Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland

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Final Report submitted to:
Maryland Department of the Environment
Baltimore, MD

February 18, 2013

Acknowledgments

We solicited and received the help of quite a few people during the completion of this project. While the project investigators (KNE and AJE) are responsible for the content of the final report, we especially acknowledge three individuals who helped us with the organization, content, and writing of several chapters: Russell R. Dickerson (Department of Atmospheric and Oceanic Science, University of Maryland; Chapter 2) Jeanne M. VanBriesen (Department of Civil and Environmental Engineering, Carnegie Mellon University; Chapter 4); and Todd R. Lookingbill (Department Geography and the Environment, University of Richmond; Chapter 5). Previous time commitments precluded them from assisting with other sections of the report, so they are listed as chapter co-authors. We thank the following individuals for providing us with data: Scott Bearer, Deborah Carpenter, Jennifer Chadwick-Moore, Kevin Coyne, Lynn Davidson, Gregory Day, Dan Feller, Dave Foreman, Mike Garner, John Grace, Jeff Halka, Kara Hawkins, Jaron Hawkins, Greg Hildreth, Zoe Johnson, Catherine McCall, Phung Pham, Gene Piotrowski, Matt Rowe, Matt Sell, Frank Siano, Matthew Stover, and Kevin Wagner. Robert Sabo compiled much of the extant literature on best practices that underpinned our analyses of best practices. Steven Guinn produced all of the maps used in this report and performed many of the geographic analyses on which our recommendations are based. Robert Hilderbrand contributed text and comments to Chapter 6. Finally, Christine Conn (Maryland DNR), Brigid Kenney (MDE), Ron Klauda (Maryland DNR) and several other anonymous reviewers provided constructive criticism of an earlier draft of the report.

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List of Acronyms and Abbreviations

AMD	acid mine drainage
API	American Petroleum Institute
BCF	billion cubic feet
bhp-hr	brake horsepower-hour
BioNET	Biodiversity Conservation Network
BMP	best management practice
BOPE	blow-out prevention equipment
BTEX	benzene, toluene, ethylbenzene, and xylene
CBL	cement bond logging
CBM	coal bed methane
CDP	comprehensive drilling plan
CNHI	County Natural Heritage Inventory
CO	carbon monoxide
CO_2	carbon dioxide
COD	chemical oxygen demand
COGCC	Colorado Oil and Gas Conservation Commission
COMAR	Code of Maryland Regulations
CWA	Clean Water Act
DMRM	Division of Mineral Resources Management (OH)
DNR	Department of Natural Resources (MD)
EAF	environmental assessment form

ELAP	Environmental Laboratory Accreditation Program
ERP	emergency response plan
ERT	Environmental Review Tool
ESC	erosion and sediment control
FCA	Forest Conservation Act (MD)
FEMA	Federal Emergency Management Agency
ft	feet
GHG	greenhouse gas
HAB	harmful algal blooms
HAP	hazardous air pollutant
HC	hydrocarbon
HDPE	high density polyethylene
HDT	Hoffman Drainage Tunnel
HF	hydraulic fracturing
HP	horsepower
HVHF	high volume hydraulic fracturing
HQW	high quality waters
HUC	hydrologic unit code
ICPRB	Interstate Commission on the Potomac River Basin
IR	infrared radiation
kg	kilogram
km	kilometers
km^2	square kilometers

LLRW	low-level radioactive waste
LPG	liquefied petroleum gas
L/s	liters per second
LWD	logging while drilling
MALPF	Maryland Agricultural Land Preservation Foundation
MBSS	Maryland Biological Stream Survey
MDA	Maryland Department of Agriculture
MDE	Maryland Department of the Environment
MG	million gallons
MGD	million gallons per day
mg/L	milligrams per liter
MGS	Maryland Geological Survey
MHT	Maryland Historical Trust
MMCF	million cubic feet
MSDS	material safety data sheet
MSGD	Marcellus shale gas development
MSSCS	Maryland Synoptic Stream Chemistry Survey
MWD	measurement while drilling
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NORM	naturally occurring radioactive materials
NO_x	nitrous oxide
NPDES	National Pollutant Discharge Elimination System

NRC	National Research Council
NSPS	New Source Performance Standards
NWI	National Wetlands Inventory
NYSDEC	New York State Department of Environmental Conservation
O_3	ozone (photochemical smog)
ONRW	outstanding national resource waters
OVM	organic vapor meter
ORSANCO	Ohio River Valley Water Sanitation Commission
PA DCNR	Pennsylvania Department of Conservation and Natural Resources
PA DEP	Pennsylvania Department of Environmental Protection
pCi/g	picocuries per gram
PE	professional engineer
$PM_{2.5}$	fine particulate matter (< 2.5 μm)
PNDI	Pennsylvania natural diversity inventory
PNHP	Pennsylvania Natural Heritage Program
POTW	publically owned treatment works
PPC	prevention, preparedness, and contingency
psi	pounds per square inch
QA/QC	quality assurance/quality control
RAIN	River Alert Information Network
RCRA	Resource Conservation and Recovery Act
RGGI	Regional Greenhouse Gas Initiative
RP	recommended practice

