aquifers.

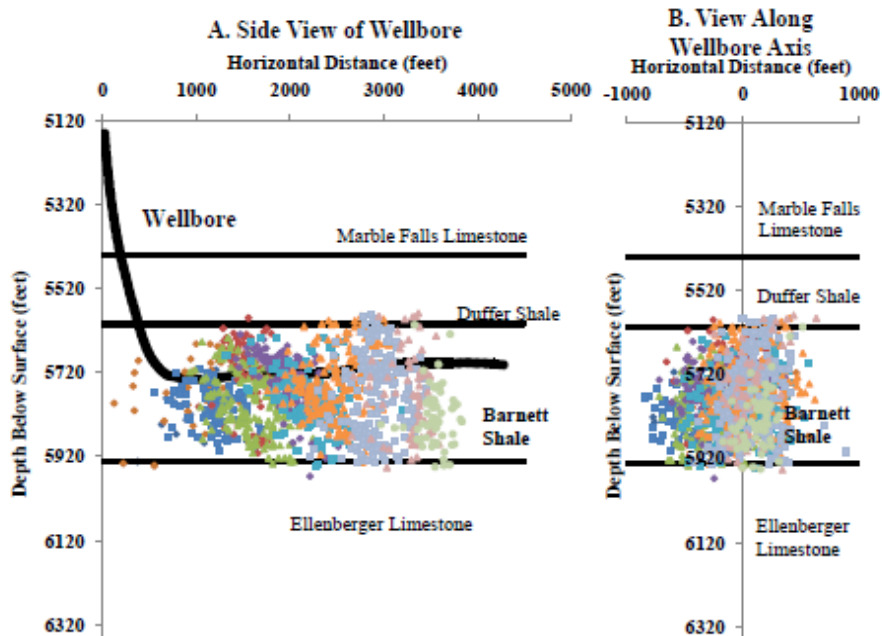
Geologists from MDE, DNR and the USGS reviewed these comments and concluded that it is unlikely that fractures induced in the Marcellus shale in Maryland would continue to propagate to any great distance in an upward direction after the hydraulic fracturing pressure is released to form a pathway for the migration of methane or fracking fluid. Briefly stated, their reasons include:

- i. The circumstances leading to the appearance of surface cracks in Nevada, as described in the 1994 paper, are not at all similar to Marcellus hydraulic fracturing operations. Nevada is in the Great Basin, a geologic setting characterized by extensional (pull-apart) tectonics. In such settings, groundwater withdrawal from sedimentary aquifers results in land subsidence and, sometimes, associated surface cracks, often located in proximity to extensional faults. Western Maryland's geology is dominated by hard, lithified and fractured sedimentary rocks which have been tectonically compressed. Groundwater withdrawal in Western Maryland is not known to produce any surface cracks.*
- ii. Hydraulic fractures form with an orientation perpendicular to the least compressive stress. At depths less than 2,000 feet, the overburden is the least principal stress, and if pressure is applied, fractures will preferentially form in the horizontal plane. Within Garrett County and westernmost Allegany County, the Marcellus is 5,000 to 9,000 feet deep. At these depths, the dominant stress is the weight of the overburden pressing downward, and the least principal stress is horizontal. Fractures induced at these depths will be oriented vertically. The ideal fracture can be visualized as a knife blade extending laterally straight out from the borehole with the cutting edge of the knife straight up (or straight down). See diagram below. If the pressure opens micro-fissures, micro-fractures and weak zones within the shale, it creates a network of connected fractures that can be compared to the network of cracks in shattered glass.*



Conceptual drawing of multi-well pads with additions from Chairman David Vanko showing the orientation of least compressive stress and the resulting shape and orientation of induced fractures.

- iii. *If a fracture were to reach a boundary where the principal stress direction changes, the fracture would attempt to reorient itself perpendicular to the direction of least stress. Therefore, if a fracture propagated from deeper to shallower formations it would reorient itself from a vertical to a horizontal pathway and spread sideways along the bedding planes of the rock strata.*
- iv. *In the Barnett shale, induced fractures appear to extend about 100 feet up and 200 feet down from the location where hydraulic fracturing pressure is applied, but 600-800 feet to the left and right. See diagram below. Although fractures have been mapped to extend upward as much as 2,000 feet in the Marcellus shale, most fractures that have been mapped are significantly shorter.*



Figures 4A and B from *Addressing the Environmental Risks from Shale Gas Development* (2010), M. Zoback, S. Kitasei, & B. Copithorne, Worldwatch Institute, Briefing Paper 1. Each dot in Figure 4A and B represents a microseismic event induced during hydraulic fracturing of an actual well in the Barnett Shale, with each color representing a distinct fracturing stage.

- v. *The pressure of the fracking fluid opens the fractures. The pressure might be applied for a period of a few minutes or a few hours. It will immediately begin to decrease, however, as the fluid contacts more rock and the fracking fluid leaks into permeable formations. When the pressure no longer exceeds the pressure at which the rock will break, fracture growth will cease. Proppants keep the fractures open when the pressure is fully released. Most geologists would not expect the proppant to act as an additional stress that would cause the fracture to continue to grow because there are other phenomena that act to reduce the pressures and stop the fracture growth. Shale contains clay that is somewhat plastic and could flex, reducing pressure and stress. The fractures would be in communication with the perforated casing in the horizontal borehole, and methane and formation water in the fractures would enter the borehole, releasing additional pressure. Fractures would stop if they reached rock more resistant to breaking than the shale. And, as noted above, if a fracture propagated from deeper to shallower (less than 2,000 feet deep) formations it would reorient itself from a vertical to a horizontal pathway and spread sideways along the bedding planes of the rock strata.*
- vi. *The period of high pressure operation is probably the only time most wells will experience pressures high enough to cause fluid to flow into the*

formation. In normal circumstances, the methane, fracking fluid and water in the formation, like other gases and fluids, tends to flow from an area of higher pressure to lower pressure; that is, to flow from the formation into the wellbore.

2. Communication with existing fractures.

The CGDP will require more wells from a single pad and this may lead to closer consolidation of well bores. Research shows that fractures created by fracking “communicate,” or connect, with existing fractures, which can eventually reach aquifers. Unfortunately, criteria for “setbacks” are applied only to the pad and to other activities and events taking place at the land surface. These applications are necessary, but are not sufficient. Though one can expect historic gas wells (and environs) to mark locations where vertical upward flow of gas and pollutants may occur, they do not mark the only locations where one can expect to find sooner or later zones of enhanced vertical permeability that eventually will reach the land surface and hence will introduce future upward flow of methane gas not only to fresh water aquifers and wetlands, but also to the atmosphere. One should also consider the effect that formation-to-formation geologic heterogeneities have on the mapping of where zones of enhanced permeability may be expected to migrate. Ditto for the locations and geometries of deep coal mines. Maryland is encouraging drillers to place well pads close together to protect the land, but will their proximity lead to unforeseen problems involving existing fractures?

Communication between induced fractures and the surface (or freshwater aquifer) is not expected to occur unless the induced fractures reach a discontinuity in the various strata that separate the Marcellus from the shallow groundwater aquifers. Some of these discontinuities are known, such as the faulting around the Accident Dome, and others are only suspected, for example, the cross-strike discontinuities (Southworth, 1986). In these cases, the discontinuities have the potential to allow migration along their joints. At this time, the exact location(s) of these faults and discontinuities are not known in Western Maryland. Therefore, the Departments plan to require as part of the Comprehensive Gas Development Plan (CGDP) that the contractor perform geological investigations to identify any discontinuities in the geologic structure throughout the entire depth and spatial extent of the CGDP planning area. This information is to be transmitted to MDE and Maryland Geological Survey.

Maryland geological experts have little concern with communication between other induced fractures within the Marcellus as any communication between those fractures does not create a pathway for upwards migration of contaminants or gas into the freshwater aquifers.

3. Seismic survey requirements.

- a. MDE scales back the seismic mapping requirements recommended by UMC ES-AL, requiring only one test per well on the pad. If we are to permit pads with up to 18 well bores, repeated fracturing of all these closely-clustered well bores & laterals could result in seismic changes. MDE should require

seismology of the area to be developed and identify the area or areas where HVHF may communicate with naturally occurring geological faults.

- b. It would be extremely beneficial to select key locations and to test at the field scale if possible for the pre-fracturing vertical permeability of the geological units of interest.
- c. Microseismic and tiltmeter data should be gathered for each well. Once again the UMCES-AL recommendations are being ignored. As work progresses and wells are repeatedly fracked additional surveys should be required to monitor subterranean conditions and prevent nasty surprises.
- d. Environmental assessments (see Marcellus Safe Drilling Initiative Study: Part 2, Section V: Item 1) should include the determination of in situ principal stresses and the mapping, specified location by specified location, of the most likely direction(s) of uncontrolled future fracturing and enhanced permeability.

Seismic surveys and other geologic investigations will occur at two different times during any unconventional gas well development. Before any production gas wells are developed, companies will be conducting geologic investigations and possibly developing exploratory wells across the landscape proposed for gas development to assess/target extraction efforts. As indicated in the response to comment 2, the broad scale three dimensional geologic investigations, which would include seismic surveys, will be required for the CGDP application in order to identify existing faults and discontinuities and guide the siting of well pads.

Once the well pad site is selected, additional geologic investigations will be made with the first pilot hole to determine the density, extent, and direction of existing fractures, voids and other necessary geologic information along its entire depth. Microseismic, tiltmeter and other analytical survey approaches may be used singly, or in combination, to provide the required data. The geologic studies at the scale of the pilot hole are required to assess the geology in the vicinity of the well site and pad. The Departments are satisfied that one geological study per well pad is sufficient to fully characterize the local geologic conditions.

The UMCES-AL study recommended that a sufficient number of micro-seismic or tiltmeter surveys be done to characterize the extent, geometry and location of Marcellus fracturing across the region; but the study did not identify how many would be necessary. Citing API Guidance Document HF1, First Edition, the UMCES-AL study also noted: "Best practice is not to employ tiltmeter surveys or microseismic on every well, rather it is most commonly used to evaluate new techniques, refine the effectiveness of fracturing in new areas or formations, and in calibrating computer models of the fracturing process." The draft best practices report recommended requiring that the operator perform a tiltmeter or microseismic survey on the first well hydraulically fractured on each pad. We believe that a microseismic or tiltmeter testing on the first well of each pad will provide the data necessary to understand the regional characteristics of the Marcellus Shale; however, MDE has the authority to require such testing on each well through the individual permit. Such a requirement might be appropriate if the first hydraulic

fracturing resulted in fractures that extended far beyond the target formation, or if the operator proposed to use a significantly different hydraulic fracturing regimen on subsequent wells. Because Maryland will require that all information collected at the site be submitted to the State, the results of any additional microseismic or tiltmeter testing will be available for use in further refining our understanding of the formation and the extent of fractures.

As detailed in the response to comment 1 above, Maryland's geological experts do not concur there will be uncontrolled fracturing due to the mechanisms described in that response.

4. Open hole logging requirements.

Safe Drilling Initiative Study: Part 2, Section VI, Section E, Item 5g. The statement is too weak. An experienced and intelligent driller has probably developed his or her own seat-of-the-pants method of estimating answers to (a) through (f) and may be good at it. If these logs are desired, they should be required.

The well permit, if issued, will contain requirements for logging the borehole. The required information, especially for items such as the depth at which any fresh water is encountered, must be reliably measured. Current Maryland regulations require the submission of these logs as a component of the well completion report.

5. Long term monitoring and protection from methane migration.

Safe Drilling Initiative Study: Part 2, Section VI, Section R (Closure and Reclamation). Responsibility and monitoring of gas and chemical contamination of aquifers should continue for three to five decades after decommissioning of the well. The burden of scientific proof and empirical corroboration lies with the gas company to demonstrate that aquifer pollution will NOT occur over the next several decades due to the gradual upward migration of permeability enhancement. Opinion or poor physics cannot be tolerated or excused. This should also be considered when setting terms of financial bonds.

The most likely route of methane migration or other contaminants to water supplies (as determined from review of case studies throughout the U.S.) is from improper well casing/cementing and/or leakage of fracking fluid waste pits, not through spread of fractures (see response to comment 1) or fracture communication with existing wells or faults. As a result, Maryland will require practices to prevent contamination from occurring and provide financial assurance/insurance coverage to address contamination events. These include:

- i. Presumptive Impacts Areas - Environment Article §14-110.1 incorporates a presumptive impact area where any contamination of a water supply within 2,500 feet of a gas well will assume gas exploration/production as the cause;*
- ii. Proposed Best Management Practices to Prevent Surface Contamination – prohibiting storage of fracking fluids in surface pits (must be in tanks with secondary containment), requiring closed loop systems for drilling and cutting, and requiring no-discharge well pads to capture any spills that may result from tanks or closed loop systems;*

- iii. *Proposed Best Management Practices to Prevent Subsurface Contamination – Requiring enhanced specifications for casing, cement cure times, and minimum compressive strength standards for cements;*
- iv. *Currently Required Permits or Practices – Mandatory well completion reports to identify extent of groundwater resources, oil and gas resources encountered during drilling, total well depth, general geology/lithology, depth of salt water, and other generalized core descriptions. Further, permits require that environmental liability insurance be maintained for 5 years after MDE has determined that a gas well has been properly plugged and the site has been reclaimed.*

The Departments’ position is that the combination of these requirements provides more than sufficient preventive and remedial measures to address contamination resulting from natural gas extraction. The Departments disagree with the comment that “gradual upward migration of permeability enhancement” is a justification for monitoring decades after a well has been decommissioned.

6. Freshwater 2000 foot vertical separation.

Safe Drilling Initiative Study: Part 2, Appendix D 1-H, states “Since the freshwater/saltwater interface has not been mapped in Maryland, the prudent approach would be to rely on the 2,000 ft criterion to provide an adequate margin of safety.” Specifying vertical depth offsets presumes that the physical characteristics of geological units remain unchanged. Assuming such a statically safe buffer zone is questionable. Changes in the vertical permeability will occur and cannot be ignored. This occurrence is dynamic because the changes migrate upward with time.

Evidence indicates that a vertical separation of the order of 2,000 feet would result in a remote risk that properly injected fluid would result in contamination of fresh groundwater. Having the default 2,000 foot vertical separation will not preclude the Department of the Environment from requiring greater vertical separation, where appropriate. Comprehensive information gathered during the environmental assessment, during pilot and exploratory well drilling, and collected from seismic tests will be used to determine if additional separation is required for an individual well to address site-specific geological factors.

7. Presence of historic gas wells.

The Environmental Working Group’s extensive study found that the horizontal fractures can extend over 2,000 feet and fracture older gas wells that may not be identified and sealed and then create a perfect path for chemical and methane migration into aquifers.

Responses to comments 1 and 6 address questions regarding upward propagation of fractures and vertical separation from aquifers. The Departments recommend a 1,320 foot setback from historic gas wells to any portion of the borehole, including laterals. Locations of known historic gas wells will be provided through the Shale Gas Development Toolbox to support the siting of well pads through the CGDP. As with other fine scale features or features that do not have comprehensive mapping

completed, such as small wetlands and headwater streams, the applicant will be required to perform site assessments to identify any unmapped historic gas wells within the setback zone.

STORMWATER MANAGEMENT

1. The well pad, according to the BMPs, would have to be surrounded by a berm designed to hold at least 2.7 inches of rain within a 24-hour period, so that spills of gasoline, oils and other hazardous chemicals wouldn't flow onto surrounding land. Maryland weather records show more than that amount of rain has fallen in 24 hours on several occasions in the past few years, including during Superstorm Sandy. Climate change guarantees more deluges, so this BMP is not sufficient to protect the land, water, human health or wildlife.

The draft report proposed that no discharge of stormwater from the pad would be allowed as long as there were any chemicals onsite, and set a minimum containment amount at 2.7 inches in a 24 hour period. Regardless of the number of inches chosen, there will inevitably be precipitation events that exceed the amount. If there were more precipitation than the containment could hold, the operator would need to remove collected stormwater for storage and proper disposal. Any discharge would be a violation of the law. Nevertheless, the Departments are persuaded that increasing the design to hold 4 inches of rain in a 24 hour period will provide additional protection and is not unreasonable. The Departments will modify the practice to require a minimum containment amount of 4 inches of rain in a 24 hour period.

2. Please modify the draft regulations to handle 4" of rainfall within a 24 hour period.

Agreed. This BMP will be modified to 4 inches.

3. BMPs to address storm water management and erosion control must be extremely comprehensive and innovative. BMPs should also be more expansive and address short- and long-term (legacy) issues.

In addition to the requirement to contain all stormwater on the pad while chemicals remain onsite, the State sediment and erosion control and stormwater management laws and regulations apply to these drilling operations. Proper reclamation of the site will address legacy issues.

4. No discharge of potentially contaminated stormwater or pollutants from the pad shall be allowed and must be enforced.

The Departments agree and the draft report reflects this requirement. Any discharge would be a violation of the law and enforced appropriately.

5. The linear nature of pipelines and the amount of clearing, grading and trenching involved makes pipelines a potential significant source of sediment pollution during the construction phase. Unfortunately, the BMP report is silent on how the Departments plan to handle stormwater runoff from pipelines, access roads, and other construction activity. We recommend that limits be placed on the length of open trench and non-stabilized soil exposed at any time. Pipelines rights of way

should be cleared, pipe laid, filled, and stabilized in segments to avoid excessive erosion. In addition, the right of way should be vegetated within an appropriate timeframe.

The State erosion and sediment control regulations would apply to these pipeline projects and specify that only 20 acres can be disturbed at any time and requires that all perimeter controls (e.g., earthen berms, sediment traps) and slopes steeper than 3:1 must be stabilized within three calendar days and all other disturbed areas within seven calendar days.

6. The Departments should make a determination whether the “hotspot” designation would provide better stormwater management protection than what is otherwise contemplated by the BMP Report. Hydraulic fracturing operations should be treated the same as similar heavy industrial activity.

In the judgment of the Departments, designation of the pad as a “hotspot” would not afford any better protection than the recommended BMPs. The BMPs could be incorporated into the well permit. Because the well permit must be renewed periodically and stay in effect until the well is properly abandoned, this will provide protection during the lifetime of the well.

7. The requirement to capture, store and transport all storm water can result in a large increase in truck traffic to haul the storm water from the entire pad. Capturing and storing only that water which could potentially be contaminated would be an adequate approach to meet the environmental safeguards sought without unnecessarily increasing truck traffic. Establishing a clearer definition of what constitutes a “drilling pad” could also be helpful. Potential contamination sources would be the drilling rig and associated equipment, excluding areas occupied by temporary housing, parking lots, etc.

In establishing the BMPs for stormwater, the Departments made the assumption that all stormwater that collects on the pad could potentially be contaminated by contact with equipment, fuel or chemicals. If the operator collected stormwater in aboveground tanks, it could be used for hydraulic fracturing.

The Departments will define the “drilling pad” to include that area where drill rigs, pumps, engines, generators, mixers and similar equipment, fuel, pipes and chemicals are located. The definition will exclude temporary housing and employee parking lots.

8. Require gas companies to complete Storm Water Pollution Prevention Plans that severely limit toxic run off and erosion.

This was included in the draft report.

9. Require gas companies to complete Storm Water Pollution Prevention Plans that completely contain toxic run off and erosion. No "mitigation" or "minimization" weasel-wording.

See above.

STRINGENCY OF THE PROPOSED BEST PRACTICES

1. The recommended best practices are unjustified, too stringent and too onerous.
 - a. The Governor's call for a "Gold Standard" has Maryland proposing the strictest set of drilling requirements in the United States. But in its effort to propose the strongest standards, the State has drafted its own Best Practices, a number of which are not required by any other state or a voluntary consensus Industry standard and that, if adopted, may not allow for reasonable development. While learning from other states or Industry experiences makes sense, creating an untested Best Practice in a vacuum does not.
 - b. Maryland should leverage the best practices from other states deeply involved in fracking.
 - c. These are excessive requirements that are more stringent than those in neighboring states:
 - i. High financial assurance requirements, including a periodic updating of closure cost estimates.
 - ii. Closed-loop drilling
 - iii. Zero discharge pads
 - iv. Prohibition of impoundments for anything except fresh water
 - v. On-site management of flowback and produced water
 - vi. Mandatory chemical disclosure that does not protect proprietary trade secret information.
 - d. The Practices recommendation was undertaken pursuant to an Executive Order directing a study to include recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland. A popular definition of a best practice defines it as the "best way to do something; the most effective or efficient method of achieving an objective or completing a task." [Bing Dictionary]. By focusing primarily on the environmental science report and largely ignoring industry recommendations for the most efficient and effective means of production, the Practices recommendations fail to fulfill the stated purposes.
 - e. The intention of the BMPs should be to protect human and environmental health, however, the research has not been done to provide a scientific basis for these practices.
 - f. Our biggest concern lies with the process of the Comprehensive Gas Development Plan. With only approximately 1 percent of the shale play lying in our area and Dr. Eshleman's report recommending that this type of plan be voluntary, the proposed regulations are too time consuming and expensive compared to our neighboring states. In my view, this discourages the entry of multiple companies into the Maryland fields and

at this point has completely run the gas companies “out of town” so far as considering leases or development of wells. It may be an unintentional consequence, but this limits competition and works to the disadvantage of all. I do not quite understand how the effort to develop an oversight process turned into a focus of creating a “gold standard” that makes Maryland regulations more stringent than any other state in the nation.

Governor O’Malley’s Executive Order establishing the Marcellus Shale Safe Drilling Initiative acknowledged that there were potential benefits and risks of damage from gas extraction. The Departments have attempted to identify feasible practices that are likely to protect public health, safety, the environment and natural resources if the Administration chooses to move forward with Marcellus Shale drilling. The suggestion that reports released thus far have been done in a vacuum is not the case. The State considered the regulations of other states and industry consensus standards. The draft report recommended that applicants, in preparing the plan for the individual well, “consider API Standards and Guidance Documents, and, if the plan fails to follow a normative element of a relevant API standard, the plan must explain why and demonstrate that the plan is at least as protective as the normative element.” In addition, the Departments have considered the new laws and regulations that have been enacted in other states. Some of the proposed best practices that seemed innovative are now the law in these other states.

The financial assurance requirements were recommended by the Departments and the Advisory Commission and passed by the Maryland legislature in 2013. The periodic updating of closure cost estimates is necessary because there has been so little experience with the actual costs of closing Marcellus shale wells. Closed-loop drilling has become common in Marcellus shale states, as have improved management of flowback and produced water. The draft report included the recommendation that at least 90 percent of the flowback and produced water be recycled on the pad where it is generated, but allows for alternative management if this is not practicable. Zero discharge pads and prohibiting the use of impoundments for wastes and wastewater offer an increased level of protection from contamination of ground water and surface water. The chemical disclosure recommendation was designed to protect trade secrets while giving those with a legitimate need access to chemical information.

The definition of best practices in the Executive Order is “methods and techniques that have consistently shown results superior to those achieved by other means, and which are used as benchmarks.” In the context of the Executive Order, it is clear that the desired result is not to identify “the most efficient and effective means of production” but rather to determine what practices could reduce risks to reasonable levels. At the same time, the Departments did consider the practical feasibility of the recommended practices. The best available science was used as a basis for the practices that are designed to protect human and environmental health.

The mission of the Maryland Department of the Environment is to protect and restore the quality of Maryland’s air, water, and land resources, while fostering smart growth, economic development, healthy and safe communities, and quality environmental education for the benefit of the environment, public health, and future

generations. The Department of Natural Resources leads Maryland in securing a sustainable future for our environment, society, and economy by preserving, protecting, restoring, and enhancing the State's natural resources. The intent of the recommended best practices is to support both missions.

2. The recommended practices are too costly. As we continue the effort to define the balance between the rights of property owners and the protection of the environment, the accountability of state officials to oversee the regulatory side of the equation with a timely and balanced approach is a major concern. Of all of the studies that have been ordered, I don't believe I have seen a calculation of what the cost of existing regulations for any kind of development already on the books amounts to with the gas industry, much less the cost of all the newly proposed regulations that are being proposed (such as the CGDP). It is a simplification to just say that these are "gas company costs." Every cent eventually leads to a reduction to the property owner, which in turn is a reduction to our communities and the state in taxes that will be paid.

Most of the recommended best practices have been adopted by one or more states or are already used by the industry to prevent environmental and public health impacts resulting from substandard practices. Comprehensive Gas Development Planning at a landscape level has been used on a voluntary basis elsewhere and is one of the few practices that can address cumulative impacts of gas development.

3. The recommended best practices will unreasonably delay drilling in Maryland.
 - a. The net result of these recommendations will reduce any interest in shale gas production in Maryland because they are so stringent and time-consuming, especially the CGDP and the two years of baseline monitoring. Unless the Commission establishes a shorter and more realistic time frame, drilling will be delayed while we are seeking to expand upon economic opportunities and diversity through job and industry growth.
 - b. Although the environmental study suggested voluntary plans, the Practices require a mandatory plan, thereby adding an additional, time consuming and expensive planning requirement to review locations of all contemplated facilities intended by a prospective driller who may not yet even have obtained the leases, options, rights-of-way and other property rights. Besides the huge preparation difficulties, this requirement also lacks defined standards of review and allows approval/disapproval virtually at the discretion of the "State" (presumably meaning MDE). In addition, the process of plan reviews is to include a complex process of State review, local government review, stakeholder comments and public comments following a public meeting. Then, the approval/disapproval decision would probably be appealable to a court in a de novo proceeding. Although there are some benefits to such a plan in coordination and siting, these can be accomplished by a regulation in regard to pooling and siting of facilities, without the addition of an entire pre-development level of planning reviews, hearings and potential litigation.