RW	radioactive waste
SAV	submerged aquatic vegetation
SHA	State Highway Administration (MD)
SRBC	Susquehanna River Basin Commission
SRCBL	segmented radial cement bond logging
STRONGER	State Review of Oil and Natural Gas Environmental Regulations, Inc.
SWPPP	stormwater pollution prevention program
TCEQ	Texas Commission on Environmental Quality
TCF	trillion cubic feet
TDS	total dissolved solids
TENORM	technologically-enhanced, naturally-occurring radioactive materials
TNC	The Nature Conservancy
TSS	total suspended solids
TVD	true vertical depth
UIC	Underground Injection Control
ULSD	ultra low sulfur diesel
USACE	United States Army Corps of Engineers
USDA	United States Department of Agriculture
USDW	underground source of drinking water
USEPA	United States Environmental Protection Agency
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
VDL	variable density log

VOC	volatile organic compound
WOC	wait on cement
WQS	water quality standards
WSSC	Wetlands of Special State Concern
WVDEP	West Virginia Department of Environmental Protection

Summary of key findings and major recommendations[1]

The Marcellus shale formation underlying numerous Appalachian states is considered the largest gas-bearing shale formation in the United States. The thousands of new gas wells that have been drilled in this region since 2004 are testimony to a revolution in domestic natural gas production in the U.S. through so-called "unconventional" development that includes both modern horizontal drilling and high volume hydraulic fracturing technologies. Unlike neighboring Pennsylvania that participated fully in the initial boom in exploration and production between 2005 and 2009 (drilling has occurred extensively both on private and public lands in Pennsylvania), Maryland (with a significantly smaller resource) has chosen to stay on the sidelines with an unofficial moratorium on unconventional Marcellus shale gas development (MSGD) while it studies the lessons from other states, determines whether development can go forward safely, and evaluates it options. The present study of best management practices (BMPs) for Marcellus shale gas development represents an effort to determine what actual practices would provide the maximum protection of Maryland's environment, natural resources, and public safety should the state decide to move forward with development of this resource in the near future.

We carefully reviewed the current regulations governing unconventional shale gas development in five other states (Colorado, New York, Ohio, Pennsylvania, and West Virginia), as well as the recommendations of many other expert panels and organizations that have reviewed both regulations and BMPs in these and other states. We visited several well pads as part of three organized field trips that allowed us to gain an important visual perspective of the operations, practices, and challenges involved in conducting MSGD. Wherever possible, we also reviewed the scientific literature to evaluate the proven effectiveness of different practices, but the lack of comprehensive, data-driven studies of the impacts of MSGD both on-site and off-site present a significant impediment to recommending best practices on the basis of this criterion alone. For this reason, we have explicitly chosen to identify and recommend specific BMPs that—mostly on the basis of our professional judgment—would provide as much protection of Maryland's natural, cultural, historical and recreational resources; the environment; and public safety as can reasonably be provided while allowing MSGD to move forward.

We believe that it is inevitable that there will be negative impacts from MSGD in western Maryland (and perhaps beyond the state's borders) and that a significant portion of these "costs" will be borne by local communities. Heavy truck traffic on local roads, noise and odors emanating from drilling sites, conflicts with outdoor recreation, diminished tourism, reduced biodiversity, and deterioration of air and water quality are some examples of the types of impacts that are likely even under the best of circumstances. While difficult to quantify in economic terms, these "costs" will ideally be greatly outweighed by the benefits of increased economic activity—otherwise it is very difficult to make a case that MSGD should occur at all. Our goal was to identify and recommend specific BMPs that would provide maximum protection of

[1] Chapter co-authors: Keith N. Eshleman, Ph.D. and Andrew J. Elmore, Ph.D. (both at: Appalachian Laboratory, University of Maryland Center for Environmental Science, Frostburg, MD 21532)

Maryland's environment, natural resources, and public safety. There are a variety of types of resources and hazards—in some cases overlapping—distributed across the western Maryland landscape that present important constraints on MSGD. For this reason, implementation of some BMPs will effectively result in the exclusion of MSGD from select areas of the region to reduce the risk of impacts, thus limiting to some degree the total volume of gas eventually extracted. Due to the nature of this activity in which well bores can be drilled horizontally 8,000 ft from the well pad, it will often be possible to drill under the most valuable and at-risk resources of western Maryland. This potential is enhanced through the use of multi-well pads that are capable of draining between one and two square miles of the target formation. Further, locating multi-well pads in dense clusters—with clusters spaced as far apart as is technically feasible—makes maximum use of horizontal drilling technology and could be an important BMP in terms of minimizing surface development impacts. With careful and thoughtful planning (e.g., co-location of associated infrastructure wherever possible), it may be possible to develop much of the gas resource in a way that converts less than 1-2% of the land surface, even when accounting for the need for ancillary infrastructure such as access roads, pipelines, and compressor facilities. While this build-out scenario would occupy much less surface area than other forms of development, even with the most protective BMPs in place it would certainly not be expected to occur without some significant negative impacts on the western Maryland region.

Maryland already has a reasonably well-developed set of regulations that pertains mostly to conventional oil and gas development, but the state lacks a regulatory/enforcement structure to address unconventional gas development. Clearly, a regulatory program would have to quickly "ramp up" to effectively address the myriad issues that would be presented by MSGD in the state and to avoid some of the problems that have occurred elsewhere. An important best management practice is therefore to "go slow" and allow a new regulatory structure and experience in inspection and enforcement to evolve over time and effectively "catch up" to the new technology as MSGD proceeds. If and when MSGD moves forward in western Maryland, we believe that effective planning by local and state governments that moderates the rate at which the gas resource is developed across the region would help mitigate some of the negative effects of "boom-bust" cycles that have occurred elsewhere. There are a number of specific recommendations throughout this report that provide guidance in this area.

In particular, perhaps the single most important among these recommendations is that the state should develop regulations to support the design and implementation of comprehensive drilling plans (CDPs) for MSGD. We envision a voluntary program similar to Colorado's approach (and the program that has been used to develop the Marcellus gas resource in Pennsylvania state forests), but one that provides strong incentives for operators willing to consider this option. After identifying foreseeable oil and gas activities in a defined geographic area upfront, energy companies would work cooperatively with other stakeholders (including state natural resource agencies, counties, citizen groups, etc.) to develop an integrated plan for efficiently exploiting the resource while minimizing impacts on communities, ecosystems, and natural resources. The CDP approach offers many advantages, but the most important one is that it provides a way of effectively channeling this industrial activity into those areas where fewer of the most sensitive resources are "in harm's way" and where new infrastructure needs (e.g., roads, pipelines) are lower. Logically, the first approved CDP would most likely result in permitting an area for drilling where major drilling hazards, risks to public safety, and impacts on sensitive ecological, recreational, historical and cultural resources can be largely avoided. Since we expect that the planning process for a CDP would be longer than for individual well drilling permits, another major advantage of this approach is that it could enable MSGD to move forward at a somewhat slower, more manageable rate. One way the state might incentivize comprehensive gas development planning could be by reducing permit fees and bonding requirements for wells covered under a CDP. Over time, monitoring data collected both on-site and off-site to document impacts (or non-impacts) would be used by the industry to improve BMPs (this is the way the BMP process is supposed to work). Additional CDPs would presumably be dependent upon the industry demonstrating that any impacts from earlier drilling were within acceptable limits or that newer practices were significantly better at reducing any unacceptable impacts observed in prior phases.

A critically important consideration influencing the success of CDPs in Maryland would be careful site selection based on pre-development environmental assessment for well pads and related infrastructure. A careful pre-drilling environmental assessment would include, at a minimum, an assessment of all existing data combined with two years of pre-drilling monitoring, including surface and groundwater testing, inventories of rare, threatened and endangered species, and an assessment of the potential to introduce invasive species during site development or water procurement. Should any changes in observed water quality occur during drilling or production, pre-drilling assessment should make possible a defendable determination of liability. It is important to remember that western Maryland is a geographically small, rural, and mountainous landscape, offering residents a high quality of life, in part due to abundant biological, recreational, and cultural resources with exceptional value. Because of its mountainous landscape and history of coal mining, there are also many hazards in western Maryland that must be avoided in the interest of long-term well integrity and public safety. The goal of best management practices for siting MSGD-related infrastructure would be to provide a safe environment for all residents, avoid conflicts with existing land uses, and observe all on-going efforts to conserve biological diversity. Throughout this report we have recommended specific setbacks from irreplaceable natural areas, aquatic habitat, and hotspots for biodiversity (e.g., caves). Maryland has recently placed an emphasis on mapping valuable resources; this activity should continue and the resulting data should be made available to prospective drilling operators to optimize the placement of well pads and related infrastructure.

One BMP we have highlighted throughout this report is the avoidance of underground voids, which can often be justified based on caves' conservation value for many rare threatened and endangered species. Additionally, complications from encountering a cave (or deep coal mine) during drilling can jeopardize the integrity of the well, leading to an increased chance of leaks, methane contamination of underground sources of drinking water, and even blowouts. Although it is standard practice in many states to drill down through subterranean voids, our research suggests that this practice comes with important risks and at least one state has begun looking at the technique with greater scrutiny. A best practice for Maryland would be to avoid all underground voids by employing the best mapping and detection technologies and then applying additional setbacks when siting the borehole. Similarly, there are several clusters of historic conventional gas wells throughout western Maryland. Because these boreholes provide a potential conduit for gas and possibly brines to migrate upwards into underground sources of drinking water, we recommend that all portions of new unconventional gas wells (vertical and horizontal) be positioned at least ¼ mile from such boreholes. Finally, at least until it can be shown that hydraulic fracturing can be done safely within relatively close proximity to underground sources of drinking water, we recommend that Maryland prudently follow guidance from New York's experience in regulating unconventional shale gas development and not permit MSGD (or any other unconventional gas development) where the Marcellus formation is located within 2,000 vertical ft of the ground surface.