- c. As an overall view of the recommendations from the document, this appears to be geared toward requiring a great deal of initial reporting from the operator to identify all of the future plans for drilling and production in Maryland prior to any exploration drilling. The processes outlined require considerable reliance on state agencies developing protocols, plans, and toolboxes that currently do not exist. Coupled with requirements for extensive multiple-year testing prior to the initiation of drilling, if an operator worked diligently to drill an exploratory well in Maryland today, these draft requirements and recommendations would put the well spud date at minimum of five to six years into the future, assuming the state develops the maps and protocols within one year of approval of the final report, a goal that would prove challenging to achieve. Our organization believes that a realistic and shorter time frame should be considered for the combined CGDP and baseline activities (perhaps 12 months or less) which would allow for exploratory wells to be drilled earlier in the process to help provide more accurate and detailed information necessary for the development of the CGDP.
- d. An industry group estimates that, given the recommended processes, a well operator will have to dedicate four years of resources and expense before obtaining any information on the viability of production from the Marcellus formations in Maryland. Given the choice of proceeding through Maryland's cumbersome processes or dedicating resources elsewhere, well operators will almost certainly choose to operate in other states, further decreasing Maryland's economic competitiveness in this arena. A more realistic time frame should be considered.
- e. After reviewing the content of the draft report I conclude that it will be 2020 or later before any drilling for natural gas can occur if all of the recommendations are accepted to create the "GOLD STANDARD" in Maryland. Permits are being processed and drilling is taking place in our neighboring states. The process to get a drilling permit in our neighboring states and other states in the Union takes weeks or months, certainly less than a year.
- f. We have waited long enough. We see drilling all around Garrett County and we are not allowed to take advantage of it. Reasonable controls are appropriate. The proposed requirements are too restrictive and designed to slow or stop drilling. PA WV seems to do ok. Let's not reinvent the wheel. Follow their experience and parallel their regulation.
- g. No justification is identified for the imposition of predevelopment data collection, which will be lengthy and expensive data collection and reporting requirement. The effect is to add an additional two (2) years on top of the potential two to four year period required to obtain an approved Comprehensive Plan before application for a specific drilling permit. Because an eventual drilling permit would be subject a review/appeal process, there is the likelihood that the recommended Practices would involve a five to seven year span before drilling could occur. Such

Practices, in effect, would prolong the de facto moratorium on shale gas drilling in Maryland.

- h. We believe that some of the proposed mandates and testing requirements including the CGDP are some of the most stringent regulations in the Country but are also very costly and time consuming, while offering minimal environmental protection. These recommendations rely upon state protocols and plans that have yet to be established; or assessed for practicality in real time applications. Therefore, we urge the commission to seek shorter and more realistic timeframes to be considered for the CGDP and allow the exploration for shale gas to be done earlier in the process to provide for more accurate and detailed information for the approval of the final CGDP. Please remember that we are competing against other states for this economic activity while protecting our natural resources.
- i. There is a major risk that the numerous additional requirements suggested in the draft Practices will have the effect of extending a de facto moratorium on shale gas development in Maryland. We strongly encourage rethinking and revision of the proposed Practices, to reduce the burden of additional requirements wherever possible while retaining reasonable protections for the environment.
- j. We believe they go above-and-beyond what the Governor has called a "Gold Standard" for drilling for natural gas. The permitting proposals would add an increase in cost (upfront in particular), and the time consuming process would make it extremely unlikely that any company would be willing to meet all of these requirements, especially under the present market conditions.

The Departments have tried to structure the best practices and the permitting process in a way that balances the interests of the stakeholders. The CGDP is a broad-brush, landscape level plan that, according to industry sources, is not very different from the planning that industry does now. The Departments do not anticipate that this will consume very much time. As proposed in the draft report, the CGDP review process could be completed in less than six months. The two year monitoring period can begin as soon as the CGDP is approved. For groundwater and especially for surface water, the year-to-year variability can be large. Two years is a reasonable compromise given inherent seasonal variability in environmental data.

Some elements of the Toolbox already exist, and more can be added in short order. The Departments will be able to pull some protocols "off the shelf" and develop the remaining protocols in a timely fashion.

The Departments have reviewed the regulations of other states so there was no need to reinvent the wheel. Pennsylvania and West Virginia allowed drilling in the Marcellus shale before updating their regulatory programs. Maryland hopes to learn from their experiences. We are mindful of the competition that exists among states, but Maryland wishes to avoid the damage that has occurred in some states because the laws and regulations were inadequate or poorly enforced.

It is also important to remember that other key economic engines in this region (tourism and outdoor recreation) rely on the relatively rural and undeveloped landscape. Allowing potentially large-scale industrial activity to proceed without careful planning and incorporating lessons learned from other states jeopardizes the viability and profitability of these other key industries. In the Departments' view all of the planning and best management practices proposed strike a fair balance between the multiple stakeholders whose livelihoods depend on the natural resources of the region.

4. The regulations deprive people of their property rights or violate the Constitution.
 - a. I am in favor of being allowed to drill for my gas and to take it to market. As it stands now, my State government is blocking me from selling property that I bought with hard earned dollars. I am extremely disturbed by this action. I can still sell the timber from my land if I so choose, or even a big rock, if someone wants to buy it. But not MY gas. Certain people in our state are so concerned about drilling for this gas that it has been, for all practical purposes, stopped / blocked.
 - b. A de facto taking occurs when government laws, regulations, or restrictions in fact take your property because you can't use it. You've been deprived of your property rights without being paid. My first question is: Has or will the committee consider the cost to the State of Maryland if the Courts were to determine that because of all the regulations and restrictions imposed on natural gas drilling in Maryland, the result is a de facto taking of property rights. (Natural Gas) Maryland seems intent on setting an extremely high bar for the natural gas industry and setting standards that are tougher than in any other state. Eminent Domain, the governments taking of property, is ultimately a federal constitutional question.
 - c. Can the State of Maryland under the Federal Constitution set a higher standard for drilling than all the other states where natural gas development is taking place? If the people of Garrett County with natural gas rights had those same rights just across the line in West Virginia or Pennsylvania, they could be worth a fortune. In Maryland those rights are worth nothing, and they may never be worthy anything. How constitutional is that?
 - d. I believe the MDE/DNR recommendations are more of a political statement than based on good science, are excessive and unnecessarily cause gas rights owners in Maryland extreme barriers to realizing value from our land and minerals that we are granted by the Constitution of the United States. These proposals are, once again, an attempt by those who reside in areas where these natural resources do not exist, to impose their preferences and beliefs on those of us who rightfully own these resources.

The question of whether a temporary moratorium or regulatory restrictions on development constitute a taking without just compensation is a complex one and beyond the scope of this response to comments. In general, a temporary moratorium

for the purpose of developing comprehensive regulations is not a taking. Similarly, regulatory restrictions that do not deprive a property owner of all reasonable use of his property do not amount to an unconstitutional taking. The regulatory program being developed under the Marcellus Shale Safe Drilling Initiative is not intended to prevent gas development if it can be done without unreasonable risk.

States can and do enact laws and regulations that differ from each other without violating the Constitution. The proposed best practices are based on the best science available, not on political considerations.

5. The recommended best practices are unreasonably harsh compared to other industries and risks.
 - a. How do the risks and regulation of drilling for gas compare to other things that the government either allows or does little to stop?
 - i. The construction of windmills on ridgetops, with damage from the site pads, access roads, and power line rights of way.
 - ii. The tons of salt used on highways each year, that damage water wells, water sources, trout streams and forests.
 - iii. The wooly adelgid and red rust fungus are destroying out hemlocks, which will damage trout streams.
 - b. The report portrays a very negative viewpoint toward the natural gas industry. If every new applicant for permits to engage in any new industrial development in Maryland was required to meet every stringent requirement outlined in this report, there would undoubtedly be a complete lack of interest by any person, firm or company to do business in Maryland.
 - c. We consider the CGDP requirement to be above and beyond the standard set for any other industries in Maryland and maintain that it will impair the economic viability of the gas play. Therefore, we would like the department to withdraw or completely revise the regulations regarding the CGDP. We also feel that it should be voluntary, not mandatory, with incentives to encourage companies to comply.
 - d. The magnitude of the effort to prevent drilling using the technique called horizontal drilling and hydraulic fracturing until the report is completed and recommendations adopted leads one to believe that there is a presumption that this activity is much more destructive than any other industrial activity that takes place in Maryland. No other industrial activity in Maryland has ever been singled out for this degree of scrutiny. There seems to be very little concern about the clear message that Maryland is sending to those who would desire to do business in Maryland. The message currently is simply that they are not welcome in this state. If all of the recommendations of this study and report are implemented in law, regulation, or permit conditions it is highly unlikely that any drilling will occur in Maryland (at least in the foreseeable future). If it is the intent of

those that commissioned the study to prevent the development of natural gas in Maryland, then their mission has truly been accomplished.

- e. For certain common activities, these proposed Best Practices would treat the drilling industry differently than everyone else without any justification. One example is the proposal for storm water management. We strongly question with the present natural gas market, the sizable acreage of leases not being renewed in Western Maryland, and these overly stringent requirements whether there will be any significant development of the Marcellus Shale in Maryland before 2020. This proposal could result in a continuation of the de-facto drilling moratorium. The draft BMPs and the potential "Gold Standard" for development only mean something if they are balanced enough to allow drilling in Western Maryland while offering sufficient protections to the environment and the citizens of Maryland.

The Departments do not agree that the government fails to protect against the risks posed by wind turbines, road salt and the wooly adelgid.

Wind turbines and shale gas development present some of the same risks of loss of habitat and forest fragmentation. Wind turbines are permitted by the Maryland Public Service Commission (PSC) by issuance of a Certificate of Public Convenience and Necessity (CPCN). (Certain projects, if they do not exceed 70 megawatts, may be exempt from the CPCN.) Other State agencies provide information and recommendations to the PSC and there is a public process. Before a final decision on the CPCN, the PSC must consider the effect of the generating station on, among other things, air and water pollution and esthetics. The CPCN may impose conditions on the project, such as an endangered species mitigation plan.

Road salt can cause adverse effects on water and land resources. Under § 8-602.1 of the Transportation Article of the Maryland Code, adopted in 2010, MDE and SHA are required to develop and annually update a Statewide Salt Management Plan to minimize the adverse environmental impacts of road salt runoff. For counties and municipalities it is expected that such plans be developed at the local level.

Maryland Department of Agriculture Forest Pest Specialists monitor the health and vitality of forests in the region on a regular basis. Red Rust Fungus is not thought to occur in Garrett County, but potential sightings should be reported to the MDA Forest Pest Program. This fungus is not a threat to hemlock trees. It has been found on growing stock in nurseries, but outbreaks in a natural setting are uncommon. Additionally, the Maryland Department of Agriculture has a very active program for suppression of Hemlock Wooly Adelgid, which includes insecticidal application and biological control. Insecticidal application is one tree at a time with either soil injection or trunk injection. This is extremely slow, but the Adelgid have not been widespread in Garrett County until recently. Keeping forest along streams and rivers is a priority on state lands, and set-backs, best management guidelines, and other zoning protect privately owned forest along streams during logging and land clearing operations.

Gas production from horizontal drilling and hydraulic fracturing differs in scope and magnitude from the conventional gas drilling that occurred in Maryland in the twentieth century. It is also different from ordinary industrial activity in that it can occur in remote rural settings and residential areas. It is reasonable to establish regulatory standards before allowing it to occur. The best practices report considers the risks posed by horizontal drilling and hydraulic fracturing. It does not assume that the industry is more “destructive” than other industries.

The Departments believe that the stormwater management requirements are not unduly stringent. Many facilities in Maryland are required to obtain a general permit for the discharge of stormwater associated with industrial activity unless they can make a “No Exposure Certification.” The oil and gas industry is exempt from this permit requirement, but Maryland can include controls on stormwater under its gas well permit.

6. The recommended best practices should be strengthened and too much deference was paid to industry’s interests.
 - a. All permits should have a requirement that if more stringent regulations are passed, the new regulations must be followed. Operations must be shut down until the company can comply.
 - b. Regarding the constraint analysis, it is inappropriate for Maryland’s agencies to develop regulations with the intention of maximizing industry’s ability to recover resources under our communities.

The recommendations of BMPs in the report do not preclude the use or introduction of new and innovative technologies. In some circumstances, new regulations are immediately applicable or can be included when permits are renewed, a process that occurs every five years. New regulations may also apply when a company replaces or retrofits equipment. In other instances, particularly where complying with the new regulations would require a company to retire facilities that have considerable useful life remaining, it would be unfair to require immediate compliance. Lastly, regulated businesses are usually given some time to comply with new regulations and are not required to cease operations entirely.

The constraint analysis was performed to demonstrate that the setback requirements and restrictions on location did not prevent the industry from accessing most of the natural gas in the Marcellus shale in Maryland. It was not used to set the restrictions or setback distances or to maximize industry’s ability to recover gas.

SURFACE IMPACTS AND SETBACKS

1. The activity will last a long time and will be disruptive.
 - a. Fracking is an industrial activity best confined to areas zoned for industry, and the state should indicate so in the BMPs and eventual regulations.
 - b. Pads may be permanent or nearly permanent fixtures if the wells are subject to enhanced gas recovery and then for geologic sequestration of CO₂.

- c. The noise, truck traffic and lights 24/7 are not only for thirty days as industry would like the public to believe. Some well pads may have more than one well, as many as 6-10, drilled in sequence. Companies may continue with these wells for years. Completion may not happen in our life-time.
- d. In neighboring states, we have seen severe disruption to agriculture, vegetation and to the topography.
- e. The wells and wastewater sites desecrate beautiful natural landscapes and deprive local flora and fauna of habitat.
- f. How much buffer is enough to protect the water, air, and quality of life for those living near such an industrial zone? Keep in mind that Garrett County is currently a rural area of farms and forests. How will those who live near these areas be compensated for these impacts? If compelled to move due to the insults associated with this industrial zone who would buy their homes and land? Remember, these are most likely people who have not signed gas leases and who will not be receiving any royalties.

Counties and towns, not the State, have authority to zone. Under current law, MDE must deny a permit if the applicant has failed to receive applicable permits or approvals for the operation from all State and local regulatory units responsible for, among other things, zoning. Current State regulations require the applicant to produce written approval by the local zoning authority that all local planning and zoning requirements have been met.

Pads may be permanent or nearly permanent, but the permanent pad will have a lesser impact than a pad on which drilling and hydraulic fracturing is occurring. Reclamation requirements would serve to reduce the size of the pad to the area needed for gas production and well maintenance.

The Departments acknowledge that activity may occur on a single pad for several consecutive months and may recur. The best practices are designed to limit the impact of the activities under either circumstance. The Departments propose to limit the hours of truck traffic to and from the well pad and place restrictions on the initiation of drilling, fracturing or other activities in order to minimize impacts during times of peak outdoor recreation or sensitive wildlife migratory or mating seasons.

The best practices are designed to avoid severe disruption to agriculture, habitat, flora and fauna. In addition to the CGDP, which will require consideration of locations that avoid these impacts, there are specific protections against the introduction of invasive species, light pollution, and noise pollution. The CGDP will also reduce the impact on landscapes.

Buffers are one way to reduce or eliminate the impact of gas exploration and production on neighboring properties and residents. Other best practices address ways to reduce the sources and causes of those impacts and ensure that the site is appropriately restored. If companies undertaking gas exploration or production activities intentionally or negligently cause contamination, they would be liable for

damages. The existing law specifically addresses liability for damage to water sources within 2500 feet of a gas well. Other provisions require insurance so that funds will be available for cleanup or to pay damages.

2. There should be a limit on the total amount of land that can be disturbed.
 - a. The Eshleman report recommended that gas drilling activities be limited to only 1-2 percent of Maryland's land surface. This should be applied throughout the State because gas-bearing shales are present in other places in Maryland.
 - b. Mention is made "Avoid surface development beyond 2 percent of the watershed area in high value watersheds. " There is no "should" or "must" associated with the stated threshold. MAC believes that a 2 percent surface development on the Savage River watershed would have a huge impact not only to the environment and streams that brook trout inhabit but also to the natural setting and recreational experience that the watershed provides.
 - c. The total disturbance limit to 2 percent on high value acreage should be extended to all extraction zones. A different limit might be appropriate but no limit is not reasonable.
 - d. The state will not require that multiple companies submit comprehensive drilling plans together; rather, it will "encourage" them to work together on drawing up their plans. Asking the gas industry to voluntarily work together and share information about its drilling sites does nothing to guarantee that the public's interest is taken into account during planning.

The recommendation of the UMCES-AL report that activities be limited to 1 to 2 percent of Maryland's land surface has been widely misinterpreted. The actual recommendation was that "Cumulative surface development (including all well pads, access roads, public roads, etc.) could be maintained at less than 2 percent of the watershed area in high-value watersheds." UMCES-AL report at 6-14. The State has limited land use authority; the authority to enact zoning, subdivision, and other land use restrictions lies with the counties and municipalities. Nevertheless, the Departments adopt this recommendation as a planning principle to be followed in the CGDP and to be used as a performance measure. The recommendation was based on empirical evidence that aquatic habitat and aquatic diversity become degraded by stormwater runoff well before the percentage of impervious surface reaches 10 percent and that brook trout are almost never found in watersheds where impervious surface exceeded 4 percent. The loss of some species, particularly stream salamanders, can occur in watersheds with only 0.3 percent impervious surface. The UMCES-AL research showed a relationship between the amount of impervious surface in a watershed and degradation of the stream. In order to provide an adequate margin of safety, UMCES recommended a 2 percent surface development threshold which they note can be achieved through the sensible application of best practices and comprehensive planning. The UMCES research relied in part on studies and analysis provided by the Department of Natural Resources:

- *Fact Sheet: Impacts of Impervious Land Cover on Maryland Streams*³⁶
- *S.A. Stranko et al. 2008. Brook Trout Declines with Land Cover and Temperature Changes in Maryland. North American Journal of Fisheries Management 28: 1223-1232.*³⁷

The State and local governments take steps to protect all aquatic habitats from the effect of stormwater runoff, including requiring stormwater management. The Comprehensive Gas Development Plan will help limit the amount of surface disturbance and direct it away from sensitive areas. The CGDP is mandatory for a company, but it is not possible to compel companies to develop joint plans.

3. Some lands need more protection.

- In general, we recommend inclusion---in the table and/or the accompanying text---of the rationale for the specified setbacks. Some appear arbitrary.
- Proposed setbacks allow drilling 600 feet from “irreplaceable natural areas” and “wildlands” and a mere 300 feet from a stream, river, spring, wetland, pond, reservoir and 100-year floodplain. Drilling so close to these fragile areas is unacceptable.
- For aquatic habitat (riparian), the UMCES-AL Report cited recommended varying setbacks based on biodiversity. The lowest setback was 330 feet and the greatest was 1,240 feet (Table 5-2 and page 6-4). Why are the Departments recommending a setback of 300 feet? Does the setback provide adequate protection? Usually riparian areas are protected by vegetated buffers. Will these buffer areas be factored into the setback calculation?
- Setbacks are distances in the BP Report from the well bore or well pad and as mentioned in the setback table from the disturbed area to water supplies or other important natural resources that need to be protected from contamination, damage, view, or other object in need of separation. The initial distances for state parks, scenic and wild rivers and for special conservation areas (e.g., irreplaceable natural areas, wildlands) are grossly inadequate and require reevaluation after a formal risk analysis has been completed.
- Include wildlands and all public lands under III.E.2.
- Ecologically sensitive areas and irreplaceable habitats should be protected from the adverse impacts of all aspects of gas and oil development and supply, including drilling, pipelines, associated infrastructure and sand mining; the high value habitats in Important Bird Areas should be protected from industry activities.
- The setbacks presented for the protection of scenic and wild rivers, special conservation areas, is determined without consideration of methane

³⁶ www.dnr.state.md.us/streams/pdfs/ImperviousFactSheet.pdf

³⁷ http://clear.uconn.edu/projects/TMDL/library/papers/stranko_et_al_2008.pdf

migration via rock fractures well outside the limits collected from other states and offered as "Best Practices". The suggestion that setbacks may be expanded on a case by case basis merely suggests that the issue has not been seriously considered.

- h. A setback of 300 feet from aquatic habitat (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and 100 year floodplains) is not sufficient protection for waterways used by boaters and fishermen. Drill pads should not be visible from a waterway or body of water; disrupting river/reservoir use would have serious economic consequences for tourism.
- i. The Departments must use existing statute provisions (Md. Env. Code, Section 14-108) to protect special and unique areas.
- j. No CGDP plan or permits should be issued for fracking on public land.
- k. A 300-foot setback on a body of water used by wildlife and for human recreation is so small that the drill site would be visible from the waterway; disrupting water use would have serious economic consequences for the tourism sector, in addition to threatening wildlife, especially endangered species.
- l. As a watershed organization we know there are 18 mineral leases in the DCL watershed. We are concerned that the setbacks for drilling are insufficient to provide the protections needed within our watershed and in the County.
- m. A 300-foot setback for aquatic habitat, (all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs and 100-year floodplains) is totally inadequate as are a 600-foot setback for special conservation areas (irreplaceable natural areas and wildlands) and 300 feet for all cultural and historical sites, state and federal parks, trails, wildlife management areas, scenic and wild rivers and scenic byways. Surface disturbance in areas with sensitive resources should be limited to 3,000 feet.
- n. 300 feet as a setback from historic sites would certainly destroy any historical site or park. The industrial nature of a drilling operation is in direct conflict with the goal of preserving cultural and historic or scenic and wild byways. These unique resources need protection of at least 2000 feet if not much further.
- o. There should be a setback from land on which MALPF holds an easement.
- p. The setbacks from streams and rivers should be more than 300 feet – maybe 1,000 feet from the drilling pad.
- q. I live adjacent to a river canyon and can show you how and where a simple tire track off the side of a road, can become a channel through which rain finds its way to an underground spring or drainage field that eventually finds its way to a creek and a river. I consider the 300 foot

setback from waterways to be highly problematic and, I have to believe, an arbitrary and uninformed criterion for ecosystem protection.

- r. Greater setbacks for critical facilities such as hospitals, police and fire stations should be considered. A hospital would be hard to evacuate if needed. Police and fire stations will need to remain operable if there are problems. Are there existing setback requirements from a cemetery?

The setback distances were established using the best available science and information. For environmental setbacks, the habitat needs for sensitive species were a key consideration. Common sense suggests that wider buffers should be more protective of sensitive natural resource areas, although at some point the benefits of buffer width extension may not increase further as buffer width increases. As an example, the minimum buffer width recommendations for “Irreplaceable Natural Areas” are based in part upon ecological factors, notably the optimal minimum buffer width for forest interior-dwelling species (FIDS) and the minimum buffer for forest canopy disturbance relating to the incursion of weeds and edge species.

The UMCES-AL report notes the results of studies of setbacks, but recommended “minimum setbacks of 300 ft from floodplains, wetlands, seeps, vernal pools, streams, or other surface water bodies.” Page 5-6. The Departments initially accepted this recommendation. Based on the comments and additional research, the setback from all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and 100 year floodplains has been increased from 300 feet to 450 feet and addresses both water quality and biodiversity protection.

In order to fine tune setbacks for lands important for providing outdoor recreational uses, the Department of Natural Resources conducted a mapping workshop to identify recreational areas that are intensively used in the Marcellus Shale areas of Maryland. The locations of these areas will be mapped and included in the toolbox to guide the preparation of a CGDP that will avoid conflicts with public use. Setbacks may be expanded on a case by case basis, using, in part, the information collected through the DNR participatory GIS workshops.

Although drill rigs may be visible to boaters and fishermen even with the setback distance of 450 feet; completed well pads will not be as visually intrusive. Visual mitigation measures, if appropriate, can be imposed suitable to the season and activity. The long term visual impact of completed pads should not have a significant impact on the tourism economy.

Wildlands and public lands will be mapped in the shale gas development toolbox. The best practices are designed to protect ecologically sensitive areas and irreplaceable habitat. The combination of protective setbacks and good planning through the CGDP will also protect other high value resources, such as Important Bird Areas (IBAs) because many of these areas are co-occurring. The CGDP will help insure that the pad, wells and infrastructure avoid these areas. Sand mining is not addressed through these best practices recommendations because it falls under a separate permit program.

Methane migration is addressed through best practices and methane leaks will be addressed through a leak detection and repair program.

Section 14-107 of the Environment Article of the Maryland Code establishes a blanket prohibition against drilling for oil or gas in the waters of the Chesapeake Bay, any of its tributaries, or in the Chesapeake Bay Critical Area. In contrast, Section 14-108 deals with individual permit applications and requires MDE to deny a permit if it determines that proposed drilling or well operation poses a substantial threat to public safety or a risk of significant adverse environmental impact to (i) The Chesapeake Bay; (ii) The Chesapeake Bay Critical Area; (iii) Tidal or nontidal wetlands; (iv) Endangered or threatened species, species in need of conservation, or the habitat of any of them; (v) Historic properties under § 5A-326 of the State Finance and Procurement Article; (vi) Populated areas; (vii) Freshwater, estuarine, or marine fisheries; or (viii) Other significant natural resources. It also requires the Department of the Environment to deny a permit if the proposed 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 in existence at the time of the application for the permit; or if the operation will have a significant adverse effect on the uses of a publicly owned park, forest, or recreation area in existence at the time of the application for the permit. Section 14-108 required consideration of the individual permit application, and will be used as appropriate to protect these areas from substantial threats to public safety or a risk of significant environmental harm.

As noted above, the recommended 300 foot setback from surface water has been increased to 450 feet based on both water quality and biodiversity protection. A blanket set back of 3,000 feet cannot be justified. The basis for requiring a setback from MALPF-eased land is unclear. Setbacks are applied to public lands to minimize the potential public use and recreational conflicts. These concerns are not applicable to privately owned eased lands that are not supporting a public recreational use. The presence of wildlife and the impact on public and private property, historic areas and recreational areas can and will be considered during review of the CGDP and the individual well application.

The setbacks for occupied buildings should be adequate for hospitals, police and fire stations. In addition, as noted above, Section 14-108 of the Environmental Article of the Maryland Code also requires the Department of the Environment to deny a permit if the proposed 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 in existence at the time of the application for the permit. There are no setback requirements specific to cemeteries.