Despite best management practices designed to keep MSGD infrastructure away from our most treasured assets, there will always be impacts, which left unmitigated would adversely affect tourism, public safety, and the quality of life for residents and visitors alike. We, therefore, recommend implementing a suite of state-of-the-art mitigative techniques that would aim to limit the impact of MSGD should Maryland decide to invest fully in this new industry. The first of these techniques would seek to limit total impervious surface (e.g., pavement, buildings, gravel roads, well pads) to 2% for any watershed currently below this threshold. There is abundant scientific evidence that watershed impervious surface area is a robust indicator of cumulative impacts to watershed structure and functioning. Secondly, we recommend imposing a "no-net-loss-of-forest" requirement on MSGD. This would tend to push well pad development into non-forest areas, but also require mitigation plantings of trees whenever forests are cut to make way for MSGD infrastructure. There are many other important mitigative techniques that could be employed to reduce the overall impact of MSGD on biological, recreational, and cultural resources, and that ultimately help to maintain a high quality of life in western Maryland. These include the use of line power instead of diesel generators to protect air quality, sound barriers and visual screens to reduce the impacts of drill rigs and compressor stations, limits on hours of drilling operations to avoid peak tourism periods (e.g., hunting season for white tail deer), and thoughtful truck traffic regulation to reduce the impact of water hauling convoys on quiet rural roads. Finally, although many landowners might earn substantial profits from MSGD on their land, their neighbors who opt out should be protected from the worst impacts. Sensible zoning ordinances and reasonable property line setbacks are certainly one way to reduce conflicts, but we also recommend enhanced transparency and increased public advertising of planned drilling; no one should be surprised and concerns of all parties should be addressed fully before drilling begins.

Our review of well engineering practices revealed that the gas development industry has responded to pressure to reduce its environmental footprint by developing a suite of best management practices to maintain the integrity of each well system, isolate the well from the surrounding subsurface environment, and effectively contain the produced gas and other fluids within the well's innermost production conduit; in so doing, the gas can ultimately be transported through ancillary pipelines for processing and delivery to market, while the wastewater (i.e., "flowback", brines) that is returned to the surface can be efficiently captured, contained, treated, and ultimately recycled (while things are rapidly changing, the industry still relies very heavily on underground injection as the ultimate disposal process). The American Petroleum Institute (API)—as the technical arm of the oil and gas industry—has taken the lead in reviewing and evaluating the industry's practices for drilling, completing, and operating oil and natural gas wells; on the basis of its on-going technical reviews of various practices, API has published an extensive number of documents describing so-called "recommended practices" (RPs) which it communicates and shares with the industry. Many of these RP's explicitly address problems in maintaining well integrity and provide standards that have been expressly adopted by state regulatory authorities. If Maryland decides to begin permitting MSGD, we recommend that any operator who proposes drilling in the state should be required—at a minimum—to adopt API's RPs and standards for well planning, well design, well construction, well completion, and well decommissioning. These practices can certainly be improved upon (for example, through more widespread field testing), and we believe it is very likely that API will gradually refine its RPs pertaining specifically to unconventional shale gas development. Maryland should require all operators to employ drilling, completion, and environmental control technologies and practices that fully meet these evolving standards and that are considered up-to-date.

The current BMP for handling drilling fluids, hydraulic fracturing chemicals, wastewaters, and solid wastes on-site is through the use of a "closed-loop drilling system" in which all fluids are kept stored in watertight tanks that sit within secondary containment on lined and bermed "zero-discharge" well pads that can provide tertiary containment of contaminants and 100% retention of stormwater. All transfers of materials must be performed carefully on the pad so that any spills that occur can be quickly and fully contained. This type of drilling system—if properly designed and operated—would be expected to provide the lowest risk of contaminant leakage off-site such as might occur during extreme weather events. Under no circumstances should open pits for storage of wastes or wastewaters be allowed in Maryland. Maryland will need to carefully review its stormwater regulations as they pertain to oil and gas extraction and find a way to treat these industrial sites in the same way that other "hotspots" are treated. Operators will need to employ both "active" and "passive" stormwater management to effectively collect all water on a pad site over the entire life of drilling, completing, and producing operations to minimize soil erosion and downstream sedimentation (and avoid any inadvertent contaminant releases to the environment), although we explicitly recommend against employing any BMPs on-site that rely on soil infiltration due to the risks of groundwater contamination.

Marcellus shale gas development produces large volumes of wastewater (flowback and produced water, commonly considered brines) that must be effectively contained, treated, and either safely disposed of or reused. First of all, under no circumstances should Maryland allow discharge of any untreated or partially-treated brine, or residuals from brine treatment facilities, into the waters of the state. To protect its water supplies, Maryland should establish a goal of 100% recycling of wastewater in permitting any MSGD within the state and have a very strong preference for on-site recycling of wastewater. 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 for hydraulic fracturing at the same site (or at a nearby site). On-site water treatment and reuse would be expected to minimize overall freshwater use for MSGD and reduce the volume of waste, while dramatically decreasing truck transport and associated impacts across the region. Along these lines, the state should also explore the use of non-potable water sources (e.g., acid mine drainage that represents a legacy of past coal mining practices in the region) as a way of supplementing needed water withdrawals from the region's rivers and reservoirs. Finally, before permitting any development in the state, Maryland should carefully review the relevant regulations surrounding development and use of underground injection wells for produced water from MSGD, and at the same time evaluate the capacity of nearby states to accept produced water or residual concentrated brine from treatment of produced water.

1. General, planning, and permitting BMPs[1]

The Marcellus shale formation underlying numerous Appalachian states is considered the largest gas-bearing shale formation in the United States. The thousands of new gas wells that have been drilled in this region since 2004 are testimony to a revolution in domestic natural gas production in the US through so-called "unconventional" development that includes both modern horizontal drilling and high volume hydraulic fracturing technologies (Soeder and Kappel 2009). Unlike neighboring Pennsylvania that participated fully in the initial boom in exploration and production between 2005 and 2009 (drilling has occurred extensively both on private and public lands in Pennsylvania), Maryland (with a significantly smaller resource) chose to stay on the sidelines with an unofficial moratorium on unconventional Marcellus shale gas development (MSGD) while it studies the lessons from other states, determines whether development can go forward safely, and evaluates it options[2]. The present study of best management practices (BMPs) for Marcellus shale gas development represents an effort to determine what actual practices would provide the maximum protection of Maryland's environment, natural resources, and public safety should the state decide to move forward with development of this resource in the near future.

Only about 1.1% of the Marcellus shale gas play is in Maryland—by far the smallest portion of the 95,000 square miles of land underlain by this Devonian sedimentary formation that was deposited about 380 million years before present (USEIA 2012). We found many estimates of the gas resource contained in the Marcellus formation: (1) in 2002, the U.S. Geological Survey (USGS) estimated that the formation contained 1.9 trillion cubic feet (TCF); in 2008, Englander provided an estimate of 500 TCF; and in 2012, the U.S. Energy Information Administration (USEIA) estimated that 141 TCF remained that were technically recoverable as of January 1, 2009[3]. Obviously, no one knows exactly how much gas exists within the Marcellus Shale underlying western Maryland, nor the value of the gas given uncertainties about future supplies and demands that would in part determine pricing. It has been estimated, however, that there is a 50% chance that there is at least 1,286 billion cubic feet (BCF) present in Maryland (a "mid-case scenario") and development of this resource could support aggregate production of 710 BCF from 365 wells on private land over a 30-year period from 2016 to 2045—valued in total at more than $4B (in constant 2011 US dollars; Sage Policy Group, Inc. 2012). Regardless of whether these estimates are at all realistic, it is obvious from Pennsylvania's experience that very real economic benefits have been realized from MSGD (including generation of $413M in lease sales on 139,000 acres of state forest from 2008-2010, plus $88M in royalties from gas production of about 250 wells)[4].

As part of our research, we have carefully reviewed the current regulations governing MSGD in five other states (Colorado, New York, Ohio, Pennsylvania, and West Virginia), as well as the

[1] Chapter co-authors: Keith N. Eshleman, Ph.D. and Andrew J. Elmore, Ph.D. (both at: Appalachian Laboratory, University of Maryland Center for Environmental Science, Frostburg, MD 21532)

[2] Governor Martin O'Malley issued an Executive Order on June 6, 2011 establishing the Marcellus Shale Safe Drilling Initiative and Advisory Commission.

[3] Statistics are: MD (1.09%), NY (20.06%), OH (18.19%), PA (35.35%), VA (3.85%), WV (21.33%); USEIA 2012

[4] Ellen Shutzbarger (PADCNR), personal communication (August 17, 2012)

recommendations of many other expert panels and organizations that have reviewed both regulations and BMPs in these and other states. Where possible, we also reviewed the scientific literature to determine the proven effectiveness of different BMPs, particularly those that are used in road construction and the protection of terrestrial and aquatic habitat and biodiversity. Finally, we visited several well pads as part of some organized field trips that allowed us to gain an important visual perspective of the operations, practices, and challenges involved in conducting MSGD.