4. Public and private wells should be protected by equal setbacks.
 - a. Under the proposed BMPs, the drill rig can be as close as 1,000 feet from an occupied building (house, school, medical office, store), 1,000 feet from a private well and 2,000 from public groundwater wells or surface

water intakes and reservoirs. We do not think private wells and public groundwater wells should be treated differently.

- b. It is appalling and shameful to propose different setback standards for municipal waters and for private wells.
- c. The report proposes a setback of 2,000 feet for public water supplies but only 1,000 feet for private wells. In essence, you are saying that safety and health is not important for the few or if only a few families are adversely affected.
- d. The 2000' public drinking water supply setback should also apply to public drinking water tributary streams and impoundment borders.

The Departments are concerned about the health and safety of all Marylanders. There are distinctions between public and private wells, however, that justify different setbacks. Public wells generally draw water from a larger area than private wells, making a larger distance appropriate. The Departments propose, however, to modify the setbacks for drinking water protection as follows: a well pad cannot be located

- a. *Within 1,000 feet of a wellhead protection area or a source water assessment area for a Public Water System³⁸ (PWS) for which a Source Water Protection Area³⁹ (SWPA) has been delineated. [Note that a similar setback is already in effect for wellhead protection areas. COMAR 26.19.01.09G]*
- b. *Within 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).]*
- c. *Within 2,000 feet of a private drinking water well; except that the well pad may be located between 1,000 and 2,000 feet of a private drinking water well if the applicant demonstrates through a hydrogeologic study that the proposed well pad is not upgradient of the private drinking water well and the owner of the private drinking water well agrees.*
- d. *Within 450 feet of any other stream, river, seep, spring, lake, pond, or reservoir from which drinking water is drawn.*
- e. *Within the watersheds of any of the following reservoirs:*
 - i. *Broadford Lake*
 - ii. *Piney Reservoir*

³⁸ A public water system is a system for the provision to the public of water for human consumption through pipes or other constructed conveyances, if such system has at least fifteen service connections or regularly serves at least twenty-five individuals. There are three types of public water systems: community water systems, nontransient noncommunity water systems and transient noncommunity water systems.

³⁹ A Source Water Protection Area (SWPA) means an area delineated through Maryland's source water assessment program for the protection of a groundwater source (wellhead protection area) or a surface water source. For public water systems that withdraw less than 10,000 gpd from fractured rock aquifers using, if a specific SWPA has not been delineated, the boundary shall be a fixed radius of 1000 feet around the water well(s).

iii. *Savage Reservoir*

The Departments continue to believe that a setback of 2,000 feet for public drinking water system wells is appropriate. A 1,000 foot setback for private drinking water wells is reasonably protective against surface spills if the proposed well pad is not upgradient of the private drinking water well and the owner of the private drinking water well agrees; otherwise, the setback from private drinking water shall be 2,000 feet.

Based on further consideration, the Departments have decided to establish a setback specifically for springs that are the source of domestic drinking water to the residents of the property on which the spring is located. The setback, measured from spring to the edge of the well pad, shall extend to all lands at an elevation equal to or greater than the spring discharge elevation, but not to exceed 2,500 feet unless a delineation of the recharge area prepared by a registered geologist, with a report and data supporting an alternate area, is submitted to the Department and the Department approves an alternative area.

5. Setbacks of one to five kilometers should be adopted.
 - a. We recommend that all setbacks—whether from streams, springs, rivers, wetlands, ponds, scenic byways, reservoirs, schools, homes or shops—be at least 3,500 feet. (If the health study shows that even greater setbacks are needed to protect residents and wildlife from air pollution, then these setbacks will have to be revisited.) Proposed New York regulations call for a buffer of 4,000 feet from “unfiltered surface drinking-water-supply watersheds.” We recommend the state consider that distance as well. A Duke University Study found that 82 percent of drinking water wells monitored within a 5 kilometer radius of drill bore were likely to contain stray methane. Of those, the wells within one kilometer (3280 feet) were 6 times more likely to contain stray methane. (report) University of Texas Arlington has released a report establishing a 3 kilometer distance of impact between drill pads and drinking water wells. This study was similar to the Duke study that measured methane concentrations in drinking water. The Texas study shows significant risk to drinking water wells within 3 kilometers, not of methane contamination, but of metals, including arsenic. Three kilometers is near the length of most horizontal well-bores. The setbacks should be extended at least to 3300 feet.
 - b. The BMP report calls for 1,000 foot setbacks from water wells, and 2,000 feet from public water supplies. Since finding out that contamination can occur when any fracked well is as far away as 3,280 feet. There was another study that found different contaminants associated with fracking within up to 5 miles of gas development. As it is not certain how far these substances can migrate, setbacks need to be at the greatest distance possible.
 - c. Setbacks for well pads and infrastructure from private and public water wells, homes, schools, and office buildings should be at least 3,500 feet. A

recent Duke study found methane in wells up to 1 kilometer away from drilling sites.

- d. The proposed 1000' for private and 2000' public drinking water setbacks in the draft Best Management Practice are not enough. Proposed setbacks allowing drilling 600 feet from "irreplaceable natural areas" and "wild lands" and a mere 300 feet from a stream, river, spring, wetland, pond, reservoir and 100-year floodplain is an unacceptable risk. Based on evidence of methane, ethane, and propane contamination documented by Duke University researchers, MDE and DNR should increase the proposed setbacks to 3,500 feet and should not treat private wells and public groundwater wells differently.
- e. Setbacks of 300 feet from trails or 600 feet from "irreplaceable natural areas" and "wildlands," 1,000 feet from drinking water wells and 2,000 feet from public groundwater wells, surface water intakes and reservoirs all seem inadequate. Setbacks should be increased to 3,000 feet to 4,000 feet.
- f. A setback of 3500 feet should be required to keep drill pads and support facilities such as roads, pipelines and compressors away from water wells (both public and private), schools, homes and office buildings. This is essential to protect clean drinking water and public health and safety.
- g. All drinking water setbacks in the Best Management Practices report should be increased to 3,300 feet.
- h. In Garrett County alone, approximately 14,394 households rely on groundwater wells for their drinking water supply. Given the wider radius of contamination of shallow groundwater resources demonstrated by the most current science, I recommend setbacks for residential and public water supplies no less than 1 kilometer (3,280 ft.)
- i. Setbacks for well pads and infrastructure from private and public water wells, rivers, creeks, homes, schools, and office buildings should be at least 4,500 feet.
- j. Setbacks for well pads and infrastructure from private and public water wells, homes, schools, and office buildings should be at least 1 mile.
- k. Setbacks from all occupied buildings and recreational facilities should be at least 2,000 feet.
- l. The logic evades me; commission the UMCES-AL study, pay for it, then disregard the findings. The setback distances, almost unilaterally have been halved when they should have been doubled or tripled according to the latest research findings.

Ideally, the groundwater flow conditions would be specifically known at every location; in practice, however, this is not possible. Knowing the direction of groundwater flow would enable the Departments to establish a setback to protect users whose wells lie in the direction of the groundwater flow; a lesser setback or no

setback might be appropriate to protect users whose wells lie in the opposite direction. In practice, and for the purpose of establishing setbacks of general applicability, regulators settle on a less scientific radial setback; that is, a distance in all directions, not just in the flow direction.

A recent article, A geochemical context for stray gas investigations in the northern Appalachian Basin: Implications of analyses of natural gases from Neogene-through Devonian-age strata, Baldassare et al., AAPG Bulletin, (February 2014), stated in the Summary and Conclusions section:

Reports of alleged stray gas migration can be the result of preexisting, and previously undiagnosed, methane in the shallow aquifer system, or the result of gas well operations, or other anthropogenic activity. Gas concentration variability in a water well over time can be the result of changes in hydrostatic head induced by pumping or by seasonal fluctuations in the water table. Alleged incidents of stray gas migration require investigations at the site specific level and evaluation and synthesis of multiple data types to determine the source of the stray gas. Site-specific investigations should include definition of gas and groundwater geochemistry and mechanism of migration. Comprehensive predrill groundwater quality sampling is often essential to distinguish preexisting natural gas in the aquifer systems from gas-well activity-induced stray gas migration. Alleged stray gas migration incidents must be monitored and sampled sufficiently following specific methodologies and investigation protocols to determine if the alleged incident is a natural condition or the result of natural gas-well activity.

*The Departments are aware of the peer-reviewed scientific journal articles which report water quality data and assess whether there is a correlation between the concentrations of methane and dissolved metals in well water and distance from gas wells. Some of the articles show a statistical correlation and some do not. For example, Dr. Avner Vengosh, in his presentation at the April 14, 2014, meeting of the Advisory Commission, noted that he found no correlation between methane levels and proximity to gas wells in Arkansas, but that he did find increased stray gas abundance in drinking water wells within a kilometer of active gas wells in a part of northeastern Pennsylvania. Based on isotopic fingerprinting and other factors, he concluded that water wells near gas wells in northeastern Pennsylvania contained Marcellus production gases or a mixture of Marcellus gases and other gases. He wrote: "In cases where the composition of stray gas is consistent with the target shale formation, it is likely that the occurrence of fugitive gas in shallow aquifers is caused by leaky, failing, or improperly installed casings in the natural gas wells. In other cases, hydrocarbon and noble gas data also indicated that fugitive gas from intermediate formations apparently flowed up through the outside of the well annulus and then leaked into the overlying shallow aquifers." Vengosh et al., A Critical Review of the Risks to Water Resources from Unconventional Shale Gas Development and Hydraulic Fracturing in the United States, *Environmental Science and Technology* (2014).*

It is known that methane can appear in drinking water wells in western Maryland without any relationship to gas wells. The Maryland Geological Survey (MGS) recently performed a pilot study to determine background (before horizontal drilling and hydraulic fracturing) methane levels in drinking water wells in Garrett and Allegany Counties. The results are consistent with other reported data that shows a relationship between topography and methane content. MGS categorized wells as 1) in valleys in coal basins; 2) on hilltops or hillsides in coal basins; 3) in valleys but not in coal basins; and 4) on hilltops or hillsides but not in coal basins. The authors report:

With respect to the four well-location categories targeted in this study, ... valley wells in coal basins had the highest proportion of detections (11 of 15 wells, or 73 percent), followed by coal/hilltop+hillside (9 of 20 wells, or 45 percent), non-coal/valley wells (7 of 17 wells, or 41 percent), and non-coal/hilltop+hillside wells (7 of 25 wells, or 28 percent).

The authors also sampled a small number of wells approximately monthly, and found that “The average percent difference from the median monthly methane concentration in each well was between 20 and 30 percent, although individual variations in each well were frequently larger.”

The Vengosh data present a convincing case for contamination of shallow drinking water aquifers by stray gas within 1 km of active Marcellus wells in certain areas of northeastern Pennsylvania. Data from Arkansas indicate that methane concentration in shallow drinking water aquifers does not show an increase with proximity to natural gas wells. During the Advisory Commission’s April 14, 2014, meeting Dr. Vengosh said he does not know why methane is higher in drinking water wells near gas wells in Pennsylvania, but not in Arkansas. The wells were operated by different companies. In Pennsylvania air drilling has been used instead of drilling with mud because it is faster; he speculated that mud drilling may result in better casing and cement. There are geological differences, but there is no strong evidence to say whether the difference lies in better practices or different geology.

If practices lessen the chance of methane release, a combination of practices and setbacks could work together to protect shallow drinking water aquifers. The Departments are proposing specific well casing, cementing, testing and repair best management practices to minimize the rate of well failure and the associated potential for methane migration. These, combined with a significant setback and monitoring requirements, are appropriately protective of drinking water wells.

In its 2011 draft Supplemental Generic Environmental Impact Statement on hydraulic fracturing, the New York State Department of Environmental Conservation recommended “that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000 - foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad.” These two drinking water systems draw from surface water. Such systems are generally required by regulations promulgated under the federal Safe Drinking Water Act, known as the Surface Water Treatment

Rule, to filter the water before delivering it to users. There are two major surface drinking water sources and systems located within New York that have been granted permission by EPA and NY State Department of Health to operate as unfiltered drinking water supplies. These are the New York City and City of Syracuse water supplies and associated watersheds.

Heightened public health concerns are associated with unfiltered surface water systems because the only treatment that these drinking waters receive is basic disinfection through methods such as chlorine addition or ultraviolet light irradiation. There is no use of widely employed treatment measures such as chemical coagulation/flocculation or physical filtration to remove pathogens, sediments, organic matter or other contaminants from the drinking water. Protection of the watershed is the only defense. New York has invested billions of dollars in protecting these watersheds, in part to avoid the additional billions of dollars it would cost to construct a treatment plant and the hundreds of millions a year it would cost to operate the plant.

There are no unfiltered surface drinking water supply watersheds in Garrett or Allegany Counties. If there were, it would be appropriate to consider them for additional protection.

This issue will be closely monitored by the State. The Departments will continue reviewing new research and reports on the relationship between hydraulic fracturing and the concentration of methane and dissolved metals in drinking water wells. These concerns underscore the critical importance of the approach proposed by the State to require comprehensive ground and surface water monitoring in wells and streams, before, during and after hydraulic fracturing events. Regulations are not static and can be changed as new information becomes available.

The Departments accepted almost all of the setbacks recommended by the UMCES-AL report. The exceptions were limestone outcroppings and coal mines, and reasons were given for the suggested changes. The Departments note here that the initial changes to limestone outcrop setbacks have been revised based on a reassessment of limestone outcrop dip angles in Garrett and Allegany Counties. The 500 foot setback from the down-dip side of limestone outcrops has been expanded to 750 feet to provide greater assurances that caves will not be encountered while drilling. The Departments recommended larger setbacks than the UMCES-AL report recommended in some instances.

6. The setbacks are insufficient to protect public safety.
 - a. Fracking infrastructure, like compressor stations and pipelines, has caused explosions and fires in communities in PA, NJ, CA, OK, and more. Your current setbacks of as little as 300 feet are not sufficient to protect Marylanders from these risks.
 - b. Recommend including a 2 mile “disaster mitigation” set back from existing incorporated town limits to emphasize human population safety. See data on recent natural gas compressor station explosions and

evacuation actions by local public safety authorities- usually a 2 mile radius.

- c. There should be a setback from existing communities and concentrated population centers.
- d. The use of open space/agricultural sites or TRULY ZONED industrial sites for compressor stations should be chosen preferentially over sites within 2 miles of established population centers.
- e. The potential for ground water contamination from spills or other conditions where chemicals from fracking mixtures may be involved indicate that the Departments need to review their setback requirements and equally important need to develop baseline data on various chemical parameters as well as methane in water wells and aquifers in Western Maryland.

There have been fires and explosions related to the gas infrastructure. The recommended setback for compressor stations is 1,000 feet from any occupied building. Under federal regulations, all transmission lines are subject to design, installation, construction, and testing and inspection requirements and even intrastate gathering lines are subject to design, installation, construction, and initial testing and inspection requirements if there are more than 10 buildings intended for human occupancy within 220 yards on either side of the center line for any continuous one mile segment of pipeline. These setbacks and standards significantly reduce the risk to public safety.

As noted above, Section 14-108 of the Environment Article of the Maryland Code deals with individual permit applications and requires MDE to deny a well permit if it determines that proposed drilling or well operation poses a substantial threat to public safety or a risk of significant adverse environmental impact to, among other things, populated areas or if the proposed 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 in existence at the time of the application for the permit; or if the operation will have a significant adverse effect on the uses of a publicly owned park, forest, or recreation area in existence at the time of the application for the permit. Section 14-108 requires consideration of the individual permit application, and will be used as appropriate to protect these areas from substantial threats to public safety.

Existing communities and population centers are protected by setbacks and other best practices. An evacuation zone is not comparable to a setback and is often established conservatively when an incident occurs. The Comprehensive Gas Development Plan is one mechanism for directing the location of pads and infrastructure towards areas more appropriate for industrial activities and away from population centers and sensitive natural resource and agricultural areas.

The risk of contamination of groundwater from spills of chemicals and mixtures is addressed through the stormwater requirements and the Spill Prevention, Control and Countermeasures and Emergency Response provisions. The Departments intend

to require baseline monitoring data on relevant chemicals and require periodic monitoring after operations begin.

7. There should be setbacks for infrastructure.
 - a. The State should provide oversight on placement of MSGD infrastructure.
 - b. Considerations of setback requirements should be expanded to include the gas delivery system (gathering lines, etc).
 - c. The draft BMPs recommend a 1,000 ft. setback between a compressor station and an occupied structure. At the very least this restriction should also apply to distance of compressor from cultural assets, waterways and roadways.
 - d. I am also appalled that the state has no control over the siting of compressor stations and gathering lines.
 - e. Compressor station setbacks should be from property lines. As drafted, the BMPs provide a 0' setback from property lines. This creates a safety issue for the adjoining property owner who does not have the benefit of an "occupied building" on their land or near their property line, precluding the peaceful and safe use of their property, as well as limiting future improvement and development of their property.
 - f. Provide a BMP setback for pipes, tanks, valves, and related infrastructure after drilling. This infrastructure presents significant safety, health and environmental hazards should failure or accidents occur. To the extent that these regulatory issues are not in the purview of the MDE or DNR, the Commission should issue a strong statement calling for these to be developed in Maryland, by the appropriate entity, and that no drilling should occur until such time as these protections are put in place
 - g. Are there no setbacks proposed for "infrastructure improvements" such as access roads and pipelines? Road and pipeline construction could impact critical and sensitive areas.

The State plans to oversee placement of MSGD infrastructure by setbacks and by the CGDP. The draft report recommended expanding drill pad location restrictions and setbacks listed in Table 1-2 to all gas development activities that will result in permanent surface alteration that would negatively impact natural, cultural and historic resources. This includes permanent roads, compressor stations, separator facilities and other infrastructure needs. This expansion applies to aquatic habitat, special conservation areas, cultural and historical sites, State and federal parks and forests, trails, wildlife management areas, wild and scenic rivers and scenic byways. The location of gathering lines will also be addressed in the CGDP.

The United States Department of Transportation, Pipeline and Hazardous Materials Administration has established siting restrictions on compressor stations. The regulation, 49 CFR § 192.163(a) provides:

Location of compressor building. Except for a compressor building on a platform located offshore or in inland navigable waters, each main

compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

8. Comments on waivers of setback requirements.
 - a. If setbacks are minimally protective distances, they should never be waived. Parents should not be allowed to consent to waivers on behalf of their children.
 - b. There should be no waivers, and current setbacks are not sufficient.
 - c. Further, while we recognize Garrett County does not currently have county-wide zoning, the study recommends exceptions “for good cause shown and with the consent of the landowner protected by the setback, MDE may approve exceptions to the setback requirements.” Setback provisions, and exceptions, should be developed for contiguous and adjacent properties to protect those landowners.
 - d. The open-ended set-back waiver leaves open the exact door that so many states, specifically West Virginia with only 200 feet, that has been left open where large, industrial HVHF well pads and processes are within a stone’s throw of family’s homes, churches, schools and public areas. Setbacks should be black & white to keep industrial zoning separate from residential and community zoning regardless of what one party thinks it appropriate.
 - e. Allowing individual landowners to waive setback requirements infringes on rights of all other nearby residents to expect full protections from the State’s regulations and from the CGDP process. The provision for exceptions can easily be abused by industry, effectively negating protections put in place in this section. It also opens the possibility of aquifer contamination to occur in a shared water source that might otherwise have been afforded protections if original setback guidance was observed. Setback waivers should only be permitted with the approval of all surrounding landowners who would have been afforded more complete protection if the original setback remained in force.
 - f. No waivers should be allowed to the 1000 feet rule for water wells on private property unless the surface owner is also the mineral rights owner.
 - g. The recommendation should provide a provision that the owner(s) of leased property, the lessor, can allow the well to be located closer than 1000 feet to his own water supply.

The Departments propose to consider requests for exceptions to a setback requirement “for good cause shown and with the consent of the landowner protected

by the setback.” An existing example of a setback requirement and a waiver provision can be found in § 14-112 of the Environment Article, Maryland Code:

(a) Distance from property boundary. --

(1) Except as provided in paragraph (2) of this subsection, a well for the production or underground storage of gas or oil may not be drilled on any property nearer than 1,000 feet to the boundary of the property except by agreement with the owners of the gas and oil on adjacent lands.

(2) A well for the production of coalbed methane may not be drilled on any property nearer than 500 feet to the boundary of the property except by agreement with the owners of coalbed methane on adjacent lands.

(b) When well may be located close to property boundary. -- On property on which it is impossible to locate a well the required minimum distance from the boundary, and where no agreement with the owners of the gas and oil or coalbed methane on adjacent lands has been made, a well may be located nearer than the required minimum distance under subsection (a) of this section to the boundary with the consent of the Department. However, when any permit to drill a well nearer than the required minimum distance to the boundary has been applied for, the Department shall notify every landowner, royalty owner, or leaseholder within the required minimum distance of the location of the proposed well, giving them a reasonable opportunity to file objections to the issuance of the permit. The Department then shall hold a hearing. If the Department determines that it is necessary for the well to be located nearer than the required minimum distance to the boundary, it may issue the permit. If a permit is issued, any landowner, royalty owner, or leaseholder within the required minimum distance of the proposed well has the right to a rehearing and appeal to the courts provided in this subtitle. A request for a rehearing or an appeal to the courts stays the authority granted under the permit until final determination of the issued permit is made.

Another example can be found in COMAR 26.19.01.09G:

The Department may not issue a drilling and operating permit if the well location is closer than 1,000 feet to a school, church, drinking water supply, wellhead protection area, or an occupied dwelling unless written permission of the owners is submitted with the application and approved by the Department.

In general, people are free to voluntarily relinquish a right, such as the right not to have a well drilled closer than 1,000 feet to an occupied dwelling. If the Department of the Environment determined that the proposed operation with the waiver would pose a substantial threat to public safety, it could not grant the permit with the waiver.

Whether a parent can waive a child's rights is a question that arises in many contexts. It is a matter of state law.

9. General setbacks are not appropriate; local conditions should be considered.
 - a. It is problematic to apply standard setback requirements to local geological conditions; site-specific formations must be considered.
 - b. Setback requirements for the several categories appear to be somewhat arbitrary and not based in topographic realities. Each proposed setback should be reviewed and analyzed against protections for environment; public health, welfare and safety; defense of Garrett County's tourism and outdoor / adventure industries; and for protection of property values of contiguous and nearby properties to Marcellus gas operations.
 - c. Natural fractures of the bedrock beneath central and western Maryland contain potential drinking water resources, and shale gas boreholes should be set back from these geological features. These fractures complicate the casing and cementing of wells that pass through them, increasing the risk of subsurface leaks.
 - d. The 1320 foot setback from historic gas wells (from both the vertical and horizontal well bore) is being recommended with no real technical basis. It may be reasonable to recommend "identification" of existing wells within a certain, somewhat arbitrary, distance as part of the permitting process to ensure those wells are appropriately recognized and considered, but it's an entirely different issue to establish that as a mandatory setback. Setbacks should be established to balance environmental protection and development. Overly restrictive setbacks can have the unintended consequence of essentially reducing the area available for drilling.
 - e. The setback requirements should not be arbitrarily picked and there should be some criteria and a scientific basis rather than a "farther is better" approach.
 - f. If the State mandates a 2,000 setback from existing and historic gas extraction activities, it is unclear how the State can also permit much larger, deeper and more complex wells to be drilled in close proximity to other wells on a CGDP well pad.
 - g. In addition to historic gas wells, there should be consideration to setbacks or conditions placed on fracking near existing production wells. Fracking near existing wells can result in a "frack hit" on an active production well that could result in a blowout of the well equipment on the production well. This problem can be avoided either by setbacks or by special preparation of the production well to handle a possible "frack hit".

Setbacks are general rules that are appropriate in most cases. Site specific information will be considered, however, in both the CGDP and the application for the individual permit. Any oil or gas well drilled from the surface will pass through freshwater aquifers. The best practices requiring pilot holes, setbacks from limestone

outcroppings, and those relating to casing and cement provide a measure of protection from subsurface contamination.

Current regulation COMAR 26.19.01.09E currently provides:

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.

This regulation was written before the widespread use of horizontal drilling and multi-well pads. This regulation will have to be amended or an additional regulation specific to multi-well pads will have to be developed. The Departments will consider the existence of existing gas wells when reviewing permit applications. The draft report recommended that all portions of the borehole, including laterals, should be at least 1320 feet from historic gas wells.

10. Clarification is needed.

- a. Depending on how the terms “stream” and “seep” are defined, these aquatic habitats may not be adequately mapped.
- b. It would be helpful to have a definition of “for good cause shown” in connection with waivers of setbacks.
- c. There are a number of proposed setbacks within the document, many of which are in conflict with each other. For example, it is unclear on page 30 with respect to the drilling of a pilot hole within 500 feet of the proposed borehole, whether the setbacks for the pilot hole would be the same as for the final developed well. There are no provisions for using the same pilot hole for the main borehole of the well if no issues are identified during its drilling.
- d. Another example of significant uncertainty in the document is with the 300 feet setback from various “recreational use areas” clearly recommended on page 16, versus the suggestion on page 18 that it may be doubled to 600 feet based on a workshop anticipated later this year.
- e. In Table I-2, the “to” section describes from the “edge of the drill pad disturbance” and should include a descriptive outline that includes the sedimentation and erosion controls and storm water controls as the limits of disturbance (LOD) for the setbacks.
- f. Setback from Compressor station – The table does not make it clear whether the setback from an occupied buildings for compressor stations is from the actual building housing the compressor, or from the building and associated infrastructure, or from the limits of the property that houses the compressor station. This should be clarified.
- g. Avoiding times of peak outdoor recreational periods is meaningless if an exception is allowed based on the assertion that once fracturing operations have begun, it is generally not safe to halt activities. This exception will diminish the State’s ability to restrict the timing of fracturing activities.

The driller is essentially enabled to ignore peak recreational periods and wildlife needs, conduct the hydraulic fracturing phase at will, and claim that it is unsafe to halt activities because they have already begun.