It is obvious that MSGD—if and when it comes to western Maryland—will be associated with both benefits and costs. Christopherson and Rightor (2011) describe recent MSGD in Pennsylvania and elsewhere as a classic “boom-bust cycle” that is characteristic of other extractive industries. The most evident impacts of the “boom” phase of the cycle are a very sudden and rapid increase in local economic activity due to drilling companies, crews, and gas-related businesses moving into an area to extract the gas resource. During the “boom” period, there may be some local population growth, as well as increased hiring by the construction, retail and services sectors. Local business income, tax revenues, and royalty payments to owners of mineral rights also increase dramatically during the “boom” phase of the cycle; costs to communities can rise significantly at this time, for everything from road maintenance to public safety to schools. When drilling declines or ceases entirely as the commercially recoverable resource is depleted, the cycle enters the “bust” phase in which population and jobs may quickly depart the area—leaving fewer people to support the boomtown infrastructure. Communities where drilling-related benefits have effectively ended continue to be affected by a legacy of regional industrialization (e.g., truck traffic, gas storage facilities, compressor plants, and pipelines) and the impacts that are attendant thereto. Effective planning by local and state government that moderates the rate of MSGD in a region may mitigate the negative effects of the boom-bust cycle to a considerable degree (Christopherson and Rightor 2011).

It is inevitable that there will be environmental impacts from MSGD in western Maryland throughout the “boom-bust” cycle (and perhaps beyond) and that a significant portion of these “costs” will be borne by local communities. Heavy truck traffic on local roads, noise and odors emanating from drilling sites, conflicts with outdoor recreation, diminished tourism, reduced biodiversity, and deterioration of air and water quality are some examples of the types of impacts that are likely even under the best of circumstances. While difficult to quantify in economic terms, these “costs” will ideally be greatly outweighed by the benefits of increased economic activity from the “boom-bust” cycle—otherwise it is very difficult to make a case that MSGD should occur at all. These impacts (“externalities”, in economic terms) must be expected even if best practices are implemented, local ordinances and state gas development regulations are carefully revised, and high standards of enforcement and inspection are put in place. Since these impacts are difficult to quantify in economic terms, we have explicitly chosen to identify and recommend specific BMPs that—largely on the basis of our professional judgment—would provide as much protection of Maryland’s natural, cultural, historical and recreational resources; the environment; and public safety as can reasonably be provided while allowing MSGD to move forward. The hope is that through implementation of these BMPs many of the most egregious environmental impacts can be prevented s (i.e., allowing the external costs to effectively be “internalized”).

We have also concluded from our review and from a simple geographic observation that Maryland is definitely not in control of its own environmental destiny when it comes to Marcellus shale gas development. The fact of the matter is that air and water pollutants (and even highway vehicles and U.S. dollars) are not observant of state boundaries. Since western Maryland (just two counties: Garrett and Allegany) is a relatively small "panhandle" sandwiched between Pennsylvania and West Virginia, in essence it cannot be truly isolated from activities in these and other states (e.g., some surface waters that originate in other states flow through Maryland; emissions of air pollutants from other states impact Maryland air quality; traffic, the human environment, and the economics of small towns in western Maryland are not immune from what is occurring in neighboring states). This also means that even if Maryland were to decide not to permit MSGD, there will no doubt be impacts felt in Maryland (both positive and negative) attributable to development of the resource in neighboring states that would mostly be beyond Maryland's ability to control.

Finally, we should note that the federal government has not played a major role in regulating unconventional gas development in Appalachia or elsewhere. There are several examples where federal statutes explicitly exempt unconventional gas development from federal environmental regulation. In particular, we note that oil and gas wastes are exempt from hazardous waste provisions of the Resource Conservation and Recovery Act (RCRA)—based on a determination by the U.S. Environmental Protection Agency (USEPA) that existing federal and state regulations were adequate to manage these wastes and apply RCRA Subtitle C regulation to these wastes would impose excessive costs on the energy industry (Hammer et al. 2012). Therefore, natural gas operators along with companies hauling or receiving these wastes are doing so without any requirement to meet the "cradle to grave" safeguards established under RCRA. An amendment to the Safe Drinking Water Act of 2005 excluded hydraulic fracturing activities under the definition of "underground injection" (with an exception made for fracturing fluid containing diesel fuel). Oil and gas operations are also exempt from NPDES stormwater permitting requirements under the Clean Water Act (Hammer et al. 2012). USEPA recently developed a federal rule mandating a BMP known as "green completion" as a way of capturing methane gas and reducing emissions of volatile organic compounds (VOCs) during the completion process—a practice that has been effectively used in Colorado and Fort Worth, Texas for several years.

Implementation of BMPs for Marcellus shale gas development in Maryland must begin well in advance of actual exploration, site development, and drilling to properly address a variety of issues related to environmental assessment, planning, permitting, and bonding. For purposes of this report, we have explicitly defined the term 'BMP' in the most general way here to include virtually all aspects of shale gas development (USDOE 2011). Also, while we have focused our report on Marcellus shale gas development, our recommendations are likely applicable to unconventional development of other shale formations such as the Utica as well. In this chapter, we make specific recommendations of some critical actions that must be taken if MSGD is going to go forward in Maryland in as safe a way as possible.