- h. The provision recommending that drilling should avoid times of peak outdoor recreational periods is unreasonably restrictive. What purpose is served by restricting drilling on first day of trout season verses any other day of trout fishing? Not likely that the trout will quit biting in the Potomac River if a gas well drilling operation starts near Keyser's Ridge.
- i. The setback for occupied buildings should be 1,000 feet from the well site and compressor equipment (if located off-site) instead of the proposed borehole. Should a structure holding livestock be defined as “occupied?” Noise, vibrations, odors and light will impact adjacent buildings. In addition, setback consideration should be made for unoccupied agricultural buildings (such as hay storage).
- j. The recommendation on conservation banking for forests [a Siting Best Practice] does not make clear how conservation banking will be used. Does this mean that the drilling company can undertake or contribute to conservation efforts elsewhere if impacts in western Maryland cannot be avoided? Will the Agencies consider credit trading to satisfy forest conservation mitigation for western Maryland forests? Will a local stakeholder be a part of decision-making regarding the use of conservation banking?
- k. Setbacks from floodplains should increase and be based on a minimum distance and elevation, whichever is greater.
- l. Why is there a setback for wildlife but not for livestock?
- m. All BMPs of setbacks from “occupied building” should be changed to property line. Rural areas are sparsely populated and have more land parcels than occupied buildings. Setbacks are more appropriately set from property boundaries to afford equal protection to all landowners, regardless of the extent of the current development and use of their property. Setbacks from property lines are the standard approach in almost all land use regulations.
- n. The BMPs provide minimum setbacks for public drinking water protection - only public groundwater wells or surface water intakes have setbacks. Public drinking water source areas outside of the intake or well setback zone receive only the 300’ aquatic habitat setback.
- o. The towns of Friendsville and Oakland use the Youghiogeny River as a public drinking water source. Setback protections from the main stem of the Youghiogeny River upstream from Friendsville and Oakland should be the most stringent – 2000’ as a drinking water source and not the 300’ aquatic habitat standard.

- p. Our county, state and federal lands and resources cannot be used to drill by the fracking/gas companies, in order to preserve nature, protect our wildlife, and the water that flows through it.
- q. Fracking and or drilling cannot take place within 200 yards of any private well or public water sanitation areas.
- r. Fracking underground of personal property without their express written permission of the landowner, would not be permitted. In addition, that landowner would also receive a royalty fee from the company and eligible to make claims against the shale fracking/drilling companies, if warranted.
- s. For aquatic habitat (riparian), the UMCES-AL Report cited recommended varying setbacks based on biodiversity. The lowest setback was 330 feet and the greatest was 1,240 feet (Table 5-2 and page 6-4). Why are the Departments recommending a setback of 300 feet? Does the setback provide adequate protection? Usually riparian areas are protected by vegetated buffers. Will these buffer areas be factored into the setback calculation?
- t. For drinking water wells and surface water intakes, the UMCES-AL report recommends “extended” setbacks from on-site storage areas, hazardous materials and collection tanks for produced water. Should additional setbacks be proposed?
- u. Since setbacks offer the primary protection, it is extremely important that they are correctly identified, including whether they are measured from the borehole or the edge of the pad.
- v. The report recommends expanding drill pad location restrictions and setbacks listed in Table 1-1 to all gas Development activities resulting in permanent surface alteration that would negatively impact natural, cultural and historic resources. This would severely restrictive for roads and infrastructure. This provision could make it impossible to put in gas pipelines through or along county roads in state parks and lands and perhaps even difficult to construct a road from public right of way to a well site. This provision conflicts with the intent of the report to limit development impacts and forest bifurcation.
- w. Expanding the setbacks from public outdoor recreational use areas would give the State control over massive amounts of private property and restrict landowner's ability to lease or have natural gas development on their property that borders on state land if these setbacks include all aspects of natural gas development.
- x. Section IV.B.2 suggests that forest loss could be evaluated differently depending on whether the loss is temporary or permanent. How could a forest loss be temporary?

Not all “streams” and “seeps” may be mapped, but the applicant for a CGDP will be required to do a rapid field assessment for unmapped streams, wetlands and other sensitive areas.

“For good cause shown” is a general phrase meaning that a reasonable basis must be demonstrated. It appears multiple times in Maryland statutes and regulations.

Where two different setbacks apply, the applicant would have to comply with the more stringent setback. A pilot hole that is not a gas well and does not become a gas well would not be subject to the setback regulations for gas wells. Provided the pilot hole meets the requirements for a gas well, the company could make application for a gas well permit and use the pilot hole for the borehole.

It should be assumed that the Departments will propose to adopt the recommended setbacks. Understand, however, that regulations can be changed, and more stringent provisions can be incorporated into individual permits.

The words “edge of the drill pad disturbance” will be clarified. It was meant to refer to the limit of disturbance as indicated in the grading plan for the drill pad.

The 1,000 foot setback for compressor stations will be measured from the building or buildings that contain the compressor station operations. As noted above, there are federal regulations that impose siting restrictions on compressor stations.

Although fracking is generally carried out without pause, the date on which the fracking begins can be largely controlled. The times of peak outdoor recreation can be anticipated. Garrett County sees heavy tourist travel to parks on routes, such as State Park and Rock Lodge Roads around Deep Creek Lake NRMA and Deep Creek Lake State Park. The initiation of drilling and fracking, along with the accompanying truck traffic, could be timed to reduce safety hazards to hikers, bikers, boaters, and park patron traffic during the summer months. Similar logic applies to the first day of trout season. This kick-off day attracts many anglers to the roadways and streams in western Maryland. The State would like to minimize the public safety hazards on this high traffic day. Of course, the proximity of the recreational activity to the hydraulic fracturing site would also be considered.

The Departments agree that the 1,000 setback for occupied buildings should be measured from the edge of the well pad, not the borehole. A structure occupied by livestock would not be considered “occupied.” These and unoccupied farm buildings should be adequately addressed by other setbacks and best practices.

The Departments prefer that forest mitigation through conservation banking or another mechanism occurs within the affected county of impact, and ideally within the affected watershed. However, the State realizes that reforestation opportunities may be limited and that the mitigation actions may need to occur outside of western Maryland. The State will encourage stakeholder review as these mitigation options are developed. Setbacks from floodplains, like other setbacks, can be adjusted in permits. The draft report recommended that well pads shall not be constructed on land with a slope > 15 percent. It also stated that setback distances may be expanded on a case by case basis if the area includes steep slopes or highly erodible soils.

There are setbacks for wildlife management areas, not for wildlife per se.

There are reasons for establishing some setbacks from the property line and others from occupied buildings. For example, existing law, which the Departments do not recommend changing, requires that a well be at least 1,000 feet from the boundary of

the property on which the well is to be drilled (unless MDE grants a waiver). Section 14-112 of the Environment Article of the Environment Code and COMAR 26.19.01.09C and D. This would mean that the well cannot be closer than 1,000 feet from another person's property line, whether the other person's property has been improved or is raw land. Another existing regulation requires that a well be at least 1,000 feet from a church or occupied dwelling unless the property owners consent in writing. COMAR 26.19.01.09G. This provision would protect an occupied dwelling on the property on which the well will be drilled.

The Departments are proposing more protective setbacks for sources of drinking water. See the response to comment 4, above.

The draft report recommended that all cultural and historical sites, state and federal parks, trails, wildlife management areas, scenic and wild rivers, and scenic byways be off limits to surface disturbance and be further protected by a setback of 300 feet. The Department of Natural Resources' written policy states, "Use of water resources or water rights from lands owned and managed by DNR may only be granted for documented remediation of severe human health or safety needs."

With regard to the reference to "public water sanitation areas," the Departments assume the reference is to wellhead protection areas. The Departments are proposing a 1,000 foot setback from such areas.

Wells cannot be drilled or fracked on or under land unless the owner of the mineral rights consents. In the event that the surface rights and mineral rights are held by different persons, the surface owner must make reasonable accommodations to the holder of the mineral rights to allow the extraction of gas or other minerals from under the surface owner's land. Greater clarity and more protection could be established by a Surface Owner's Protection Act (SOPA), which has been enacted in some jurisdictions. The Advisory Commission was not able to agree on comprehensive provisions of a SOPA.

The UMCES-AL report cited research regarding appropriate setbacks for different species in aquatic habitat, but recommended a 300 foot setback. The Departments initially accepted the recommendation, but, upon further review of scientific literature, expanded the aquatic habitat setback to 450 feet for biodiversity and water quality protection. Setbacks are measured from edge of the targeted habitat and define the buffer width. While trees are generally considered the most protective vegetation type for habitat and water quality, the buffer may include other types of vegetation.

The Departments are recommending that secondary containment be mandatory for chemical storage areas and tanks. For this reason, no additional setbacks are proposed.

The Departments will be specific as to whether setbacks should be measured from the borehole or the edge of the pad.

The setbacks for permanent surface alteration that would negatively impact natural, cultural and historic resources will not restrict such alterations unless there were a

permanent negative impact. It is anticipated that a very small percentage of such alterations would have such an impact.

The setbacks from public outdoor recreational use areas are restrictions on surface disturbance. With horizontal drilling, these areas will not be off-limits to gas development.

Temporary forest loss occurs when an area has been cleared for a temporary use, but will then be allowed to re-grow back to a forest. The reforestation may occur naturally over time or through planting activities. This situation could occur if forest is cleared for a drill pad and then the area of the pad is reduced, allowing a certain portion of the cleared area to be reforested. If the loss is permanent, this would be used to justify higher reforestation or conservation mitigation ratios. For example, for one acre of permanent forest loss, two acres may be required to offset the impact. Mitigation ratios for temporary losses may not be as high.

11. The setback should consider the horizontal wellbore and not only the vertical wellbore or the edge of the pad.
 - a. A setback of 1,000 feet is inadequate on its own terms and close to meaningless if horizontal drilling extends the exploitation zone thousands of feet in every direction from the well pad.
 - b. The setback distances in general sound okay, but when dealing with drinking water reservoirs, such as the Frostburg Reservoir and others in Garrett County, the distances should be greater than those recommended by Eshleman and Elmore. If horizontal boreholes can extend 7000 feet, I think that the setback distance from key drinking water resources should be at least 7000 feet.
 - c. The setbacks should consider not only contamination from events at the land surface, but also those that occur beneath.
 - d. The currently specified setback from any drinking water well presumes that contamination comes from pollution events that occur at or near the land surface (on the pad, in collection ponds, whatever). Events that are inevitably occurring beneath the land surface are ignored. Ignorance is no excuse when protection of natural resources and the health of citizens are involved.
 - e. The “Location restrictions” discussion ignores the effects on wetlands, fresh water aquifers, etc., of the upward migration of induced zones of enhanced vertical permeability. Unfortunately, criteria for “setbacks” are applied only to the pad and to other activities and events taking place at the land surface. These applications are necessary, but are not sufficient. Though one can expect historic gas wells (and environs) to mark locations where vertical upward flow of gas and pollutants may occur, they do not mark the only locations where one can expect to find sooner or later zones of enhanced vertical permeability that eventually will reach the land surface and hence will introduce future upward flow of methane gas not only to fresh water aquifers and wetlands, but also to the atmosphere. One

should also consider the effect that formation-to-formation geologic heterogeneities have on the mapping of where zones of enhanced permeability may be expected to migrate. Ditto for the locations and geometries of deep coal mines.

- f. If the horizontal part of the well could be drilled as far as 8,000 feet, property lines are not protected if the setback is 1,000 feet!

The risk of contamination of surface water and drinking water aquifers arises mainly from activity at the surface or from deficiencies in the casing and cementing of the vertical borehole. The hydraulic fracturing occurring at depths 2,000 or more feet below the lowest drinking water aquifer poses little threat. The issue of upward migration is addressed in the responses to other comments.

12. The recommended setback from coal mines are appropriate. UMCES-AL recommendations with regard to setbacks from mapped underground coal mines to the borehole are unnecessarily restrictive, as appropriately noted by the Departments in the August, 2013 Draft Marcellus Shale Safe Drilling Initiative Study Part II. The Board of Directors and committee members of the Casselman Coal Poolee Association endorse the Departments recommendations with regard to this critical issue. Pre-drill planning including careful site evaluation and pilot hole investigations is the safest and most effective method to identify these features. As noted by MDE's mining program, Maryland's deep coal mines cover thousands of acres, but are only several hundred feet deep, and can be safely cased through, utilizing pilot holes to precisely identify and locate any voids. The MDE and DNR have appropriately proposed that the best practice is to conduct pre-drill planning in any area where underground mining is suspected within 500 feet of the prospective borehole, based on a review of available records. The Departments have recommended that the pre-drill planning shall include selection of drill hole locations that avoid all mine voids and assures lateral support of drill holes during drilling and casings during well construction. If such locations cannot be found, voids must be filled or isolated with multiple concentric strings of casing and cement. We fully endorse these recommendations.

The Departments agree.

TRUCK TRAFFIC

1. Consideration should be given to truck traffic adjacent to schools. The amount of dust and particle emissions from the diesel engines would impact the health of school children, especially those on playgrounds. It is common practice for truck owners to modify their diesel injection systems to generate more power. However, the result of these modifications is a large increase in black soot from the trucks' tailpipes. This will need to be regulated if the trucks are to go past a school.

The review of roads and travel routes would be a consideration in the Comprehensive Plan initially when the planning phase of development would occur. Truck routes and times would be discussed more thoroughly in the context of individual permit. County and State roads agencies as well as other local agencies will need to be a part

of this discussion and in most cases will take the lead in this effort. Any commercial vehicle needs to meet the requirements of current transportation law and will be subject to penalties for non compliance. Steps will be taken to ensure inspection of trucks.

2. The report's recommendations fail to recognize that most of the truck traffic generated from Marcellus Shale drilling is short-term, typically occurring over a few months during site preparation of the well (e.g., hauling pipe, water, etc.). Once a well is established, truck traffic significantly decreases as gas is transported via pipeline.

This is a valid point, but truck traffic can be very heavy over the short term, and the "short term" can last for a long time if multiple wells are drilled. In addition, the Departments must consider cumulative impact.

3. Do we demand the companies profiting from MSGD be financially responsible for the effect of the increased heavy vehicle traffic on our roads, or go the way of Texas and just let our roads revert to gravel?

Oversize or overweight vehicles must obtain special permits to travel on State roads, and the permittee is responsible for payment of all damage that the vehicle causes, either directly or indirectly, to any road surface, bridge, or other structure, whether maintained by the State Highway Administration or by another entity. Trucks pay State roadway taxes and fees that are meant to provide for the upkeep of state roads from normal (not overweight or oversize) vehicles.

Counties also have weight restrictions on some roads. Experience has shown, however, that even vehicles that are within weight and size restrictions can cause damage to local roads if, for example, the truck trips are frequent or occur during freeze and thaw periods. The draft best practices report included a requirement that the applicant must "enter into agreements with the county and/or municipality to maintain the roads which it makes use of, in 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." This can be accomplished through a Road Use Agreement between the applicant and the County or municipality. Such agreements are common, and the Departments expect they will be used for this purpose.

4. Not only will the road and bridge infrastructure be damaged, but we also foresee very significant safety issues particularly where the large trucks and concentration of activity on small county and park roads will undoubtedly lead to a significant increase in accidents. Traffic patterns and road usage would have to be closely monitored or prohibited in some cases.

See response to comment #1.

5. Please change "should" to "shall" in "Trucking should be closely monitored during high-use and wet periods if it is not possible to suspend activities."

Monitoring will be done when necessary.

6. It may be politically difficult for local officials to enforce agreements with companies to fix roads or pay for them. It might be better for the State to take on this responsibility.

The State is willing to work with the Counties to ensure that roads are maintained, but the primary responsibility for maintenance and repair of the roads is with the county or state roads agency responsible for that particular road. See response to comment #3.

7. There are several comments on timing of heavy trucking. The highlighted times listed on page 26 are an extension of API recommendations that a transportation plan be incorporated into the overall project plan and that the plan address traffic needs. A more complete review of the recommendations contained in the API recommended practices associated with transportation planning could assist the state in this area.

An API standard relating to transportation planning would qualify as a "relevant API standard." The best practice report requires that the applicant for a well permit file a plan that follows the normative elements of relevant API standards, or demonstrate that an alternative is at least as protective.

8. Many of the recommendations included are unrealistic. For example, encouraging "maximum movement of heavy equipment by rail to protect road systems and prevent accidents" is idealistic. While rail is a viable long-haul transportation option, the last miles traveled in the geographic region will ultimately be made on a truck. The requirement that "all trucks, tankers and dump trucks transporting liquid or solid wastes be fitted with GPS tracking systems" is virtually impossible in an industry that is deregulated, highly fragmented, and uses a large number of independent contractors to meet short-term transportation needs.

The Departments realize that there will inevitably be truck traffic to individual well sites. The purpose of the statement was to recommend consideration of other means of transportation where available. The use of GPS in tracking is becoming more common, and the permittee can require the use of such equipment by trucks serving the permittee's operations.

9. "Encourage local jurisdictions to develop adequate transportation plans." The Transportation study funded in the Governor's 2013 budget has not yet begun. When developing the scope of this study, the Departments should include the "local jurisdictions" to assure compliance with the policies to be adopted. In addition, there are several road projects under consideration (495 Truck Route) in the region that will have impacts on truck traffic and early involvement in developmental strategies at the state and local level would assure a unified approach to that development.

The Executive Order requires the Departments to address "the risks of traffic accidents and damage to roads and bridges from truck traffic related to drilling operations." The Departments, in consultation with the local jurisdictions, are addressing these issues.

10. All trucks associated with the development of a well permit must have GPS real time spatial data to allow for tracking.

See response to comment #8. The GPS system will record both time and location.

11. As part of the CGDP, MDE should mandate trucking routes and haul times.

Truck routes and haul times will be addressed in the CGDP and specified in drilling and operating permits.

12. The implementation and oversight of transportation and trucking to coordinate the timing of oil and gas activities to avoid conflict and minimize damage to roads on public lands is voluntary and thus unenforceable.

Once the transportation plan has been submitted and approved, it will be incorporated into the permit. As a condition of the permit, it would be enforceable.

13. The discussion of road construction standards appears comprehensive. However, the topic of who pays for public road maintenance is not addressed.

See response #3.

14. Trucks should be prohibited from hauling anything except during the following times: 8:30 AM-4:30 PM, as not to disrupt the peace of the local community and provide safe travel for school buses. In addition, the trucks should be prohibited from traveling through sensitive areas, such as towns and schools, because of hazardous risks.

A safe and efficient truck route will be part of the CGDP and individual permits. School bus routes will be taken into account. Some towns and communities in Allegany and Garrett Counties are on major traffic routes and experience significant truck traffic, including trucks carrying coal, gasoline, propane and logs. These probably involve as much risk as a truck hauling fresh water or wastewater from gas operations.

15. The report recommends that the applicant enter into agreements with the local government and or public land managers to maintain roads which it makes use of, in the same or better condition prior to mining operations. Is this permitted by State law? Would it be acceptable for the applicant to make repairs on public roads? What options might be available for the community to collect funds from the applicant and make the repairs themselves?

See response #3.

16. There appears to be a serious lack of regulation/enforcement regarding transportation of volatile and dangerous materials (waste water) via trucks as they navigate our rural roads and, in particular, towns and villages. BMP's should include recommendations for truck routes, for example.

Hazardous materials transportation is regulated by the federal Department of Transportation. Its requirements include such things as licensing of drivers, packaging, and placarding. Truck routes will be addressed in the CGDP and individual permits.

WASTE DISPOSAL

1. General.

- a. Waste disposal is problematic since there is no safe disposal method.
- b. The report does little to address how fracking wastewater will be disposed of in Maryland. In other states that failure to regulate wastewater disposal, the underground injection of this toxic fluid has been linked to earthquakes and contaminated drinking water.
- c. The current permit does not address the disposal requirements for natural gas development.
- d. Tens of millions of gallons of toxic waste, as well as large amounts of residual solid waste from the recycling process that would require safe disposal. The report fails to address this problem.

The Departments acknowledge that waste disposal is an important issue. Waste management and waste disposal are discussed in the draft best practices report in Section VI.K and Section VII.

- e. The waste from glycol dehydrators should be disposed of properly.

Existing law requires that all wastes be disposed of properly.

- f. Provide for disposal of the water that returns from the well – laden with sand, antibiotics, salts and sometimes radioactive material from miles down in the earth.
- g. The handling and disposal of radioactive wastewater and sludge needs to be addressed.

This issue is discussed in the draft best practices report at VII.E. Cuttings, flowback, 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 the law at a facility permitted to accept it. This would address both naturally occurring radioactive material (NORM) and technologically enhanced NORM (TENORM).

- h. Accidental spills at handling facilities, leakage from trucks and railroad tank cars, spillage due to human error, worn out equipment, wrecks, etc. Furthermore, neither underground nor surface storage facilities are fully foolproof, accident-proof, or earthquake proof. One way or another, an unacceptable quantity of these chemicals will eventually end up in the environment, “best practices” notwithstanding.

Human error and accidents are inevitable. The best practices seek to minimize the chance that releases of pollutants will occur, to require containment of any spills that occur on the pad, and mandate cleanup of spills.

- i. A county not far north of where I live has taken to using diluted produced water to melt roadway ice, and a mechanic our family knows states that

the frequency of vehicles brought in for repairs following catastrophic undercarriage/frame failure has gone up five- to ten-fold.

Produced water is high in salts, and it is not surprising that the uncontrolled or excessive application of salty water to roadways could damage vehicles and the environment.

2. Transportation and tracking of wastes.

- a. Wells require 4 to 5 million gallons of fresh water to frack, multiply that by 1000 wells and that by the 2 or 3 times a well will need to be refracked in its lifetime and you have up to 20 billion gallons of hopelessly polluted water that need to be disposed of. Piped or trucked out, some kind of permitting and tracking of this waste is called for.

The current trend is for much of the flowback and produced water to be recycled. The draft best practices report addresses tracking the production, shipment, and disposal of this wastewater in Section VI.K.

- b. Placarding and GPS tracking/logs should be required for all waste hauling vehicles because of increased truck traffic carrying toxic fracking waste.
- c. Since the waste is toxic all trucks/vehicles hauling the waste should be well labeled and their routes logged. Placarding and GPS tracking/logs should be required for all waste hauling vehicles because of increased truck traffic carrying toxic fracking waste.
- d. If those transporting this had tracking and kept logs as well as using tracer chemicals to track illegally dumped water I might feel a bit safer.
- e. Unique tracer chemicals should be included in fracking wastewater, so that illegal dumpers can be more easily tracked.
- f. The decision to not allow for waste disposal in Maryland is important and requirements by the Departments for logging and identifying shipments, materials being hauled, hauler, date, and name, address, shipment amount, and date of the receiving facility are all critical to protecting Maryland's environment and the safety of its citizens. However, MAC believes that a final requirement for this important process would be to add a real time manifest reporting and a GPS truck tracking system to the process. The lack of an effective monitoring system will like all other critical parts of MSGD is a flaw that leads to the inability to detect and manage significant problems when they occur.
- g. The requirement that all drilling related trucks be equipped with monitoring devices is an excellent idea. There must be official logging and storage of this data during the drilling operations so the data can be reviewed if there is a question of inappropriate disposal of waste products or an accidental spillage.

The movement of hazardous materials is regulated by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration. Hazardous materials include such things as explosives, flammable materials, poisons,

oxidizers, infectious substances, and corrosive substances. If the material transported qualifies as hazardous, the regulations address many aspects of the handling, including packaging, placarding, shipping papers, and driver qualifications. Placards provide a brief, generic description, and do not convey detailed information on waste characteristics.

In order to assure that all wastes and wastewater are properly treated or disposed of, regardless of whether they meet the definition of “hazardous” the best practices report requires permittees 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 confirmation that the shipment arrived at the designated disposal facility. In addition, all trucks, tankers and dump trucks transporting liquid or solid wastes will be fitted with GPS tracking systems. These systems will record the location of the vehicles over time. The records can be reviewed if there is a report of a spill or if the shipping papers suggest that the wastes did not arrive at the designated facility.

A program for adding tracer chemicals to wastewater would be hard to design and enforce, and would not necessarily make it any easier to detect illegal dumping. For example, if wastewater were illegally discharged into a flowing stream, it would likely travel a considerable distance and experience dilution before anyone noticed and reported the spill. Samples from the stream might have such low levels of the tracer chemical as to be undetectable. The draft best practices report addresses the issue of illegal dumping by requiring that all trucks, tankers and dump trucks transporting liquid or solid wastes be fitted with GPS tracking systems, and by requiring recordkeeping of wastes shipped and confirmation that the waste was received at the facility authorized to accept it.

3. Use of Class II injection wells.

- a. MDE should consider eliminating Class II injection wells as a wastewater disposal option.

Class II injection wells are currently the best option for disposal of wastewater from HVHF.

- b. Shouldn't we consider all HVHF wells Class II UIC wells if waste is, essentially, stored in them? If we are actually “storing” waste in every well we drill, does it matter that our geology is not considered suitable for this purpose?

In the broadest sense, a HVHF well could be considered an injection well because it is a “well” into which “fluids” are being injected; however, it is not defined or regulated this way. Production wells bring oil and gas to the surface; the UIC Program does not regulate wells that are solely used for production. There are three types of Class II injection wells: Enhanced Recovery Wells inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and—in some limited applications—natural gas; Disposal Wells inject brines and other fluids associated with the production of oil and natural gas or natural gas storage operations; and Hydrocarbon Storage Wells inject liquid hydrocarbons in

underground formations (such as salt caverns) where they are stored, generally, as part of the U.S. Strategic Petroleum Reserve.

4. Disposal in wastewater treatment plants (WWTPs), landfills and on-site.
 - a. Water from this industrial process should not be treated at a local sewage treatment facility which is not equipped to handle these kinds of chemicals.
 - b. Just like any other industrial activity, Maryland should prepare to permit and regulate treatment and pretreatment of industrial waste from natural gas drilling activity. I do believe that every publicly owned treatment plant (POTW) and public WWTP is required to have pretreatment requirements for any industrial discharge into the WWTP. The EPA rule for shale gas wastewater if available by 2014 should be used as the standard for pretreatment if discharges are to occur into a POTWs or public WWTPs. Until these regulations are in place MDE should require that POTWs and WWTPs not accept these wastewaters without prior consultation with MDE.
 - c. Although EPA has committed to develop standards to ensure that hydraulic fracturing wastewaters receives proper treatment and can be properly handled by POTWs. However, their plan is not to propose rules for wastewater until 2014. Until these regulations are in place, the Agencies must create the most prohibitive practices and regulations on disposal and/or treatment of hydraulic fracturing flowback.
 - d. Substances that are buried in the earth and come to the surface with the fracking-released gases or fluids. They include toxic chemical salts, salts of boron, cadmium, arsenic and a variety of heavy metals, including radioactive ones. These salts cannot be disposed of by local wastewater treatment plants, nor can they be safely consigned to regional landfills. The EPA has successfully filed a number of suits against firms that have attempted these ways of disposing of frack-induced undesirable salts.

MDE has taken appropriate steps to prevent the discharge of hydraulic fracturing wastewaters to wastewater treatment plants. When EPA promulgates pretreatment standards, MDE will consider whether any wastewater treatment plants in Maryland should be allowed to treat that water.

- e. Rock cuttings, about the size of coarse grains of sand, must be disposed of, and they are coated with used drilling fluids that can contain contaminants such as benzene, cadmium, arsenic, mercury and radium-226. These wastes may present other problems for landfills, beyond radioactivity.

Non-liquid wastes may 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.

- f. For cuttings disposal, there is an unclear criteria that if the cuttings meet other criteria established by MDE, then on site disposal of the cuttings could be allowed. There is no information as to what the other criteria may be. This means for planning purposes, all wells would require hauling off of cuttings and the initial plan would include increased trucking to move the cuttings. This creates an immediate bias in the plan and artificially inflates the potential traffic from the drilling site.
- g. Maryland should not permit onsite disposal of cuttings and drilling mud.

The draft best practices report stated: "The Departments agree that the cuttings and drilling mud should be tested for radioactivity, but recommend that they also be tested for 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." COMAR 26.19.01.11W. 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.

5. Recycling.

- a. Audubon further supports the proposed guideline for recycling 90 percent of flowback and produced waters in subsequent drilling activities and for the policy preference for on-site re-use.
- b. While encouraging recycling and reuse of water is appropriate, the requirement for 90 percent recycling "on the pad site of generation" is unrealistic due to the number of inherent operational variables. To achieve that high level of recycling can require use of specialized equipment that not only requires additional space, but also needs enough volume throughput to be practicable. Allowing for transport of flow back and produced waters to a centralized recycling facility has the potential to improve reuse and recycling of the water. Again, this topic is covered in the API recommended practices with respect to water use and reuse for hydraulic fracturing operations.
- c. The 90 percent water reuse is a sound goal which some companies are already doing on some sites but this should not be a fixed requirement which will allow companies to adapt to the appropriate conditions.
- d. In addition to the risks of chemicals pumped into the ground, large volumes of water return to the surface with the same chemicals, plus radiotoxic brine. The Report calls for recycling of this water "to the maximum extent practicable". This language is vague and leaves many questions of risk: how is 'practicable' determined? How clean must the 'recycled' water be? What is done with the contaminants that are removed in the water recycling? There are many such unresolved questions, and in

most cases, there is a financial incentive to underestimate the long-term costs and complications.

A percentage of the fracking fluid returns up the borehole to the surface; based on information from Marcellus wells in other states, it is anticipated that about 30 percent of the water will return. The trend is to recycle this flowback for reuse in another fracturing job. It needs to be as “clean” as necessary for reuse in HVHF. Residuals from treatment must be disposed of in accordance with law. The flowback that cannot be recycled is usually disposed of in Class II injection wells. There are no such wells in Maryland. The waste is usually sent by truck. The best practices report recommends a tracking system for wastes.

The Departments realize that it will not always be feasible to recycle flowback on site, and the recommendation took this into account. The draft report said “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.” Treatment at a centralized treatment plant will require additional truck trips. The applicant for a drilling permit must submit a plan for storage, treatment and disposal of water and wastewater. The Department of the Environment will review that plan, and any claim by the applicant that recycling is not practicable.

“Practicable” is a term often used in laws and regulations. It is used interchangeably with “feasible” and describes an idea or activity that can be brought to fruition or reality without unreasonable demands. In the draft Best Practices report, “practicable” is often used in connection with a plan that, once approved, becomes part of the permit. The approved plan, which will be incorporated into the permit, will be specific as to the recycling and sufficiently clear to determine compliance or noncompliance.

WATER USE

1. The amount of water needed is too great for the benefit.

Maryland law requires that proposed water uses be evaluated to ensure that 1) the amount of water used is not wasteful for the proposed use, 2) the water use does not cause unreasonable impacts to the water resource, and 3) the water use does not cause unreasonable impacts to other users. Any request for water appropriation for fracking would be subject to this analysis.

2. Every frack uses up to 4 million gallons of water. In the western states where fracking continues, whole towns have run out of water. One frack in Maryland would use about one day’s worth of water for the people living over the shale. Fracking uses immense amounts of fresh water which is irreplaceable, and that effect occurs even when other damage might (or might not) be successfully minimized.

During a year with average precipitation, over 1.3 billion gallons of water falls on Garrett County, on average, each day. The impact of a proposed water withdrawal is evaluated based on its particular location, the rate of withdrawal and the duration of

the withdrawal. It is difficult to generalize the impacts of water use, as each situation is unique. MDE requires applicants to assess the impacts of their proposed use on other users, conducts an independent evaluation of impacts and would not issue a water appropriation permit for a use that would cause adverse impacts to a water supply. Permits are written to ensure that impacts to the resource and other users are not unreasonable, and permits contain conditions intended to prevent or mitigate any impacts.

3. Maryland must revise its permitting regulations to address these water issues, Maryland must require withdrawals be only from large rivers or reservoirs.

Maryland has robust regulations to appropriately manage requested water uses in the State. Property owners have a legal right to use water on their property. Property owners whose lands abut surface water bodies have a legal right to use water in adjoining water bodies subject to conditions and protections imposed on the use by MDE. Water appropriation and use permits are the mechanism to ensure that water use is managed appropriately and that adverse impacts are prevented.

The commenter provides no guidance on how large a river must be to allow a water withdrawal. A stream that is 10 feet wide, averages 6 inches deep and flows at 3 feet per second would carry about 9.7 million gallons of water per day. If an applicant requested to withdraw via a pump with a capacity of 500 gallons per minute, this request represents about 8 percent of the stream flow during the instant of withdrawal. Running the pump for about 6-7 hours per day for three weeks would provide about 4 million gallons of water.

Withdrawal permits from any stream or river require that a minimum flow be left in the river undisturbed. Maryland's methods for determining the flow-by for new withdrawals was not accurately described in the UMES-AL report. The required flow-by is a natural flow that has a statistical probability of being exceeded 85 percent of the time during the period of the use at the location of the withdrawal. During drought warning conditions (note, the drought warning trigger for streamflow is a streamflow that is exceeded between 90 and 95 percent of the time) withdrawals from a free flowing stream would be required to cease.

4. If there is a dry spell or water level decrease, the State should intermediately cut off the water supply for fracking until the supply is deemed sufficient. Constant monitoring should be done.

Permits for surface water withdrawal rely on long-term gage monitoring for determination if adequate water is present to support a withdrawal. See response above.

5. Given the massive amounts of water required to perform fracking, we wish to see recommendations limiting water withdrawals to areas where more than an "adequate reserve" is present such as reservoirs, lakes, and large rivers. "Adequate reserve" needs to be operationally defined, and we support the UMCES recommendation that MDE regulations be reviewed, and revised as necessary, regarding water withdrawal. Members of our Board have observed trucks illegally withdrawing water from Savage River, a premier brook trout stream, when water

levels have been very low. Current water appropriation regulations are insufficient to address this matter even without fracking. We recommend that MDE establish a citizen reporting program for water withdrawals, and funding for such an educational program must be budgeted, as well as additional MDE enforcers.

While a large quantity of water is needed for an individual fracking operation, the withdrawal may be spread out over an extended period of time and the rate of withdrawal within the range of a moderately large appropriation permit. While not generally recognized by the public, there is a much larger quantity of water stored in underground aquifers than in surface water bodies. If the upper 800 feet of aquifers in Garrett County contains fresh water and the average porosity of the consolidated sedimentary rocks is 5 percent by volume, then the amount of water stored in the aquifers in Garrett County is equivalent to a lake that is 40 feet deep over the full area of the County. This groundwater reserve represents about 55 billion gallons of water.

If Board members have observed what they believe to be illegal appropriations from trucks, such incidents should be reported to MDE's Water Supply Program. We appreciate the expression of support for additional MDE staff for compliance and enforcement duties.

6. Yet again the findings of UMCES-AL have been put aside by the BMPs. If the current water appropriation regulations are stringent enough then why would the study recommend that they be tightened?

The recommendation referred to is apparently "We found that Maryland's current oil and gas regulations governing permitting for conventional development require many of the elements that would be needed to properly address MSGD or unconventional development in general; however, the state should consider revising its oil and gas permitting regulations to explicitly address water withdrawal and storage issues, drilling waste and wastewater treatment and disposal issues, as well as transportation planning issues." The Department of the Environment has considered revising its regulations and determined, for the reasons stated in the response to comments, that revisions to water withdrawal regulations are not necessary, and that it is not necessary to include water withdrawal provisions in the oil and gas permitting regulations.

7. The study continues to rely on the Susquehanna River Basin Commission water appropriation methodology to determine if sufficient ground and water surface capacity exists in Allegany and Garrett Counties. There are significant differences between water availability in the Appalachian basin than the remainder of Maryland, and there may need to be changes in the Maryland appropriations process to more adequately establish a set of best management practices for Appalachian Maryland prior to allowing withdrawals for Marcellus gas drilling. Changes include but are not limited to permitting, reporting and monitoring by MDE personnel.

Existing water appropriation permitting law, regulation, and policy provide for different types of evaluation based on the location and hydrogeology of the proposed

withdrawal. Thorough hydrogeologic evaluation of permit requests is conducted, and ongoing reporting is required for all large permits. The appropriation program does rely on self-reporting, which has proven satisfactory in the past. If a more rigorous oversight program is desired, a source of funding to support additional staff and alternate methods of verifying water withdrawal information would be needed.

8. The Departments state that their requirements for water withdrawal permits are sufficiently robust and therefore will retain their current procedures for permitting water withdrawals. Water taken from local streams can jeopardize the habitat of fish as well as requirements needed for macroinvertebrates. These concerns for prudent water use sources are critical to the health of Maryland's coldwater resources. Given that the current procedure provide only limited public comment on water withdrawal permits would, if we requested a hearing for each application, become resource intensive and cumbersome as well as providing an additional source of public contention that could be avoided by developing large resource solutions for significant amounts of water needed over short time frames.

The Departments are aware of concerns about the impact of withdrawals on aquatic species. Conditions to limit intake velocities and require screening for surface water withdrawals are standard permit conditions for surface water withdrawals, along with limiting the withdrawal rate, and requiring a stream flow-by. It is correct that requesting a public hearing for each permit would require additional staff time and increase the permit processing time. It may be advantageous for regional withdrawal locations to be identified to limit the number and location of withdrawals. State law, however requires that all contiguous property owners for proposed withdrawals exceeding 10,000 gpd, as an annual average, be given an opportunity to comment on a requested water use.

9. Maryland's regulations for water withdrawal need to include a way to track cumulative effects of natural gas development on regional water resources.

When making a decision to issue or renew a water appropriation permit, the Department of the Environment considers the aggregate changes and cumulative impact that this and future appropriations in an area may have on the waters of the State, both surface water and groundwater. COMAR 26.17.06.05. Stream gages represent the best opportunity for quantifying the impact of withdrawals over a regional area. It may be necessary to install additional stream gages to appropriately quantify impacts of withdrawals. Reporting of water use is a standard condition of permits and the reported water use can readily be tabulated by use type and or location to determine withdrawal quantities for specific periods of time in different watersheds.

10. The requirement that all drilling related trucks be equipped with monitoring devices is an excellent idea. There must be official logging and storage of this data during the drilling operations so the data can be reviewed if there is a question of inappropriate water acquisition.

The draft best practices report made this recommendation with respect to trucks that were transporting liquid or solid wastes, not fresh water. Except for subdivisions served by individual domestic wells, a permit issued for an average of 10,000 or more

gallons a day must contain a condition requiring the permittee to report semiannually to MDE the quantity of water appropriated under the permit for each of the preceding 6 months. MDE may require a permittee to report daily use and may require the permittee to install flow-measuring devices. COMAR 26.17.06.06. MDE will consider including a permit provision requiring recordkeeping and reporting of fresh water transportation.

11. The regulation of water withdrawal strictly for human use may disregard the ecological flow requirements of species that occur in those waters. We would encourage MDE and DNR to review current policies and regulations to ensure that water withdrawals for HVHF also protect the ecological flow requirements of plant and animal species that use waters of the State that might experience HVHF.

Existing water appropriation laws, regulations, and policies already take into account water needs for aquatic habitat. Evaluation of groundwater withdrawals take into account baseflow needs for streams, and surface water permits include a requirement that withdrawals cease if flows fall below a specified level. Permits also include other conditions, such as requirements for screening of intakes, that are intended to protect aquatic species. MDE routinely provides DNR the opportunity to review and provide input on surface water permits. Identifying funding to continue and complete the Fractured Rock Water Supply study could provide additional information that would assist the Departments in making better decisions regarding permit requests.

12. As with transportation, the current API recommendations address water withdrawal and usage should be evaluated by the state in the development of final recommendations.

API Guidance Document HF2, Water Management Associated with Hydraulic Fracturing, would be considered a “relevant” API standard for purposes of the plans to be submitted with each individual well.

13. Fees and monitoring.

- a. The departments should adopt the water appropriations standards of the Susquehanna River Basin Commission (SRBC) for appropriations and fees. The SRBC fee structure allows for stream monitoring from areas where water withdraws are likely to impact water turbidity, ph, and temperature.
- b. There is no fee for a water appropriations request. However, this may prove to be a very time consuming endeavor for MDE, which may backlog the current 18-month turnaround for permits of over 10,000 gallons per day. Permit fees with the SRBC (which MDE partners with) allow for water monitoring from identified specific sites of surface water.

MDE agrees that imposing a fee for water appropriation permits would be appropriate. The fee structure needs to be based on Maryland’s needs and would not necessarily follow the SRBC model. Several bills have been proposed over the years to establish a fee system, but none passed. In addition, MDE has met with stakeholders to try to negotiate a fee structure that would be appropriate for all

users; however this effort has not met with any success or agreement from the stakeholders.

The fairly long time frame for issuing a large permit is primarily the time needed for the applicant to address the technical issues in the detailed permit application requirements. Addressing issues from the public can extend the time to complete a permit decision. Once instituted, a fee structure should not have any impact on the amount of time that it takes to issue a permit (unless the applicant is late in paying the fee.) Fee legislation would establish the purposes to which permit fees could be used.

14. Currently there are no provisions within the permitting structure to track water appropriations requests from parent companies, subsidiaries, or subcontractors for multiple permit requests.

While it's true that each water appropriation request is considered separately, MDE is currently in the process of developing a new data management system for water appropriation permitting that will allow the Department to better track related permits.

15. There is no provision for the multi-well CGDP process.

Water appropriation permits are issued separately from either CGDP approval or issuance of a permit for an individual well. The water appropriation application should identify the amount of water needed and the need for it. A water appropriation permit could be issued to supply water for multiple wells. The Departments plan to add a provision to the CGDP that would require the applicant to provide information on how it intends to acquire the necessary water.

16. Under the current system municipalities with a permit are not required to report to MDE withdrawals sold to companies for MSGD, as long as they do not exceed the permit threshold. This gap needs to be addressed to track cumulative effects of natural gas development on regional water resources.

The cumulative effect of water withdrawals on regional water resources is not tracked on an industry-by-industry basis. The water appropriation permit does not limit the permittee's ability to sell water, but upon permit renewal, or even earlier, MDE could reevaluate the permittee's allocation.

17. We support the Appalachian Lab report which recommended that Maryland revise its permitting regulations to address water withdrawal issues, by requiring withdrawals only from large rivers or reservoirs.

See previous answers.

18. Drilling companies should have to purchase the surface water used – much of this water does not return to the surface water cycle.

Before issuing a permit, MDE considers whether the water is returned to the watershed or used consumptively; however, there are currently no requirements that water users pay a consumptive water use fee. If a drilling company obtains water from a community water system, the company would likely pay a fee that is at least equivalent to the cost to the water system of producing the water.

19. The report should include a provision for encouraging usage of acidic coal mining discharges and or treated acid mine water for drilling purposes.

Existing water appropriation permit policies require certain applicants to evaluate the feasible use of alternate water sources before a groundwater withdrawal would be approved. This would apply to companies seeking to use water for hydraulic fracturing. Alternatives to encourage prior use of natural waters could include reuse of fracking water, using reclaimed municipal or industrial wastewater and acid mine drainage (AMD). There are liability issues related to the use of AMD which act as a disincentive to using AMD. In the future, the Department of the Environment may consider how it might address these liability issues.

20. If private wells run dry because water is taken for fracking, will those citizens be provided with potable water from deeper wells?

If the initial testing of a well for water production (as would be required during the application process for a large groundwater withdrawal) showed that a homeowner's well would be adversely impacted, such that it would no longer produce the needed quantity of water, then the applicant would be required to either locate the production well in a different location or improve the impacted supply before the applicant would be allowed to withdraw any water. Standard permit conditions would require a large groundwater user to cease pumping if their use caused a nearby well to run dry. Anyone impacted by another water user should notify the Water Supply Program immediately. An investigation would need to be initiated to determine if the lack of water from the well was from a lowered water level and not a defective pump or other mechanical/electrical issue. The permit would also require the permittee to provide at no expense to the homeowner an interim water supply and a permanent replacement water supply, if needed. It may be possible to alleviate an impact by reducing the withdrawal rate or by drilling a deeper well for the private well owner.

WELL CASING AND CEMENT

1. When wells or casings or cement fails, fracking fluid, flowback, and methane can be released. The following failure rates have been reported:
 - a. 5 or 6 percent of the time.
 - b. Industry studies find up to 60 percent will fail after 30 years.
 - c. PA reports a 7.2 percent failure rate.
 - d. EPA reports at 8.9 percent well casing failure rate for 2012, and a 7.1 percent failure rate in 2011 in Pennsylvania.
 - e. Maryland needs to find a way to adopt a standard that allows for 0 percent failure upon installation of casing.
 - f. The stats regarding casing failure show that currently zero leakage, which should be required but is not under the proposed BMPs, is impossible.

If the casing and cement fail to completely isolate a gas well from the formations through which it passes before reaching the target formation, gas can migrate from

intervening gas-bearing formations and can enter the environment, including drinking water aquifers. Not every failure of casing or cement results in a release of methane or other contaminants. For example, a tubing or packer leak inside of casing is technically a failure, but the pressure is still contained within the casing and no methane escapes from the well. Nevertheless, casing or cement failures should be avoided and, if they occur, promptly addressed.

Some of the best practices in the draft report are directed to assuring that the casing and cement will be properly installed and tested. These have been strengthened in the final best practices report by explicitly requiring that the applicant submit a plan that describes:

- a. how the a stable borehole will be drilled with minimal rugosity⁴⁰;*
- b. how complete removal of drilling fluid will be accomplished;*
- c. how the cement system design addresses challenges to zonal isolation; and*
- d. how the casing and cement assure durability throughout the well life cycle.*

This plan can be submitted with the permit application, but the permittee must review the plan in light of information obtained from the pilot hole drilled for that well pad, and certify to the Department of the Environment that the plan utilizes the right practices and materials for the specific situation to assure zonal isolation. Before commencing hydraulic fracturing, the permittee must certify the sufficiency of the zonal isolation with supporting data in the form of well logs, pressure test results, and other appropriate data. Adherence to the drilling, casing and cementing plan, coupled with integrity testing, should also address the possibility that releases of fracking fluid, flowback could occur because of casing or cement failure.

Although no activities can be guaranteed to have a zero rate of failure indefinitely and under all circumstances, the Departments are proposing standards that will drive down the failure rate and the consequences of any failure that may still occur. In addition, through review and approval of the plan, the Departments can require applicants to use better drilling, casing and cementing systems as they become available. 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.

2. The causes of well failure should be addressed

- a. We recommend that current industry standards be exceeded for pipeline construction and well casings. Maryland should either come up with best practices for minimizing the long-term degradation of the oil and gas industry's wells, or propose best practices for monitoring and resealing degraded wells.**

⁴⁰ Rugosity refers to the roughness of a borehole wall. Rugosity can be observed on caliper logs and image logs Source: Schlumberger Oil Glossary. High rugosity can make it more difficult to remove the drilling fluid and achieve zonal isolation with cement.

- b. The industry, in consultation with the Agencies, should be required to address the causes of casing integrity failure and to propose better practices that continually improve its standards for casing integrity.

As noted above, the applicant will have to design the casing and cement to assure durability for all anticipated conditions throughout the well life cycle. This will require consideration of changes in temperature and pressure, and the effect of refracturing the well and the installation and hydraulic fracturing of other wells on the same pad. By requiring detailed plans from the applicant, the Department of the Environment will require applicants to use better drilling, casing and cementing systems as they become available.

3. Companies should be required to run a test on every well to ensure adequate cementing, and inspections to ensure the compliance must be paramount if drilling is permitted.

The regulations will require testing of every well to ensure adequate cementing including cement testing, casing pressure testing, and cement placement verification. Permit fees will be set at a level that supports a rigorous inspection and enforcement program.

4. The recommendation calls for the production casing to be run the entire length of the well and cemented. This requirement does not appear to allow for the use of production liners and tie backs, and would also appear to require cementing the entire production casing back to surface. Requiring cementing of the entire production casing back to surface will create a number of design challenges that may actually reduce the effectiveness of the cement seal. Bringing cement from the total well depth back to surface could require the use of cements with very long fluid times (pump times) that would result in a delay of the set of the cement at the lower temperatures near surface. Cementing back to surface also eliminates the potential to monitor annular pressures between the production casing and intermediate casing, a needed safety measure during fracturing operations. The recommendation should clarify isolation in the production casing, allow for use of liner and tie back technologies, and better define what is meant by the statement referencing cementing.

The recommendation will be clarified. Liners and tiebacks may be used, provided the exposed casing meets all regulatory requirements for casing.

Surface casing must be set to a depth that isolates all freshwater formations and must be cemented to the surface. Intermediate casing, if used, must isolate all fluid bearing zones through which it passes. Intermediate casing, if used, must be cemented to the surface unless the Department of the Environment approves an alternative.

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 500 feet above the uppermost fluid bearing formation not already isolated by surface casing or intermediate casing, whichever is shallower. In this way, casing and cement will isolate all fluid-bearing (gas and liquid) formations through which the borehole passes before reaching the target formation, but it will be

possible to monitor annular pressure, which provides the operator with valuable information.

5. The recommendation is for the use of a segmented radial cement bond log (SRCBL) rather than the conventional omnidirectional cement bond log (CBL), but there is no statement regarding which casing strings would be required to be tested by SRCBL. This should be clarified. Further, there is no provision for the evaluation and analysis of the SRCBL, or who would determine the effectiveness of the cementing operation. It is noted there are no recommendations for capturing data during the cementing operation that would supplement the logging operation.

SRCBL will be required for all casing strings from the surface casing and below along the portions that are cemented. This can be supplemented by other methods, including omnidirectional cement bond logging and observations and measurements during cementing. If there is evidence of inadequate casing integrity or cement integrity, the Department of the Environment should be notified and remedial action should be proposed.

6. The incorporation of API Standard 65-2 would address cement evaluation in its full form, using surface data during the cement job, laboratory design data as well as post job logging information. The Standard correctly notes that one single data point (or data set) should be used to make the evaluation of cement isolation.

The draft best practices report stated that, in developing the plan for the individual well to submit with the application “the applicant shall consider API Standards and Guidance Documents, and, if the plan fails to follow a normative element of a relevant API standard, the plan must explain why and demonstrate that the plan is at least as protective as the normative element.” API Standard 65-2 would be considered a relevant API standard. The Departments acknowledge that evaluating zonal isolation and cement integrity requires the consideration of more than one type of data.

7. Maryland regulations should include more detailed requirements for timing of the casing construction so that the process and monitoring can be completed consecutively during one work shift. Reports from rig workers in Pennsylvania have stated that casing cure times have been shortened in order to accommodate work shift schedules, thus compromising the integrity of the cement strength.

It is not always possible to complete a stage of work within one work shift. For example, the draft best practices stated: “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.” Applicants for permits will be required to submit a communications plan that includes procedures to maximize continuity when shift changes or crew changes occur.

8. Maryland should forbid the use of reconditioned casing.

The Department of the Environment will allow use of reconditioned casing only if it meets required technical specifications.

9. The method for testing the cement for compressive strength of 500 psi within 12 hours should be specified.

API Recommended Practice 10B-2, Recommended Practice for Testing Well Cements would be considered a relevant API standard. Any recognized method, such as ASTM C 109, Standard test method for compressive strength of hydraulic cement mortars (using 2 in. or [50 mm] cube specimens), would be acceptable.

10. When a log (e.g., SRCBL) shows a failure, corrective action should be specified.

The Departments acknowledge that evaluating zonal isolation and cement integrity requires the consideration of more than one type of data. If there is evidence of inadequate casing integrity or cement integrity, the Department of the Environment must be notified and remedial action must be proposed. The type of corrective action cannot be identified in advance because the appropriate corrective action will depend on the location and magnitude of the failure.