A. Pre-development environmental assessment

Pre-development environmental assessment for MSGD should be used to identify (1) specific environmental conditions or features that would be expected to affect development of a particular site or region and (2) the environmental resources that are likely at risk from any future development activities. The ultimate goal of the assessment is to prevent conducting development activities that would cause temporary or lasting environmental damage from MSGD. It has been proposed both in New York (NYSDEC 2011) and Pennsylvania (Marcellus Shale Advisory Commission 2011) that state regulators of MSGD develop an environmental assessment form or "checklist" as part of the permit application process that would be used to: (1) identify the environmental resources (e.g., areas with high ecological value, exceptional value waters, etc.) or features that would be relevant to developing a particular site; (2) identify the appropriate setbacks or restrictions that would control development of a particular site; and (3) determine the environmental assessment activities or baseline monitoring that would be necessary for development to go forward. In Ohio, the Department of Mineral Resources Management (DMRM) conducts a site review prior to issuing a permit to evaluate any site-specific conditions that might be attached to a permit to drill in an urban area (Ohio Legislative Service Commission 2010); Colorado Oil and Gas Conservation Commission (COGCC) maintains a website with maps of "Sensitive Wildlife Habitat" and "Restricted Surface Occupancy" areas that operators can use to determine whether a proposed oil or gas drilling site falls within such an area[5]. Maryland regulations governing oil and gas development require a reasonably extensive environmental assessment[6], although it doesn't appear to require any baseline monitoring activities as part of the process.

Pre-development activities are essential to ensuring that MSGD in Maryland is conducted as safely as possible; some of these activities can, at least in part, be based on digital maps of the most sensitive ecological resources and those habitats in greatest need of protection (see Chapters 5 and 6). These maps are a product of the state's long-term investments in environmental monitoring and resource assessment [e.g., Maryland Synoptic Stream Chemistry Survey (MSSCS); Maryland Biological Stream Survey (MBSS); etc.] and should be used as such by making them available to the public and to the industry at a dedicated website. Once these data layers are made available, a prospective shale gas developer—prior to submitting a drilling application or comprehensive drilling plan for review and approval—should be required to consult maps of (1) irreplaceable natural areas, (2) Maryland stronghold watersheds, (3) Maryland brook trout streams, (4) Tier II streams and drainages, (5) the entire stream network, and (6) other priority conservation areas to determine whether a proposed shale gas development would fall within an area that contains any "high-value assets". Such an exercise would further allow a prospective operator to quickly determine the applicable setbacks and other BMPs governing MSGD at a proposed site—thus saving considerable time and money during the planning stages of a particular project.

Given the relatively high density of sensitive ecological, recreational, historical, and cultural resources in western Maryland and a legacy of underground coal mining in the region, 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 (both active

[5] COGCC Rule 1201, Identification of wildlife species and habitats
[6] COMAR 26.19.01.06.C(3); see also www.mde.state.md.us/programs/Land/SolidWaste/ApplicationsFormsandInstructions/Documents/www.mde.state.md.us/assets/document/permit/MDE-LMA-PER066.pdf for more details (webpage accessed February 6, 2013)

and abandoned), 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 all appropriate setbacks and buffers for the proposed site; and (4) collection of two years of pre-development baseline data on underground sources of drinking water, downstream surface water, and both aquatic and terrestrial ecological resources. Several of these aspects of environmental assessment are already required under Maryland's existing oil and gas regulations, but other elements will need to be added.[7] Additional details on on-site and off-site monitoring to address MSGD impacts are provided in the following section.

B. On-site and off-site monitoring

On-site and off-site monitoring is an important aspect of MSGD that has not yet received the attention that the subject deserves. Environmental monitoring in the context of MSGD could play one or several important and legitimate roles, although generic monitoring would be unlikely to serve any particular purpose (except the purpose of making the citizenry of the state feel that resources are being adequately protected because they are being "monitored"). Too often, monitoring systems are put in place at great expense without carefully considering how monitoring data would actually be used. Depending on the specific types and ways that data are collected, monitoring can clearly address:

- environmental regulation (ensuring compliance with or documenting violations of standards and regulations);
- environmental remediation (establishing a benchmark for assessing damages and performing reclamation or restoration activities);
- environmental science (increasing process-level understanding, especially when combined with research); and
- environmental control (detecting problems and providing feedback to the process of defining best management practices)

There are virtually no comprehensive, carefully-designed, experimental studies of the impacts of MSGD on environmental resources that have been published in the literature, so scientific observations of actual impacts (or no impacts) associated with MSGD through case studies could play an important role in gaining process-level understanding (USEPA 2011)[8]. To date, most monitoring efforts have been associated with obtaining baseline water quality data from nearby groundwater wells that could be used to assess future damages from development activities, particularly hydraulic fracturing. Given that the risks to surface water quality from chemical or wastewater spills or releases are considered at least as great as those to groundwater, greater attention should be paid to benchmarking surface water quality (and continued monitoring to enable detection of water quality deterioration). However, almost no attention has been paid to