APPENDIX D – MARCELLUS SHALE CONSTRAINT ANALYSIS

This analysis was conducted by the Maryland Department of Natural Resources to estimate the potential effect that certain surface and subsurface constraint factors would have on the ability to access Marcellus shale gas deposits. The Department understands that there are many other additional factors that would also have an influence. This estimate is to be used only as a preliminary assessment.

Surface and Subsurface Constraint Factors: Factors selected were those that support a landscape scale analysis and were determined to be reasonable based on joint DNR/MDE review of recommendations provided by UMCES. Fine-scale features, such as caves, the down-dip side of limestone outcrops and private drinking water wells, were not selected because complete data sets were not available. In addition, constraints associated with these factors will be most relevant at a field scale site assessment.

Off-Limit Areas	Setback/Buffers	Type
Aquatic habitat <ul style="list-style-type: none"> • streams, rivers, seeps, springs • wetlands, lakes, ponds, reservoirs • 100 year floodplains 	450 feet	Surface
Special conservation areas <ul style="list-style-type: none"> • Wildlands • Irreplaceable Natural Areas 	600 feet	Surface
Cultural, historical and recreational areas <ul style="list-style-type: none"> • National Registry sites • State and Federal Parks • Trails • Wildlife Management Areas • Scenic and Wild Rivers • Scenic Byways 	300 feet	Surface
All Other DNR Public Lands <ul style="list-style-type: none"> • State Forests • Natural Resource Management Areas • Others 	0 feet	Surface
Deep Creek Lake	2,000 feet	Surface

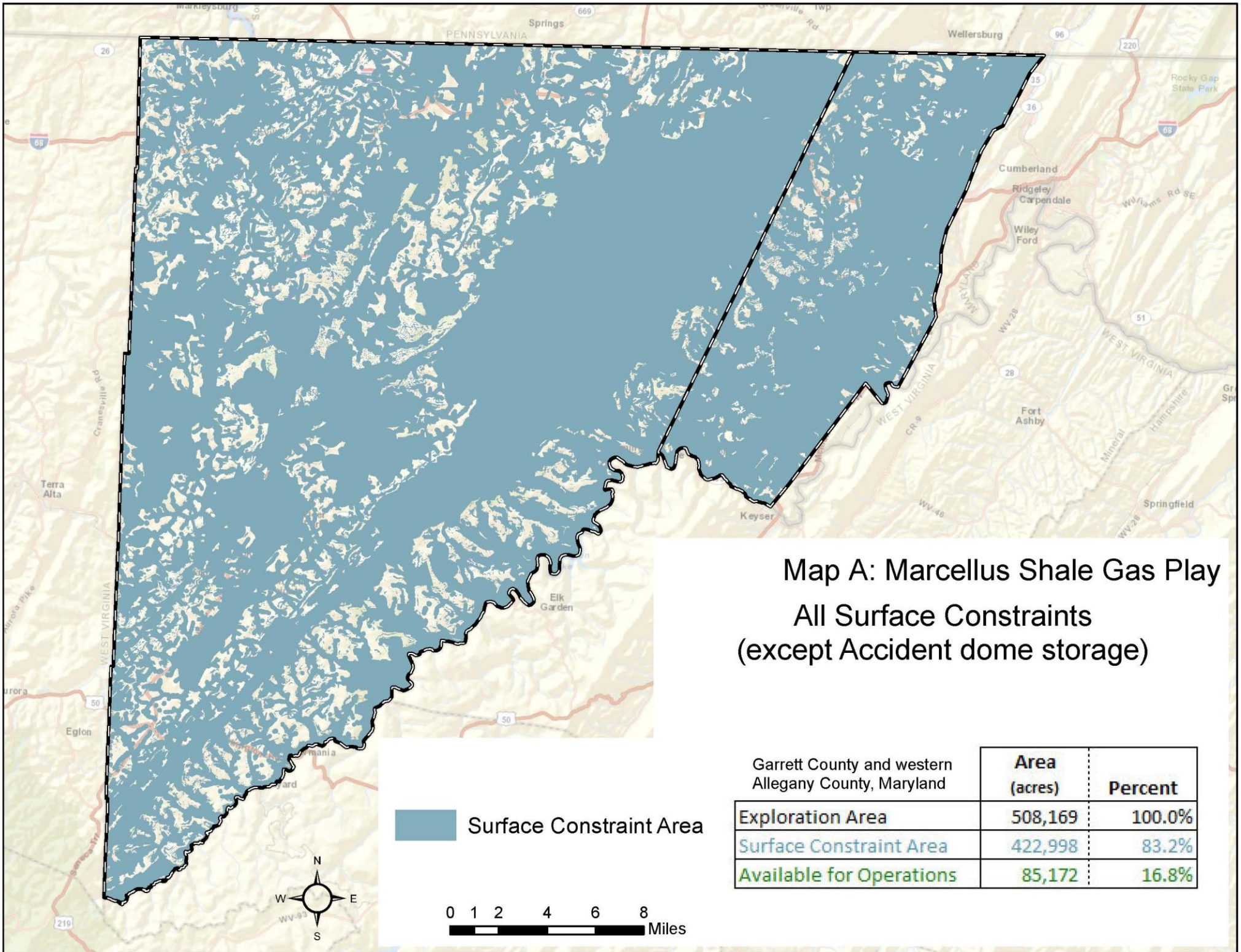
Low, Medium and High Density Residential and Institutional Uses (MDP 2010)	0 feet	Surface
Accident Dome Gas Storage Field	0 feet	Subsurface
➤ 15 percent slopes (UMCES)	0 feet	Surface
Drinking water reservoir watersheds (Broadford Lake, Piney Reservoir, Savage Reservoir)	0 feet	Surface
Wellhead protection area or source water assessment area for a Public Water System	1000 feet	Surface

Map A identifies the areas constrained from surface development and shows only the surface constraints. These surface constraints (without any prohibition of well pad development over the Accident Gas Storage field) remove 83.2 percent of the land surface within the Garret and Allegany county Marcellus Shale exploration area from surface development, leaving 16.8 percent of the land area available. Map B shows the same information, but also includes the constraints on well pad development over the Accident Gas Storage Field. With the constraints associated with the Accident Field, 84.7 percent of the land surface is removed from development, leaving 15.3 percent of the exploration area available for surface development.

Subsurface Access Analysis

Based on the surface constraints identified above, the ability to access Marcellus shale gas deposits through horizontal drilling was evaluated based on the UMCES statement that each well could be drilled horizontally a distance of 8,000 feet. The analysis also assumed that an average of 4 acres would be required for a multi-well pad based on industry estimates published in the [New York Revised Draft Supplemental Generic Environmental Impact Statement \(2011\)](#).⁴¹ Any areas less than 4 acres that remained suitable for surface development were removed from the analysis since these locations would not be large enough to support a pad. The remaining areas were buffered by 8,000 feet in order to determine the extent of Marcellus shale that was accessible. Map C, which does not restrict access to the Accident Gas Storage Field shows that 94.1 percent of the Marcellus shale can be accessed under this constraint analysis. A more conservative analysis, using a 4,000 foot horizontal length, could provide access to 86.3 percent of the Marcellus shale. Map D provides a similar assessment, but does restrict access to the Accident Gas Storage Field. Under this scenario, considering an 8,000 foot horizontal drill length, 88.0 percent of the Marcellus shale is accessible, while 80.2 percent is accessible using 4,000 foot horizontal drill length assumption.

⁴¹ www.dec.ny.gov/energy/75370.html.



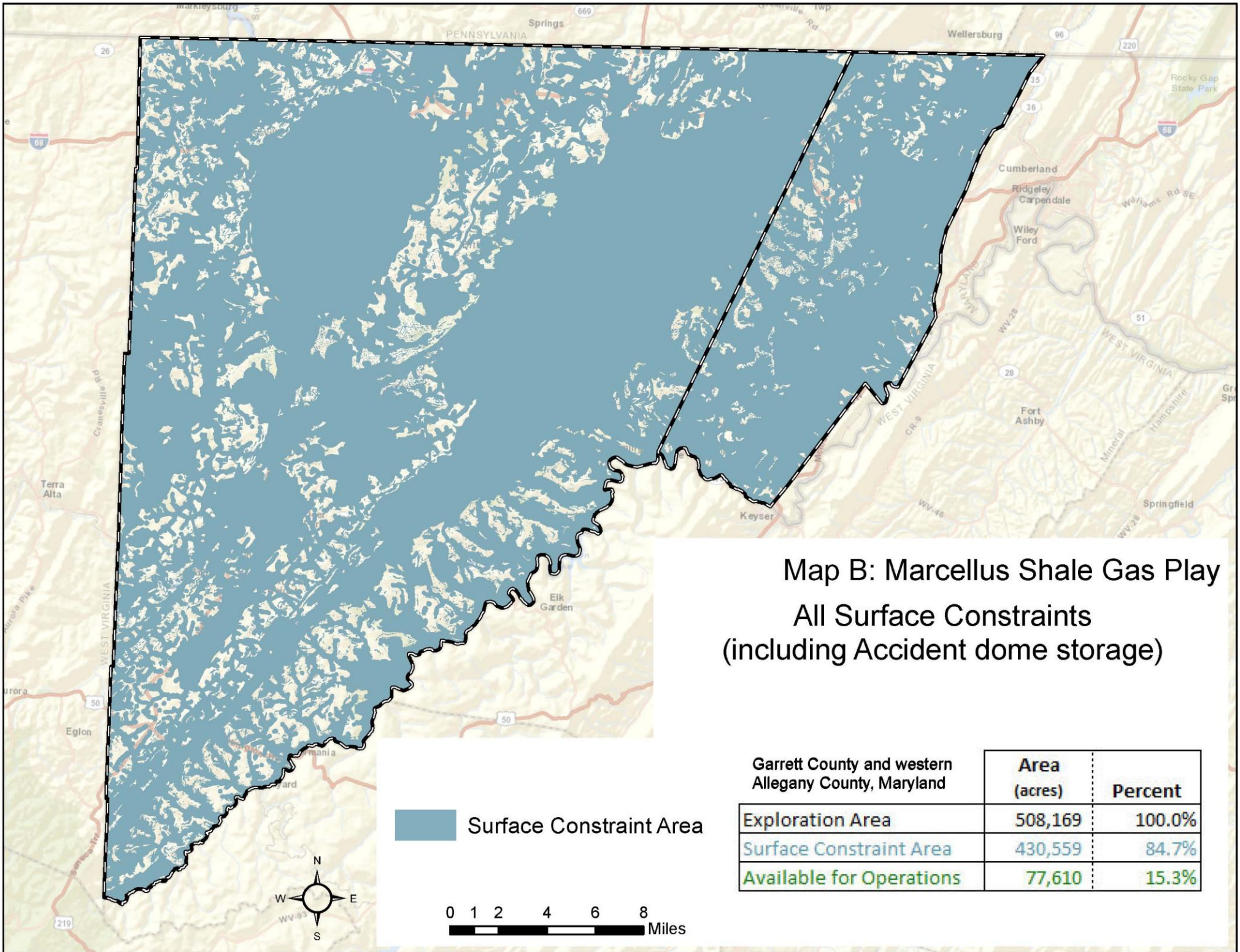
**Map A: Marcellus Shale Gas Play
All Surface Constraints
(except Accident dome storage)**

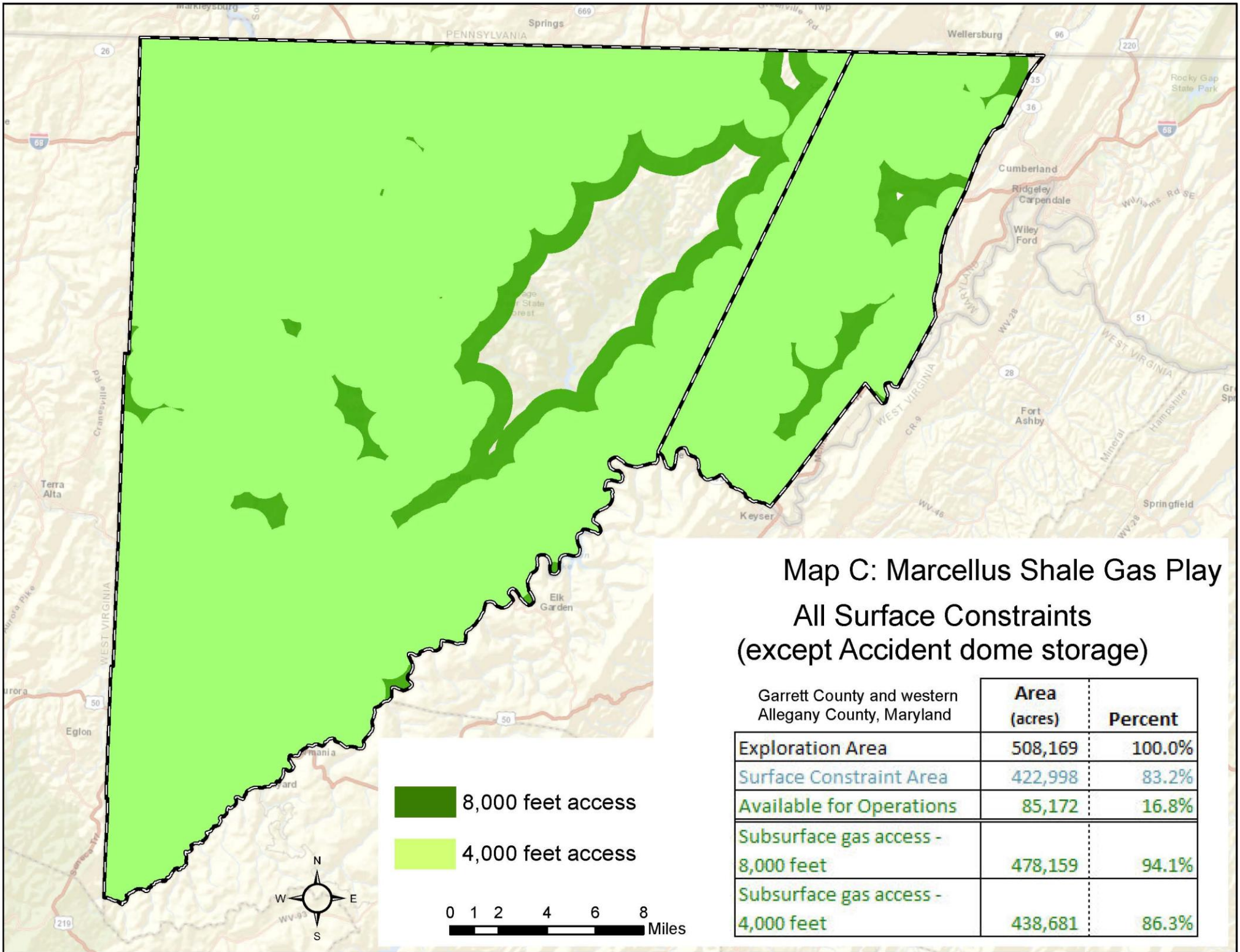
Garrett County and western Allegany County, Maryland	Area (acres)	Percent
Exploration Area	508,169	100.0%
Surface Constraint Area	422,998	83.2%
Available for Operations	85,172	16.8%

 Surface Constraint Area



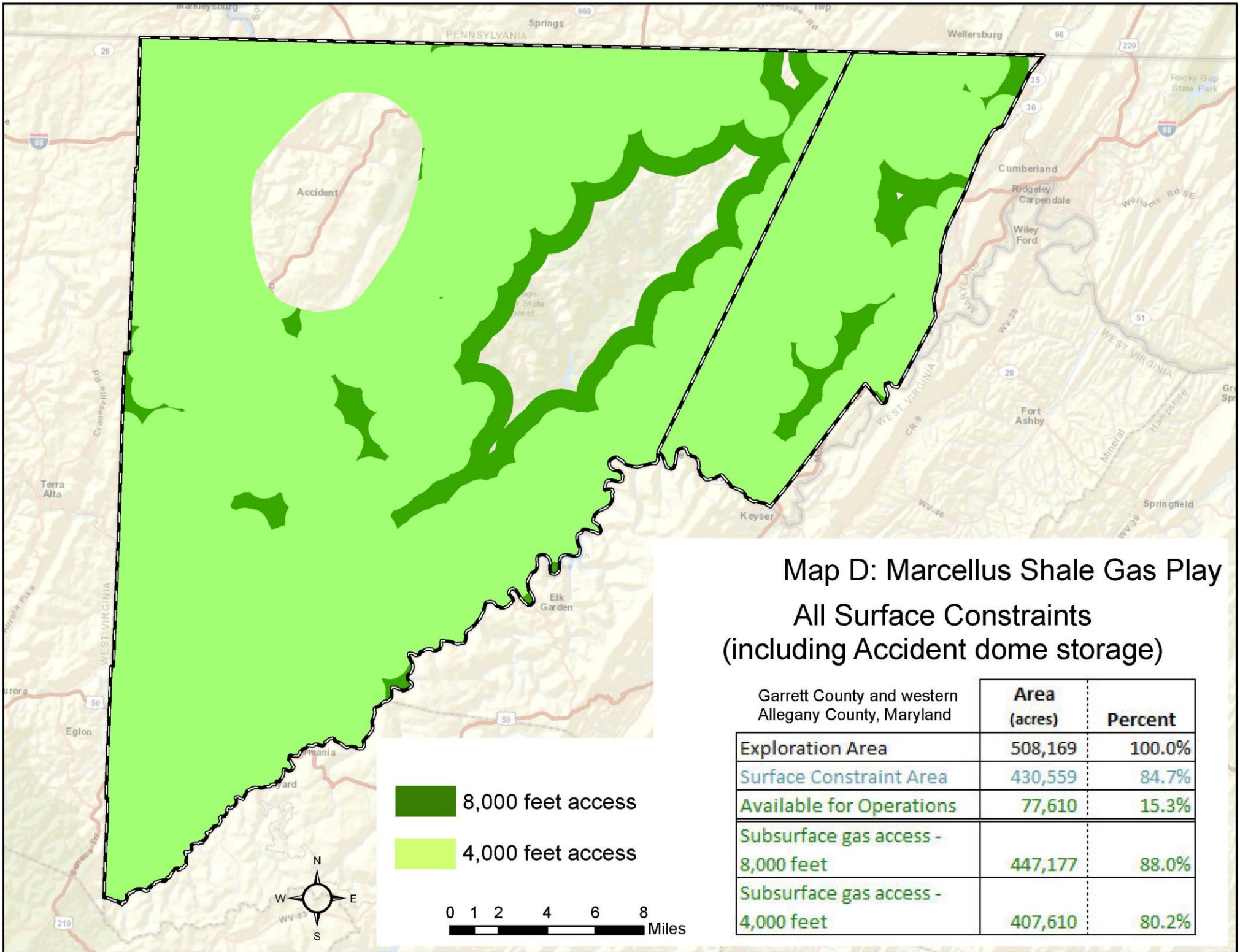
0 1 2 4 6 8 Miles





**Map C: Marcellus Shale Gas Play
All Surface Constraints
(except Accident dome storage)**

Garrett County and western Allegany County, Maryland	Area (acres)	Percent
Exploration Area	508,169	100.0%
Surface Constraint Area	422,998	83.2%
Available for Operations	85,172	16.8%
Subsurface gas access - 8,000 feet	478,159	94.1%
Subsurface gas access - 4,000 feet	438,681	86.3%



APPENDIX E – MARCELLUS SHALE AND RECREATIONAL AND AESTHETIC RESOURCES IN WESTERN MARYLAND

Marcellus Shale, State Lands and Economic Impacts of Parks

Maryland’s Western Region is rich in recreational, cultural and aesthetic resources. Garrett and Allegany Counties are home to eight State Parks; one Natural Resources Management Area (NRMA); one Natural Environment Area (NEA) – the State’s only designated wild river, four State Forests; four Wildlife Management Areas, three fish hatcheries/fish management areas, six Heritage Conservation Fund sites, one undesignated conservation area (MET), two scenic byways; miles of trails and a number of developed or developing water trails. Western Maryland has high public land visitation by both day use and overnight users. The development of a Marcellus shale gas industry in western Maryland has the potential to affect visitor’s experiences, alter the recreational and aesthetic landscape of the region, negatively affect longstanding research and resource management sites and change the economic impact of park visitation in the future.

The Maryland State Parks are an economic driver for local communities and areas around the parks ([Dougherty, 2011](#))⁴². Of the four park regions in the State, those in the Western region experience the highest overall economic benefit both in terms of direct spending and total economic impact that considers indirect and induced effects (Figure 1, below). State Park visitors in the Western region directly spend more than \$211 million annually during their trips. The Western region also experiences the second-highest employment impact as a result of parks by supporting 2,775 direct jobs related to park visitation. *Id.*

<u>Region visited</u>	<u>Direct Spending</u>		<u>Total Economic Impact including indirect/induced effects</u>	
	in MD	within a 20 minute drive	in MD	within a 20 minute drive
Western	\$211,407,422	\$152,722,509	\$239,273,592	\$169,903,045
Central	\$74,297,143	\$53,910,981	\$86,879,793	\$64,157,303
Southern	\$76,994,613	\$50,530,556	\$88,065,924	\$56,798,719
Eastern	\$204,743,180	\$140,054,190	\$236,445,765	\$159,830,604

Figure 1. Total trip spending profile by region (Dougherty, 2011)

⁴² www.dnr.state.md.us/publiclands/pdfs/economicimpactstudy2010.pdf.

Open Space Experience

In the same Economic Impact Study (Dougherty, 2011), natural scenery was the most highly rated attribute of a Maryland State Park experience for both day use and overnight park visitors. The majority of activities that both of these user communities identified as activities that they participate in at parks include hiking/walking, general relaxation, swimming, picnicking/cookout, sightseeing and photography.

Byways, Hiking, Water Trails, Hunting and Fishing

Maryland has a number of well-developed and nationally-recognized networks of scenic and historic byways and hiking and water trails that provide opportunities for the public to experience nature, cultural and historical features and the outdoors through unique vistas and long-distance travel routes. The location and features that make these routes unique (*e.g.* vistas, through-trail hikes, canopy cover) should be considered during setback discussions.

In addition to vast scenic values and hiking and water-based recreation, there are also many opportunities for citizens to enjoy hunting and fishing on public lands in Western Maryland. Especially for these groups, noise and other possible environmental effects from drilling and operations can impact the quality or feasibility of these activities. If wildlife is impacted or frightened away from a particular area, the potential exists for the activity to be dislocated entirely.

Recommended Setbacks and Considerations

Currently, a proposed recreational setback from Marcellus shale gas infrastructure is a minimum of 300 feet with additional setback considerations for noise, visual impacts and public safety. In addition to these considerations odors, light and illumination from the same infrastructure can also affect the natural and recreational values of areas of Western Maryland.

Discussions with Maryland Department of Natural Resource (DNR) staff related to these additional considerations, have identified several factors that may influence where this minimum setback should be increased, in some cases significantly. For instance, additional consideration and thought should be given for whether this setback should be altered based on the following:

- whether the facilities at sites are concentrated or more spread out;
- locations of high-use where visitors, managers and community members identify as most heavily trafficked or utilized;
- the presence or absence of natural buffers that could buffer sound, light and odors, especially at night, and near campgrounds;
- areas where reduced-light recreation activities occur;
- areas where particular trails are most frequently identified as providing a peaceful experience and that may be most affected by shale gas operations noise;
- lands or aquatic areas where natural resources may be degraded to a point that park visitation for the purpose of enjoying those resources would no longer be attractive;

- hunting areas that could be affected by access or operations noise and/or locations where proximity to shale gas infrastructure would increase risk to site operators/operations;
- whether unique designations are in place (*e.g.* Wild and Scenic Rivers) that define an experience in a particular location or influence funding; and
- instances where public safety risks on or around State lands would be most likely to be increased on roads, day use or overnight accommodation areas or in surrounding areas as a result of close proximity of infrastructure and people.

To more thoroughly evaluate each of these and identify particular areas that may most need additional setback consideration, work could be conducted with facility managers, friends groups or small groups of frequent visitors to compile existing data and develop new maps of use areas. In addition, some of these considerations could be considered on a case-by-case basis during the siting process to determine their applicability and evaluate what recreational or aesthetic uses that might be affected in a given area.

Night Skies

In Pennsylvania, where the Marcellus shale gas industry is much more developed, efforts are underway to document the relationship between lighting on these industrial sites and changes in the darkness of night skies. In particular, a group is working at Cherry Springs Park in Potter County to document the proximity of the lights and potential impacts on dark skies. In areas where there are dark night skies in western region State lands and where reduced-light recreation activities occur, work should focus on how to keep those night skies as dark as possible. Information and lessons learned can also be gleaned from efforts such as the one that is ongoing in Cherry Springs.

Outreach & Community Engagement

Over the past five years or more, property owners and communities in western region counties have become increasingly familiar with the development of the Marcellus shale gas energy industry. In some cases, property owners have entered into lease agreements with development companies for gas extraction. Since Maryland established its Marcellus Shale Advisory Commission the public has had a periodic forum to learn what the State is doing to plan for industry development; evaluate potential community, economic, infrastructure, and natural resource impacts; and, set up a regulatory framework to ensure safe and efficient development of the industry in Maryland.

State agencies and other partners have developed a number of resources to help citizens better understand Marcellus shale gas site development. These include [information](#)⁴³ from the Maryland Geological Survey, MDE's Marcellus shale [website](#)⁴⁴ and [publications](#)⁴⁵ from the Office of the Attorney General. The Maryland Department of Natural Resources has extensive experience in public engagement on a variety of issues and can recommend forum structures, information format and organizational approaches for such events.

⁴³ www.mgs.md.gov/

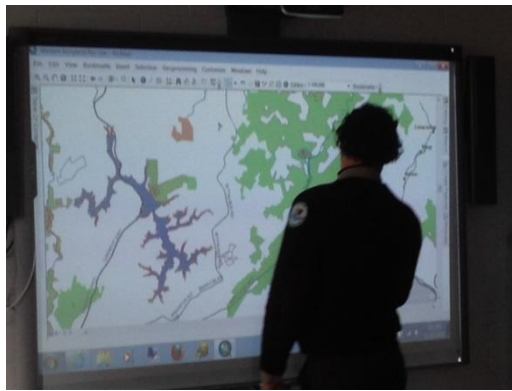
⁴⁴ www.mde.state.md.us/programs/Land/mining/marcellus/Pages/index.aspx

⁴⁵ www.oag.state.md.us/Environment/MS_leasing.pdf

The November 2013 Participatory GIS Workshop

On November 15, 2013 a participatory mapping workshop was conducted at Garrett College to identify particular areas where recreational and aesthetic impacts would most likely intersect with the expansion of the shale gas industry. The individuals invited to attend were those engaged in some aspect of outdoor recreational use, either as a business (tour guides, outdoor recreational services and retail), non-profit (birding, hiking, environmental or other organizations), educational, or DNR public lands representatives (rangers, park managers, Natural Resource Police).

These individuals were asked to work together and collectively map out areas within Garrett and Allegany counties that were important for a variety of recreational uses. Recreational use categories included 1) Recreational Guided and Outfitted Uses, 2) Recreational Fishing and Hunting Uses, and 3) General Non-consumptive Recreational Uses, such as boating, hiking, biking, etc. The exercise required participants to use a large digital projection screen and digital pen to map out areas of high use according to specific recreational uses as shown below.



The products from this mapping workshop are still under DNR review as of June 2014 and will be distributed to the participants for additional revisions if needed before the maps are finalized. These mapping products will be included in the Shale Gas Development Toolbox to be used during the Comprehensive Gas Development Planning process in order to minimize public use conflicts resulting from shale gas development.

APPENDIX F – UMCES-AL REPORT AND CROSS REFERENCES

The UMCES-AL Report can be found at http://www.mde.state.md.us/programs/Land/mining/marcellus/Documents/Eshleman_EI_more_Final_BMP_Report_22113_Red.pdf

Recommendations from the UMCES-AL Report with Analogous Provisions of Draft Agency BMP Report

Chapter 1 – General, planning and permitting BMPs

UMCES-AL	MDE and DNR
<p>1-A Pre-development environmental assessment should be conducted on a site-specific basis and include: (1) identification of all on-site drilling hazards such as underground mine workings, orphaned gas or oil wells, caves, caverns, Karst features, etc.; (2) identification of all ecological, recreational, historical, and cultural resources in the vicinity of a proposed site (includes well pad and all ancillary development such as cleared areas around a well pad, roads, bridges, culverts, compressor stations, pipelines, etc.); (3) identification of the appropriate setbacks and buffers for the proposed site; and (4) collection of two years of pre-development baseline data on underground drinking water, surface water, and both aquatic and terrestrial ecological resources.</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation. Some of the data will be required for the CGDP; other data in applications for individual permits. This recommendation is also reflected in Sections V, Plan For Each Well and VII, Monitoring, Recordkeeping and Reporting.</p>
<p>1-B Maryland should require as part of its permit application at least two years of site specific data collection prior to any site development that would be used to characterize the resources at risk and provide a solid baseline dataset that would ultimately be used to understand process and feedback to the refinement of BMPs.</p>	<p>Section VII, Monitoring, Recordkeeping and Reporting adopts this recommendation and adds that characterization and monitoring data will be important to identify whether any impacts to the resources has occurred, and can be used as basis for mitigating damage.</p>
<p>1-C Comprehensive planning (a.k.a., comprehensive drilling plans) could potentially be used to effectively channel MSGD into areas that would be less sensitive to impacts while allowing for considerable and efficient exploitation of the gas</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation; however, limiting the disturbance to 1-2 percent of the land appears as a planning principle for high</p>

<p>resource. Spacing multiwall pads in clusters—as far apart as is technically feasible—makes maximum use of horizontal drilling technology and could be an important BMP in terms of minimizing development impacts. With careful and thoughtful planning (<i>e.g.</i>, co-location of infrastructure wherever possible), it may be possible to develop much of the gas resource in a way that disturbs less than 1-2 percent of the land surface, even when accounting for the need for ancillary infrastructure such as access roads, pipelines, and compressor facilities. Comprehensive gas development plans could also moderate the rate at which the resource is developed in Maryland, thus allowing the regulatory enforcement arm of MDE (with little recent experience in gas well permitting and no experience in unconventional gas) to ramp up over time.</p>	<p>value watersheds and the Departments do not recommend using CGDPs to limit the pace of development.</p>
<p>1-D Maryland should consider legislation that would enable the state to implement “forced pooling” as a way of providing greater resource protection while allowing for efficient resource exploitation.</p>	<p>Section VIII C, Miscellaneous Recommendations. The Departments recommend that forced pooling not be considered at this time.</p>
<p>1-E Maryland should impose by regulation sensible setbacks (see Table 1.1) that are adequate to protect public safety, as well as ecological, recreational, historical, cultural, and aesthetic resources.</p>	<p>Section IV A, Location Restrictions and Setbacks. The Departments generally accept the proposed location restrictions and setbacks with the exceptions noted. The Departments reduced the suggested setback from limestone outcrops, increased the setback from aquatic habitats, private ground water wells, public water systems and reservoirs, excluded development on all DNR public lands, and require pre-drilling planning including geologic investigations and use of pilot holes to evaluate subsurface hazards, such as deep coal mines, gas wells, faults, etc.</p>
<p>1-F There is a definite need for an analysis of extant hydrogeological data from western Maryland that could be used to develop flow nets or models and infer ground water flowpaths and other important features such as recharge areas, discharge areas, hydrologic residence times, and depth of the freshwater zone across the area.</p>	<p>The Departments, with the help of Garrett County, have begun to assemble the existing data on drinking water wells in Garrett County and undertaken additional ground water sampling.</p>

<p>1-G Maryland might consider developing a standardized stakeholder process that could be implemented as part of comprehensive planning strategy; the goal of such a process while allowing the permit review process to be expedited.</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.</p>
<p>1-H We recommend that Maryland follow guidance from New York’s experience with unconventional shale gas development and effectively not permit MSGD (or any other unconventional gas development) where the target formation occurs within 1,000 vertical feet of USDW or within 2,000 vertical feet of the ground surface. Since the freshwater/saltwater interface has not been mapped in Maryland, the prudent approach would be to rely on the 2,000 ft criterion to provide an adequate margin of safety.</p>	<p>This recommendation is accepted in Section IV A, Location Restrictions and Setbacks.</p>
<p>1-I An obvious best practice would be to site well pads so as to avoid vertical drilling (<i>i.e.</i>, surface boreholes) in areas where shallow caves and caverns have been mapped or where there is a high probability that such systems might be present. Maryland should develop a GIS map system of both active and abandoned oil and gas wells (including gas storage wells) and active and abandoned coal mine workings prior to permitting any new Marcellus wells; all underground hazards with ¼ mile of any section of a proposed Marcellus well should be identified as part of the permit review process and avoided wherever possible.</p>	<p>Section IV A, Location Restrictions and Setbacks. The Departments generally accept the proposed location restrictions and setbacks recommendations and will develop a Shale Development Toolbox to provide a comprehensive set of GIS planning data, including known and mapped locations of the features listed in this recommendation.</p>
<p>1-J Maryland should require a 1,000 ft setback from all deep mine workings and ¼ mile setback from all historic gas wells. The gas well setback should be measured from any portion of the borehole (vertical or horizontal) to the historic well.</p>	<p>Section IV A, Location Restrictions and Setbacks. The Departments recommend reducing the 1,000 ft setback from deep mine workings as it is unnecessarily restrictive since Maryland’s deep coal mines may cover thousands of acres, are only several hundred feet deep, and can be safely cased through, particularly if pilot holes are drilled to identify these features and drilling processes are modified to address the known hazards. Section VI D, Engineering, Design and Environmental Controls and Standards require pre-drill planning to plan for and avoid, if necessary, subsurface hazards</p>
<p>1-K Maryland should develop regulations that</p>	<p>Section VI R, Engineering, Design and</p>

<p>force rapid partial reclamation (including revegetating disturbed areas surrounding wells pads, corridors, and ancillary infrastructure) of all land not needed for drilling and production as quickly as possible, while allowing the remaining portion to exist unreclaimed only until such time as drilling is completed, production ends, and final reclamation can be performed.</p>	<p>Environmental Controls and Standards adopt this recommendation</p>
<p>1-L We found that Maryland’s current oil and gas regulations governing permitting for conventional development require many of the elements that would be needed to properly address MSGD or unconventional development in general; however, the state should consider revising its oil and gas permitting regulations to explicitly address water withdrawal and storage issues, drilling waste and wastewater treatment and disposal issues, as well as transportation planning issues.</p>	<p>MDE considered the need to revise the oil and gas permitting regulations. Recommendations for changes can be found throughout Section VI, Engineering, Design and Environmental Controls and Standards.</p>
<p>1-M Local zoning ordinances for both counties should be amended to spell out in which zoning districts MSGD would be permitted as a way of minimizing some of the major conflicts and public safety issues that we addressed in this report.</p>	<p>Section VIII A, Miscellaneous Recommendations. Zoning is a local matter over which the State has no control. The Counties are well aware of their authority to enact zoning regulations.</p>
<p>1-N Maryland’s requirements for performance bonding under current regulations (\$100,000 per well or \$500,000 blanket bond for all of an applicant’s wells) are relatively high compared to other states; thus, the state might be to avoid some of the problems associated with divestment of MSGD assets from primary to secondary firms that are predicted as gas production declines. Nonetheless, Maryland might want to consider alternate mechanisms of covering decommissioning and reclamation costs through a trust fund mechanism (<i>i.e.</i>, investing revenue from pre-drilling fees and a five-year severance tax on production) as an alternative to performance bonding.</p>	<p>Section VIII B, Miscellaneous Recommendations. Financial assurances and the concern about divestment were appropriately addressed in the 2013 legislative passage of SB854, sponsored by Senator Edwards, providing financial assurance for gas and oil drilling.</p>

Chapter 2 – Protecting Air Quality

<p>UMCES-AL</p>	<p>MDE and DNR</p>
<p>2-A Require that operators in Maryland establish a methane leak detection and repair program that governs operations from wellhead to</p>	<p>Leak Detection is required in Section VI L, Engineering, Design and Environmental Controls and Standards, and operators will</p>

<p>the transmission line, regardless of whether processing plants are necessary. All operators in Maryland should voluntarily participate in USEPA’s Natural Gas STAR program aimed at implementing cost-effective strategies for reducing methane emissions by the industry.</p>	<p>need to meet monitoring, reporting and recordkeeping requirements as referenced in Section VII, Monitoring, Recordkeeping and Reporting.</p> <p>No State action is necessary to allow operators to voluntarily participate in EPA’s Natural Gas STAR program. Rather, MDE will require Top-down Best Available Technology (BAT) to manage air emissions as referenced in Section VI J, Engineering, Design and Environmental Controls and Standards</p>
<p>2-B Encourage operators to either use newer internal combustion engines or convert from diesel internal combustion engines to electric motors for operating drilling rigs, pumps, and compressors wherever possible by implementing “fleet average” emission standards for NO_x, VOCs, and PM_{2.5}.</p>	<p>Section VI E and J, Engineering, Design and Environmental Controls and Standards, accepts this recommendation.</p>
<p>2-C Require monitoring of hazardous air pollutants at well pad sites.</p>	<p>Section VII, Monitoring, Recordkeeping and Reporting, accepts this recommendation.</p>
<p>2-D Monitor gamma and alpha radiation of production brines.</p>	<p>Section VII, Monitoring, Recordkeeping and Reporting, accepts this recommendation.</p>
<p>2-E Implement an air emissions monitoring program throughout the region, focusing on sources and fugitive sources of pollutants (and pollutant precursors) at well pads and at other sources resulting from natural gas production.</p>	<p>Section VII, Monitoring, Recordkeeping and Reporting, accepts this recommendation.</p>

Chapter 3 – Well engineering and construction practices to ensure integrity and isolation

<p>UMCES-AL</p>	<p>MDE and DNR</p>
<p>3-A A best practice for anyone proposing to operate in Maryland should be adoption of API’s extensive guidelines for well planning—at least those elements that are clearly relevant to onshore development. Pre-permit site review should also be required.</p>	<p>Section V, Plan For Each Well, accepts this recommendation.</p>

<p>3-B Site selection is a critical aspect of well planning for multiple reasons discussed throughout the report. As discussed in Chapter 1, we are particularly concerned about drilling in areas where there is a high probability of encountering large underground voids (<i>e.g.</i>, caverns, caves, mine workings, abandoned wells, etc.) that have the potential to cause a loss of fluid circulation during drilling and impose additional risks during the cementing process. Such hazards are locally common in western Maryland and we recommend that sites with a high probability of encountering such hazards be avoided.</p>	<p>Section IV B, Location Restrictions and Setbacks. The Departments generally accept the proposed siting best practices recommendation and note that certain known hazards can be addressed through modified drilling processes.</p>
<p>3-C Surface casing must be fully cemented from the bottom to the surface to provide total protection of all USDW. There may be situations (<i>e.g.</i>, very deep wells) where fully cementing the intermediate casing to the surface may not be required, however. At a minimum, an absolute requirement should be that all flow zones (including USDW) must be fully protected through the use of cemented intermediate well casings. Where this cannot be accomplished feasibly with a single casing string, the use of multiple casing strings should be favored in the well design.</p>	<p>Section VI F, Engineering, Design and Environmental Controls and Standards, accepts this recommendation.</p>
<p>3-D Maryland should consider amending its regulations to require SRCBL (or equivalent casing integrity testing) and other types of logging (<i>i.e.</i>, neutron logging) as part of a cased-hole program.</p>	<p>Section VI F, Engineering, Design and Environmental Controls and Standards, accepts this recommendation.</p>
<p>3-E Best practice would clearly call for use of pressure testing of Marcellus shale gas wells in Maryland, with specific criteria and technical details governing the conduct of such tests likely established through consultation with industry. Maryland's current regulations with regard to pressure testing of cemented casings are even less specific than those established by neighboring states and appear to be in need of revision.</p>	<p>Section VI F, Engineering, Design and Environmental Controls and Standards, makes recommendations for mechanical and pressure testing.</p>
<p>3-F Use of BOPE with two or more redundant mechanisms should be considered a best practice for MSGD in Maryland.</p>	<p>Section VI G, Engineering, Design and Environmental Controls and Standards, accepts this recommendation.</p>
<p>3-G We recommend that a sufficient number of tiltmeter or micro-seismic surveys be performed as part of any MSGD in Maryland, so that the extent,</p>	<p>Section VI H, Engineering, Design and Environmental Controls and Standards, and Section VII, Monitoring,</p>

<p>geometry, and location of Marcellus fracturing can be adequately characterized across the entire region. The principal goal of this effort would be to feed useful information back to the operators, so that subsequent hydraulic fracturing can be conducted more safely and effectively. Data from such surveys in Maryland (and other states) would also be deemed crucial in evaluating whether HVHF might eventually be safely conducted in locations where the target formation is located within 2,000 ft of the surface.</p>	<p>Recordkeeping and Reporting, accept this recommendation.</p>
<p>3-H Maryland also has what appear to be excellent regulations that are consistent with API recommendation for plugging of wells. Given the long expected time lags (of the order of 30 years) between drilling and well decommissioning, the biggest problem that we anticipate with plugging of Marcellus wells in Maryland will be establishing liability and ensuring that liable parties can be held accountable for performing this critical task. The costs associated with plugging wells that were poorly constructed in the first place can be extremely high, which reinforces the need to ensure that any Marcellus shale gas wells in Maryland are constructed to the highest standards.</p>	<p>The report makes many recommendations for ensuring that any Marcellus shale gas wells in Maryland are constructed to the highest standards. In addition, financial responsibility for closure was appropriately addressed in the 2013 legislative passage of SB854, sponsored by Senator Edwards (Section VIII B, Miscellaneous Recommendations)</p>

Chapter 4 – Protecting water resources

<p style="text-align: center;">UMCES-AL</p>	<p style="text-align: center;">MDE and DNR</p>
<p>4-A A best practice for Maryland would be establishment in regulation of 500 ft. and 2,000 ft. setbacks (measured from the well pad, not from the individual wellbores) for private wells and public system intakes (both surface and ground water), respectively.</p>	<p>Section IV A, Location Restrictions and Setbacks. The Departments accept the proposed 2,000 ft setback from public wells, and note that current regulations (COMAR 26.19.01.19G) already provide a 1,000 ft setback from all drinking water supplies, which includes private wells. Additional considerations to setbacks from private and public drinking water systems are referenced in Section IV A, Location Restrictions and Setbacks</p>
<p>4-B We support Maryland Environmental Code § 14-110.1 (H.B. 1123) and recommend predevelopment notification should be made to public and private drinking water well owners.</p>	<p>Current Maryland regulations require that the applicant identify all water wells within 2,650 feet of the proposed well location. The Department must mail written notice of the decision to grant or deny the permit to all landowners within</p>

	1,000 feet of the proposed well. Section V, Plan for Each Well, adopts the recommendation that notice be provided to well owners within 2,500 feet and extends it to all land owners within 2,500 feet.
4-C Pre-drilling ground water testing should be required to be conducted by the operator and the results provided to MDE and to the well owner. Post-drilling testing is often at the discretion of the well owner, but a best management practice that would enable improved understanding of the potential for effects on ground water would be to require postdrilling and completion testing by the operator for all wells within a pre-determined potentially affected region for a specified time period after completion of well construction activities.	Section VII, Monitoring, Recordkeeping and Reporting accepts this recommendation.
4-D Maryland might wish to consider ways of strengthening its anti-degradation policy to take account of the impacts of non-point source pollution that are a major threat to its high quality waters. One way that this might be accomplished would be by revising the WQS rules to require that any land development practices (<i>e.g.</i> , forest management, MSGD, etc.) conducted in Tier II watersheds meet an anti-degradation standard.	Section IV B, Location Restrictions and Setbacks, defers consideration of special anti-degradation regulations for well drilling until it undertakes revisions to those regulations.
4-E Maryland needs to carefully review its stormwater regulations as they pertain to oil and gas extraction; we recommend oil and gas extraction sites be considered “hotspots.” Based on our review of stormwater management practices in other states, we recommend the use of both “active” and “passive” stormwater management: (1) the construction of properly bermed “zero-discharge” pads that effectively collect all water on a pad site and enable the reuse of this water during drilling and completion operations; and (2) construction of a below-grade lined pond adjacent to the bermed zero-discharge pad that could be used as a sump during active stormwater management phases and easily converted into a retention pond prior to a passive phase.	This recommendation is accepted with modifications in Section VI A, Engineering, Design and Environmental Controls and Standards. Zero-discharge from pads during drilling and completion are adopted in Section VI A. 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.
4-F Post-construction inspections of stormwater structures should occur prior to well drilling and	Section VI A, Engineering, Design and Environmental Controls and Standards.

completion.	Such inspections are routinely carried out by the counties.
<p>4-G There are very long gage records available from USGS for most of the major western Maryland rivers (Youghiogheny, Casselman, Savage, Potomac, Georges Creek) that could possibly be used to support MSGD; data for these and other gaged systems can be used to inform a quantitative analysis of acceptable water withdrawals for MSGD. This analysis is much more difficult for smaller streams and rivers due to data limitations, although we believe that such an analysis should be done. Our experience in Maryland watersheds as well as review of other areas that have completed such analysis, suggest that in western Maryland, water withdrawals for proposed MSGD would need to occur solely from the region's large rivers (and perhaps from one or more reservoirs). Small streams (1) have significant existing withdrawals for drinking water; (2) have small catchment areas and discharges under most conditions; (3) are very unlikely to have excess flow capacity for new permitted withdrawals; and (4) can be readily dewatered. Water may need to be temporarily stored in centralized freshwater impoundments specifically constructed for this purpose, but such impoundments should never be allowed to receive or store any wastewaters.</p>	<p>The State's existing program for water appropriation, which protects small streams, is described in Section VI C, Engineering, Design and Environmental Controls and Standards. The recommendation regarding storage of water and wastewater are accepted in Section VI A and C, Engineering, Design and Environmental Controls and Standards.</p>
<p>4-H To support preparations and training by first responders and well pad staff for any chemical emergencies, lists of chemicals to be used on site (plus appropriate toxicological data, chemical characterizations, MSDS, and spill clean-up procedures) should be included in permit applications.</p>	<p>These recommendations are accepted in Section VI D and P, Engineering, Design and Environmental Controls and Standards.</p>
<p>4-I Closed-loop drilling systems that sit within secondary (and perhaps tertiary) containment are preferable to open pit systems and should be considered a best practice for Maryland.</p>	<p>Section VI A, Engineering, Design and Environmental Controls and Standards, adopts this recommendation.</p>
<p>4-J Maryland should include a very strong preference for on-site recycling of wastewaters in permitting of shale gas development. Under no circumstances should Maryland allow discharge of untreated brine, partially-treated brine, or residuals from brine treatment facilities, into the waters of the</p>	<p>These recommendations are accepted in Section VI C and K, Engineering, Design and Environmental Controls and Standards.</p>

state. Development of brine treatment plants that recycle water to drillers should be discouraged in favor of on-site treatment by mobile units and immediate reuse as this decreases truck transport and associated impacts.	
4-K Maryland should review the relevant regulations surrounding development and use of underground injection wells for produced water from shale gas development and, at the same time, evaluate the capacity of nearby states to accept produced water or residual brine from treatment of produced water before permitting any development in the state.	In Section VI K, Engineering, Design and Environmental Controls and Standards, the Departments recommend deferring consideration of underground injection wells because it is not likely that any will be located in Maryland. As part of the permit application, applicants will be required to plan for the storage, treatment and disposal of wastewater.

Chapter 5 – Protecting terrestrial habitat and wildlife

UMCES-AL	MDE and DNR
5-A Minimize well pad size, cluster multiple well pads, and drill multiple wells from each pad to minimize the overall extent of disturbance and reduce fragmentation and associated edge effects.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
5-A.1 Concentrate operations including roads on disturbed and open lands, ideally in locations zoned for industrial activity and/or close proximity to major roads.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
5-A.2 Adopt a no-net-loss of forest policy requiring any activities that remove forest to be offset by plantings elsewhere in the region.	Section IV B, Location Restrictions and Setbacks. The Departments generally accept the proposed siting best practices recommendation and note that rules regarding acreage determination and temporary vs. permanent losses will need to be developed.
5-A.3 Implement comprehensive planning process to address the cumulative impact of multiple projects, to channel development into areas with greater amounts of existing disturbance, and to avoid areas with intact forests (especially forest interior habitat).	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
5-B Allow for freshwater impoundments only. Impoundments should not be used for flowback or produced wastewater.	This recommendation is accepted in Section VI A, Engineering, Design and Environmental Controls and Standards.
5-B.1 Require watertight, closed metal tanks with secondary containment for all storage of	This recommendation is accepted in Section VI A and P, Engineering, Design

chemicals and wastewater.	and Environmental Controls and Standards.
5-B.2 Include runoff and spill prevention, response, and remediation plans as part of the permitting process	This recommendation is accepted in Section VI P, Engineering, Design and Environmental Controls and Standards.
5-C Establish and enforce setbacks to conserve terrestrial and aquatic biodiversity.	Section IV A, Location Restrictions and Setbacks. The Departments accept the proposed location restrictions and setbacks recommendation.
5-C.1 Enforce 300 ft minimum setbacks from all floodplains, wetlands, seeps, vernal pools, streams, or other surface water bodies.	Section IV A, Location Restrictions and Setbacks. The Departments have expanded this setback to 450 ft.
5-C.2 Exclude all development activities from priority conservation areas (BioNet Tier I and Tier II sites and wildlands). Enforce a 600 ft setback from these areas.	Section IV A, Location Restrictions and Setbacks. The Departments accept the proposed location restrictions and setbacks recommendation.
5-C.3 Enforce 1,000 ft setback from any cave to reduce stress to bats and other obligate subterranean species.	Section IV A, Location Restrictions and Setbacks. The Departments accept the proposed location restrictions and setbacks recommendation.
5-D Review local noise ordinances to ensure they are sufficiently protective. Artificial sound barriers and mufflers should be considered where natural noise attenuation would be inadequate, especially in proximity to priority conservation areas.	Section VI N, Engineering, Design and Environmental Controls and Standards. The Departments accept the proposed siting best practices recommendation.
5-D.1 Avoid construction and drilling operations during sensitive migratory and mating seasons.	Section VI E, Engineering, Design and Environmental Controls and Standards. The Departments generally accept the recommendation, noting that once drilling and fracturing operations have been initiated it is not safe to halt operations except under an emergency.
5-E Reduce the amount of light pollution at drill pad sites by restricting night lighting to only when necessary and to only the amount of lighting required, direct light downward, instead of horizontally, use fixtures that control light directionality well, minimize glare, and use low pressure sodium (LPS) light sources whenever possible.	Section VI M. Engineering, Design and Environmental Controls and Standards, accepts this recommendation.
5-E.1 When drill pads are located within	Section VI M, Engineering, Design and

1,000ft of aquatic habitat, vegetative screens and additional lighting restrictions could be required to reduce light pollution into these sensitive areas.	Environmental Controls and Standards, accepts this recommendation.
5-F Co-locate linear infrastructure as practicable with current roads, pipelines and power lines to avoid new disturbance.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
5-F.1 Avoid stream crossings and any disturbances to wetlands and riparian habitat.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
5-G Submit an invasive species plan as part of permit application for preventing the introduction of invasive species and controlling any invasive that is introduced.	Section VI O, Engineering, Design and Environmental Controls and Standards accept this recommendation.
5-G.1 The invasive species management plan should emphasize early detection and rapid response and include baseline flora and fauna inventory surveys of site prior to operations and long-term monitoring plans for areas that could become problematic after gas development occurs.	Section VI O, Engineering, Design and Environmental Controls and Standards, and Section VII, Monitoring, Recordkeeping and Recording accept this recommendation.
5-H Develop a two-phased reclamation strategy comprised of (1) interim reclamation following construction and drilling to reduce opportunities for invasion and (2) postactivity restoration using species native to the geographic range and seed that is certified free of noxious weeds.	Section VI O and R, Engineering, Design and Environmental Controls and Standards, accepts this recommendation.

Chapter 6 – Protecting aquatic habitat, wildlife, and biodiversity

UMCES-AL	MDE and DNR
6-A Direct disturbance of any aquatic habitat for shale gas development should not be permitted.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
6-B A minimum 300 ft aquatic habitat setback should be applied, with the distance measured from the edge of any land disturbance, not from the location of a particular wellbore, to the edge of a particular habitat.	Section IV A, Location Restrictions and Setbacks expands this recommended setback to 450 ft.
6-C Data that describe the biological resources of western Maryland should be developed and made available to MSGD applicants. These data should be used to effectively channel development away from high-value biological resources and into industrial zones accessible via existing roads and highways.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.

<p>6-D The use of multi-well pads to access relatively large (~2 mi²) resources of shale gas would enable the maintenance of reasonably low levels of surface development.</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.</p>
<p>6-E Cumulative surface development (including all well pads, access roads, public roads, etc.) could be maintained at less than 2 percent of the watershed area in high-value watersheds.</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation as a planning principle for minimizing cumulative surface impacts.</p>
<p>6-F Initially, all MSGD could be excluded from areas of high-value assets (<i>e.g.</i>, BioNet sites, stronghold watersheds, Tier II watersheds, etc.)</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation as a planning principle for the applicant to consider when determining the sequence of well pad development.</p>
<p>6-G Closed drilling systems on zero-discharge drilling pads on which all drilling and hydraulic fracturing fluids, chemicals, and liquid wastes are collected and stored in steel tanks that provide superior primary containment to holding ponds are a best management practice. Vacuum trucks could be used to handle on-site runoff during drilling and well completion (see Chapter 4).</p>	<p>Sections VI A and E, Engineering Design and Environmental Controls, accept this recommendation.</p>
<p>6-H Maryland should require an invasive species management plan of industry prior to any drilling operations. Such a plan should include, at the minimum:</p>	<p>Section VI O, Engineering Design and Environmental Controls, accepts this recommendation.</p>
<p>6-H.1 A description of water sources to be used to fill any impoundment, including analysis of any invasive species that might be present at the withdrawal site but absent from the watershed where the impoundment will be located.</p>	<p>Section VI C and O, Engineering Design and Environmental Controls accepts this recommendation</p>
<p>6-H.2 Water withdrawal equipment should be power-washed and rinsed with clean water before leaving the withdrawal site.</p>	<p>Section VI C and O, Engineering Design and Environmental Controls, accepts this recommendation.</p>
<p>6-I Maryland should prohibit the discharging of any previously impounded water back into a natural water body, thus reducing the chance for the introduction of invasive species and short-term elevated thermal regimes in streams.</p>	<p>Section VI O, Engineering Design and Environmental Controls, accepts this recommendation.</p>
<p>6-J Wherever possible, existing roads should be used in MSGD. Where new roads are required, PA</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) and Section VI A, Engineering Design and</p>

DCNR recommendations could be adopted:	Environmental Controls, accept this recommendation.
6-J.1 Use materials and designs (<i>e.g.</i> , crowning, elimination of ditches, etc.) that encourage sheet flow as the preferred drainage method for any new construction or upgrade of existing gravel roadways.	This recommendation is addressed in Section VI A, Engineering Design and Environmental Controls.
6-J.2 Where stream crossings are unavoidable, use bridges or arched culverts to minimize disturbance of streambeds.	Section IV B, Location Restrictions and Setbacks. The Departments accept the proposed siting best practices recommendation.
6-J.3 Promote the use of geotextiles as a way of reducing rutting and maintaining subbase stability.	This recommendation is addressed in Section VI A, Engineering Design and Environmental Controls.
6-J.4 Open trenches within streams should be avoided in favor of using directional boring techniques.	Section IV B, Location Restrictions and Setbacks. The Departments accept the proposed siting best practices recommendation and propose developing siting policies to guide pipeline planning and use of hydraulic directional drilling practices.
6-K In general, during road and pad construction a combination of BMPs should be used to reduce sediment and erosion, recognizing that additional protective measures might be necessary during wet times of the year (primarily late winter and early spring).	This recommendation is accepted in Section VI A, Engineering Design and Environmental Controls.

Chapter 7 – Protecting public safety

UMCES-AL	MDE and DNR
7-A The first line of defense in protecting public safety is designing MSGD operations in a way that maintains separation between MSGD infrastructure (including transportation routes) and the public.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation and is also included in Section VI B, Engineering Design and Environmental Controls.
7-A.1 Facilities should be sited as far away as possible from homes, businesses, public buildings, or places with high levels of recreational activity (<i>e.g.</i> , hiking trails, parks, picnic areas, etc.) (see Chapter 9 also).	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
7-A.2 Best management practices in well construction (<i>e.g.</i> , casing and cementing) should be	This recommendation is accepted in Section VI F, Engineering Design and

followed to ensure wellbore integrity and isolation (see Chapter 3).	Environmental Controls.
7-A.3 Proper monitoring and pre-development assessment are important steps to limit the migration of hydrocarbons, brines, or hydraulic fracturing fluids into ground water, causing pollution of underground drinking water supplies and to enable rapid detection in the event of migration (see Chapters 1 and 4).	Section VII, Monitoring, Recordkeeping and Reporting accepts this recommendation.
7-B MSGD applicants should be required to develop site-specific, emergency response plans (ERP) that describes in detail how a particular operator will respond to different emergencies that may occur during each phase of shale gas development at sites, or transportation routes between sites, permitted for MSGD.	This recommendation is accepted in Section VI P, Engineering Design and Environmental Controls.
7-B.1 The ERP must include many types of standard information, including the names and contact information for first responders, and location (including GPS coordinates) of MSGD sites.	This recommendation is accepted in Section VI P, Engineering Design and Environmental Controls.
7-B.2 The ERP must include variations on standard responses demonstrating sensitivity to weather, time of day, time of year, and the particular geography of sites (<i>e.g.</i> , topographic and soil conditions).	This recommendation is accepted in Section VI P, Engineering Design and Environmental Controls.
7-B.3 The ERP must also include a list of all chemicals or additives used, expected wastes generated by hydraulic fracturing, approximate quantities of each material, the method of storage on-site, MSDS for each substance, toxicological data, and waste chemical properties.	This recommendation is accepted in Section VI P, Engineering Design and Environmental Controls.
7-C Best management practices implemented to avoid emergencies should include:	This recommendation is accepted in Section VI Q, Engineering Design and Environmental Controls.
7-C.1 Adequate perimeter fencing (at least a 6 ft high chained link or equivalent), gates (with keyed locks), and signage in place around drill rigs, engines, compressors, tanks, impoundments, and separators, to restrict public access.	This recommendation is accepted in Section VI Q, Engineering Design and Environmental Controls.

7-C.2 Use of safety or security guards to further control access (particularly important during active drilling and completion phases of an operation).	This recommendation is accepted in Section VI Q, Engineering Design and Environmental Controls.
7-C.3 Duplicate keys to all locks should be provided to the regulatory agency and to local emergency responders.	This recommendation is accepted in Section VI Q, Engineering Design and Environmental Controls.
7-D Maryland’s Department of Transportation should calculate, evaluate, and address the major impacts of additional truck traffic on the road and highway system prior to the state permitting MSGD.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation and is also included in Section VI B, Engineering Design and Environmental Controls.
7-D.1 Counties and municipalities should also undertake an inventory and structural evaluation of locally-owned bridges currently exempt from federally mandated inspections to ensure that these structures are capable of safely handling the additional traffic (and loads) associated with MSGD.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation and is also included in Section VI B, Engineering Design and Environmental Controls.
7-D.2 The state should establish a protocol to allow for emergency transport of heavy or oversized equipment during off-hour periods (evenings, nights, and weekends).	Section VI B, Engineering Design and Environmental Controls, indicates that the State and Garrett County have existing protocols, but it is unknown whether one exists for Allegany County.

Chapter 8 – Protecting cultural, historical, and recreational resources

UMCES-AL	MDE and DNR
8-A Applicants for drilling permits should be required to consult with Maryland Historical Trust during the planning and permit application process to identify all eligible or existing cultural or historical sites in the vicinity of proposed MSGD activity (including all drill pad sites, gas pipelines, roads, and transportation routes to and from MSGD facilities).	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
8-B Regardless of whether or not a proposed operation would be located on state or federal land, best practice would require close consultation with local governments, state park and forest officials, national park managers, and wildlife managers who are familiar with the resources that could be impaired by shale gas development.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
8-C Applicants should be required to submit a	Section IV B, Location Restrictions and

<p>visual resource mitigation plan as part of the permit application process based on site-specific assessment (<i>i.e.</i>, viewshed analysis).</p>	<p>Setbacks. The Departments accept the proposed siting best practices recommendation, but note that a temporary impact and a permanent impact will be evaluated differently.</p>
<p>8-D Site selection for drilling pads in Maryland should be locations that can provide natural vegetative or topographic screening.</p>	<p>Section IV B, Location Restrictions and Setbacks. The Departments accept the proposed siting best practices recommendation.</p>
<p>8-E Siting of well pads, or the routing of MSGD-related truck traffic, near high use recreation areas should be avoided if possible.</p>	<p>Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation and is also included in Section VI B, Engineering, Design and Environmental Controls and Standards.</p>
<p>8-F Maryland should impose a minimum 300 ft setback from all cultural and historical sites, state and federal parks, trails, wildlife management areas, natural areas, wildlands, scenic and wild rivers, and scenic byways to protect the region’s most important cultural, historical, recreational, and ecological resources. Setback considerations should include high use areas, noise and visual impacts, and public safety concerns.</p>	<p>Section IV A, Location Restrictions and Setbacks. The Departments generally accept the proposed location restrictions and setbacks recommendation with the following modifications. A 300 ft setback may not adequate to protect the outdoor recreational visitor’s experience. DNR will develop new maps of public outdoor recreational use areas to guide additional recreational setbacks and mitigation measures for minimizing public use conflicts.</p>
<p>8-G The calculation of setback distances should consider prevailing winds, topography, and viewsheds, and repeatable formulas for calculating setbacks should be established.</p>	<p>Section IV A, Location Restrictions and Setbacks. The Departments generally accept the proposed location restrictions and setbacks recommendation. These factors are also considered in Section VI M, Engineering, Design and Environmental Controls for lighting management.</p>
<p>8-H Mitigative techniques, such as the use of visual screens, sound barriers, camouflage, and landscaping near cultural and historical sites, as well as restricting the times of gas development operations, should be required to minimize disturbances and conflicts with recreational activities in areas adjacent to gas development zones.</p>	<p>Section IV B, Location Restrictions and Setbacks. The Departments accept the proposed siting best practices recommendation. These factors are also considered in Section VI M, Engineering, Design and Environmental Controls for lighting</p>
<p>8-I Any permitted shale gas development activities in the vicinity of public recreational</p>	<p>Section VI E, Engineering, Design and Environmental Controls. The Departments</p>

sites—including state forests—should be timed so as to avoid periods of peak recreational activity (e.g., holiday weekends, first day of trout season, spring and fall hunting seasons, whitewater release dates, etc.). Maryland DNR should collect and provide data to help inform peak activity times.	generally accept the recommendation, noting that once drilling and fracturing operations have been initiated it is not safe to halt operations except under an emergency.
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Chapter 9 – Protecting quality of life and aesthetic values

UMCES-AL	MDE and DNR
9-A Well-pad siting should consider the multiple factors that influence the quality of life and aesthetics of rural life in western Maryland (e.g., location of existing infrastructure, traffic loads on existing roads, etc.)	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
9-A.1 Site well pads away from occupied buildings (e.g., dwellings, churches, businesses, schools, hospitals, and recreational facilities)	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
9-A.2 Site well pads and associated facilities in industrial parks (either new or existing) designed and zoned for this type of industrial activity	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
9-A.3 Site well pads in close proximity to major interstate highways and exit ramps designed to efficiently handle round-the-clock transportation	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation.
9-A.4 Reduce truck traffic associated with water hauling through use of temporary pipelines where possible.	Section VI B, Engineering, Design and Environmental Controls, accepts this recommendation.
9-B Each of the counties in western Maryland should revisit noise regulations and enforcement policies and confirm they are appropriate for this industrial activity.	Section VI N, Engineering, Design and Environmental Controls addresses noise regulations. No State action is necessary to address this recommendation.
9-C No drilling or compressor stations should be permitted within 1,000 ft of an occupied building.	Section IV A, Location Restrictions and Setbacks accepts this recommendation.
9-D Require electric motors (in place of diesel-powered equipment) for any operations within 3,000 ft. of any occupied building	Noise is addressed in Section VI N, Engineering, Design and Environmental Controls and Standards.
9-D.1 Encourage electric motors in place of diesel-powered equipment wherever possible.	This recommendation is accepted in Section VI E, Engineering, Design and Environmental Controls and Standards.
9-D.2 Restrict hours and times of operation to avoid or minimize the greatest conflicts between	VI E, Engineering, Design and Environmental Controls and Standards.

the public and MSGD.	The Departments generally accept the recommendation, noting that once drilling and fracturing operations have been initiated it is not safe to halt operations except under an emergency.
9-D.3 Require ambient noise level determination prior to operations.	Noise is addressed in Section VI N, Engineering, Design and Environmental Controls and Standards. The Departments do not see a need for ambient noise measurements because the noise standards apply to noise during operations.
9-D.4 Require construction of artificial sound barriers where natural noise attenuation would be inadequate.	This recommendation is accepted in Section VI N, Engineering, Design and Environmental Controls and Standards.
9-D.5 Equip all motors and engines with appropriate mufflers.	Section VI N, Engineering, Design and Environmental Controls and Standards, requires that noise be controlled, by mufflers if necessary.
9-E All permit applicants should develop and submit a detailed transportation plan for approval by the regulatory authority prior to conducting any site development, drilling, well work over, or well completion activities	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation and is included in Section VI B, Engineering, Design and Environmental Controls and Standards.
9-E.1 The approval process for the transportation plan should allow for adequate comment by the public, state transportation agencies, and county roads departments.	Section III, Comprehensive Gas Development Plans (CGDP) adopts this recommendation and is included in section VI B, Engineering, Design and Environmental Controls and Standards.
9-F It is recommended that new road construction follows PADCNR guidelines for construction of permanent non-paved roads to address potential environmental impacts, offset erosion, and avoid damage to environmentally sensitive areas.	This recommendation is addressed in Section VI, A, Engineering, Design and Environmental Controls and Standards.
9-G We recommend the use of viewshed analysis to help determine the best location for MSGD-related infrastructure as well as to determine what mitigative techniques would be appropriate.	This recommendation is accepted in Section III, Comprehensive Gas Development Plans (CGDP) and Section IV B, Location Restrictions and Setbacks.
9-H We recommend use of mitigative techniques (e.g., the use of visual screens, camouflages, paint schemes, evergreen buffers, and landscaping techniques) to minimize degradation of western	This recommendation is accepted in Section IV B, Location Restrictions and Setbacks.

Maryland viewsheds by MSGD.	
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Chapter 10 – Protecting agriculture and grazing

UMES-AL	MDE and DNR
10-A Soil conditions at sites being considered for shale gas development should be evaluated as part of the planning process.	This recommendation is accepted in Section IV B, Location Restrictions and Setbacks.
10-B Prime agricultural soils and prime farmland protected by Maryland’s existing land easement programs should not be disturbed for well pad siting, road construction, or any ancillary gas development activities.	This recommendation is accepted in Section III, Comprehensive Gas Development Plans (CGDP).
10-C Highly erodible soils should also be identified as part of the planning process and appropriate best practices employed to prevent erosion and sedimentation problems in developing these areas (see Chapter 4).	This recommendation is accepted in Section IV B, Location Restrictions and Setbacks.
10-D Well pads, infrastructure, roads, and utility corridors should generally be sited along field edges, thus avoiding bisection of fields.	This recommendation is accepted in Section IV B, Location Restrictions and Setbacks.
10-E Topsoil should be stockpiled during site development activities, covered during storage, redistributed back onto agricultural land as part of the land reclamation process, and soil compaction should be avoided at all times.	This recommendation is accepted in Section VI R, Engineering, Design and Environmental Controls and Standards.
10-F Operators must fence livestock out of gas development areas.	This recommendation is accepted in Section VI Q, Engineering, Design and Environmental Controls and Standards.

APPENDIX G – JUSTIFICATION FOR EXPANSION OF THE AQUATIC HABITAT SETBACK FROM 300 FT TO 450 FT

Maryland’s Proposed Setback (Minimum Riparian Buffer) Recommendations for Gas Development Infrastructure Associated with Aquatic Habitats in Western Maryland

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Maryland Department of Natural Resources

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Riparian buffers are among the most diverse and functionally-important landscape features because of their unique position as an interface (ecotone) between aquatic and terrestrial habitats. Intact riparian buffers are vital components of watersheds and provide important ecological services. Buffers serve to protect surface and ground water quality from impacts associated with human land uses. Buffers provide food and habitat for an array of plants and animals (i.e., they support high biodiversity) and, if wide enough, provide corridors essential for terrestrial wildlife movements and breeding areas for forest interior-dwelling birds. Although riparian buffers comprise a small percentage of a watershed area, they often harbor a disproportionately high number of plants and animals. Riparian buffers along headwater (1st, 2nd, and 3rd order) streams have much more influence on overall water quality than buffers occurring downstream along larger streams and rivers.

The final UMCES-AL Report titled “Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland” authored by Keith Eshleman and Andrew Elmore recommends a minimum setback (buffer width) of 300 ft for well pad locations from all aquatic habitats, including streams, rivers, seeps, springs, vernal pools, wetlands, lakes, ponds, reservoirs, floodplains and other surface water bodies (Table 1-1: page 1-12). This minimum setback is measured from the limit of disturbance (not the wellbore) to the edge (high water mark or landward edge of an active floodplain) of the specific aquatic habitat present.

The UMCES-AL recommendation of a minimum setback of 300 ft in their report was based, in large part, on actual practices being employed by neighboring states where Marcellus shale gas development is underway. The UMCES-AL Report authors wanted to be reasonably consistent with the best setback practices in other states. Although the Maryland Department of the Environment (MDE) and the Maryland Department of Natural Resources (DNR) recognize that the proposed aquatic setback recommendation outlined in the UMCES-AL Report (Table 1-1, page 1-12) would provide some level of protection for water quality and biological diversity, we feel that this setback recommendation should be increased to better reflect the level of protection the Departments must ensure for our environment and natural resources. Furthermore, the

Departments determined that it is necessary to make the following modifications and additions: 1) Prohibit the development of well pads on land with a slope > 15 percent (this was recommended in the UMCES-AL final report, but not listed as a key recommendation), 2) Expand the drill pad location restrictions and setbacks for aquatic habitats listed in Table 1-1 to include all natural gas development that results in surface alterations (including permanent roads, compressor stations, and other needed infrastructure), and 3) Recommend riparian buffer expansion (*i.e.*, setbacks) to 450 ft to increase water quality and biodiversity protection.

As explained in more detail below, a 450 ft setback will provide significant water quality protection, as would the 300 ft setback recommended in the UMCES-AL Report. But, in addition, a minimum setback of 450 ft will provide a higher level of protection for biodiversity (with a focus on aquatic biodiversity), ensure sufficient corridor width needed for terrestrial wildlife movement and forest interior-dwelling bird species, and reduce the visual, noise, and light impacts of gas extraction operations in close proximity to aquatic habitats.

The Departments' recommended minimum setback distance from aquatic habitats of 450 ft is supported by several studies on buffer or life zone requirements for reptiles and amphibians. Semlitsch and Bodie (2003) summarized data from the scientific literature on the use of terrestrial habitats by amphibians and reptiles associated with pond and stream habitats, both permanent and temporary, in the United States and Canada. From these data, they calculated mean minimum and mean maximum core terrestrial habitat distances measured from the outer edge of aquatic areas; *i.e.*, essentially riparian buffer widths. Mean minimum distances were 127 m (417 ft) for 33 reptile species and 159 m (522 ft) for 32 amphibian species. The mean minimum distance from aquatic areas for all herpetofauna (65 amphibian and reptile species) was 142 m (466 ft). By comparison, mean maximum distances (buffer widths) were 289 m (948 ft) for reptiles and 290 m (951 ft) for amphibians. Mean maximum distances for all herpetofauna was 289 m (948 ft). The Semlitsch and Bodie (2003) paper can be found here: <http://www.mctga.org/Stream%20Buffer%20Information/Semlitsch%20and%20Bodie%202003.pdf>. In another paper, Calhoun and deMaynadier (2007) reported even longer mean and maximum life zone distances (buffer widths) from aquatic areas: for marbled salamanders (368 and 1476 ft, respectively), spotted salamanders (390 and 817 ft), Jefferson salamanders (476 and 2051 ft), and wood frogs (633 and 1549 ft). Harper et al. 2008 indicated that a minimum terrestrial core habitat radius of 100 to 165 m (328 to 541 ft) is necessary to maintain populations of spotted salamanders (95 percent probability and persistence of 20 years). The four amphibian species referenced above are present in western Maryland (including Garrett and Allegany Counties). The Jefferson salamander has a State rank of S3 (*i.e.*, Watchlist), meaning that is considered rare to uncommon in Maryland.

On June 6, 2011, Governor Martin O'Malley signed [Executive Order](#) 01.01.2011.11⁴⁶ establishing the Marcellus Shale Safe Drilling Initiative. This Executive Order called for additional studies to ensure that Maryland had sufficient information upon which to base

⁴⁶ www.governor.maryland.gov/executiveorders/01.01.2011.11.pdf

a decision to allow or not allow unconventional gas development in western Maryland. In his Executive Order, protection of the State's abundant natural resources was critical. In the spirit of this directive, the Departments recommend a minimum setback for gas development infrastructure associated with aquatic habitats in western Maryland of 450 ft. This buffer width is similar to the mean minimum width of 466 ft for 65 herpetofauna species recommended by Semlitsch and Bodie (2003). Although a minimum setback even greater than 450 ft is supported by scientific studies, the Departments feel that this setback, if strictly enforced, should be sufficiently protective of water quality and biodiversity, and still provide for ample amounts of land surface for infrastructure necessary for Marcellus Shale natural gas development (if/when it is permitted in Maryland).

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APPENDIX H – ACRONYMS

AAPG	American Association of Petroleum Geologists
AMD	Acid mine drainage
AOR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BACI	Before, after, control, impact
BAT	Best Available Technology
BMP	Best Management Practice
BP	Best Practices
CAS	Chemical Abstract Service
CBL	Cement bond logging
CFR	Code of Federal Regulations
CGDP	Comprehensive Gas Development Plan
CO _{2e}	Carbon Dioxide Equivalents
COMAR	Code of Maryland Regulations
CPCN	Certificate of Public Convenience and Necessity
CSSD	Coalition for Sustainable Shale Development
dBA	A-weighted decibels
DNA	Deoxyribonucleic Acid
DNR	Maryland Department of Natural Resources
DOE	Department of Energy (US)
EA	Environmental Assessment
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency (US)
FAQ	Frequently Asked Questions
Fed. Reg.	Federal Register
FERC	Federal Energy Regulatory Commission
ft	Feet
g/bhp-hr	grams per brake horsepower per hour
GAO	Government Accountability Office (US)
GHG	Greenhouse Gas
GIS	Geographic Information System
gpd	Gallons per day
GPS	Global Positioning System
HB	House Bill
HCS	Hazard Communication Standard
HVHF	High volume hydraulic fracturing
IBA	Important Bird Area
IPCC	Intergovernmental Panel on Climate Change
LDAR	Leak Detection And Repair
LFN	Low frequency noise
LOD	Limit of Disturbance
m	Meter

MALPF	Maryland Agricultural Land Preservation Foundation
MDA	Maryland Department of Agriculture
MDE	Maryland Department of the Environment
MET	Maryland Environmental Trust
MGS	Maryland Geological Survey
MMcfd	Million cubic feet per day
MSAC	Marcellus Shale Advisory Commission
MSGD	Marcellus Shale Gas Development
NEA	Natural Environment Area
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NORM	Naturally occurring radioactive material
NPDES	National Pollutant Discharge Elimination System
NRMA	Natural Resources Management Area
NSPS	New Source Performance Standard
OPS	Office of Pipeline Safety
OSHA	Occupational Safety and Health Administration (US)
PAH	Polycyclic aromatic hydrocarbon
PHMSA	Pipeline and Hazardous Materials Safety Administration (US)
PNAS	Proceedings of the National Academy of Sciences
POTW	Publicly owned treatment works
ppm	Parts per million
PSC	Public Service Commission (MD)
PWS	Public Water System
QA/QC	Quality Assurance/Quality Control
RCRA	Resource Conservation and Recovery Act
SB	Senate Bill
SDS	Safety Data Sheets
SDWA	Safe Drinking Water Act
SOPA	Surface Owners Protection Act
SPCC	Spill Prevention Control and Countermeasure
SRBC	Susquehanna River Basin Commission
SRCBL	Segmented radial cement bond logging
STAC	Scientific and Technical Advisory Commission (Chesapeake Bay Program)
SWPA	Source Water Protection Area
TCLP	Toxicity Characteristic – Leaching Procedure
TDS	Total dissolved solids
TEG	Tri-ethylene glycol
TENORM	Technologically enhanced naturally occurring radioactive material
TMDL	Total Maximum Daily Load
TSS	Total suspended solids
UIC	Underground Injection Control
UK	United Kingdom

UMCES-	University of Maryland Center for Environmental Science – Appalachian
AL	Laboratory
USC	United State Code
USDA	United States Department of Agriculture
USGS	United States Geological Survey
VAD	Vibroacoustic disease
VOC	Volatile organic compound
WIP	Watershed Implementation Plan
WWTP	Wastewater treatment Plant