[7] COMAR 26.19.01

[8] The U.S. Environmental Protection Agency's ongoing study of the possible impacts of hydraulic fracturing comes closest to a systematic study, but it is addressing a limited number of possible impacts (drinking water resources) and has not been completed or published. Sadly, the recently released progress report in December 2012 (USEPA 2012) described a series of case studies in which many of the empirical data that would be used to test and parameterize impact models were collected after MSGD had already occurred (i.e., little or no pre-development data are available).

the use of monitoring data in improving best practices for shale gas development (USDOE 2011)[9]. In fact, many of the BMPs that we have identified in this report are based primarily on professional judgment rather than on systematic experimental testing with replication under a variety of field conditions. Our review revealed that relatively little monitoring has been done to establish baseline resource conditions prior to MSGD and subsequent monitoring of impacts may be only marginally useful. The best example of monitoring that we found is the program being developed and implemented by Pennsylvania Department of Conservation and Natural Resources (PADCNR) to address impacts of MSGD in the Pennsylvania state forests (PADCNR 2011). While this program certainly has some significant merits relative to what is being done elsewhere, it is obvious that MSGD was well underway before this program was ever fully implemented (in fact, it has still not been fully implemented even today).

Most of the baseline data that are presently being collected are for groundwater wells within a defined radius of a proposed gas well primarily to provide a benchmark for assessing damages (or as defense from presumed liability in the event that contamination is detected in the future). In Pennsylvania, for example, private water wells located within 1,000 ft of a proposed gas well are tested before drilling as part of the permitting process. Well monitoring in Pennsylvania showed post-drilling increases in bromide (Br) concentrations, suggesting that 3,000 ft is a more reasonable distance than the 1,000 ft that is currently required for both presumed responsibility and certified mail notification related to Marcellus gas well drilling (Boyer et al. 2011). Few, if any, hydrogeologists would disagree with the conclusion that sampling water wells within a 3,000 ft radius of a gas well is a pretty marginal groundwater monitoring program if the intent is to be able to detect a subsurface contaminant plume associated with a particular well integrity issue (especially in rural areas where the number of water wells may be very low or zero).

Other resources that could be impacted by development of a particular site (e.g., surface water quantity and quality, air quality, forest interior bird populations, etc.) have received even less attention, however. It is, therefore, recommended that Maryland 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 useful information for refinement of BMPs. These data should be collected at operator's expense and reported to Maryland Department of the Environment (MDE) as part of the permit application process. Although providing a detailed site-specific monitoring plan for MSGD is well beyond the scope of this project, we can provide some rough guidelines for what might constitute a realistic plan: (1) the monitoring system should be designed in a way that characterizes the extent of any site-specific impacts on- and off-site (e.g., downstream of a particular well pad; groundwater well sampling at least to the periphery of the area defined by the lateral boreholes); and (2) frequency of data collection should be adequate to quantify natural variability of conditions (e.g., monthly sampling of surface water may be appropriate, but annual sampling of groundwater quality may suffice). A draft plan that we obtained from Maryland DNR contains many of the elements that a solid, site-specific water and macro-invertebrate monitoring plan would likely include (Klauda et

[9] The report explains that developing reliable metrics for best practices for shale gas development is a major on-going task, and further advised that the industry set a goal of "continuous improvement" in best practices that would be "validated by measurement and disclosure of key operating metrics". Such validation would likely be heavily based on the collection and analysis of on-site and off-site monitoring data of specific parameters.

al. 2012). We envision that on-site and off-site monitoring would be continued through the life of the project as a means of assessing impacts, improving BMPs, and providing some process-level understanding of how resources are being affected.

Regional monitoring of environmental resources by the state is also recommended. In particular, both air quality and water quality may be impacted by cumulative MSGD over the entire region (or within a portion of the region), so a monitoring network will need to be established to address cumulative impacts both before and after development begins. As examples, the proposals to sample methane (and other constituents) in a sample of drinking water wells in western Maryland is an excellent idea that should be funded; comparable surveys of surface water quality in specific western Maryland watersheds that are likely to experience MSGD would be equally useful in establishing a regional baseline. Finally, air quality impacts are likely to occur at the regional scale, so MDE should ensure the one existing air quality monitoring station in the region is equipped with instrumentation to address primary MSGD impacts (e.g., NOx, VOC, and fine particulate concentrations). While the design and implementation of this monitoring network is crucial, it may not be necessary to build such a system from scratch. Many of the monitoring components can probably be piggy-backed onto existing monitoring and resource assessment activities (e.g., MBSS) that the state is presently conducting for other purposes.

C. Comprehensive drilling plans (CDP)

One way of attempting to minimize some of the most significant negative impacts associated with developing gas resources within an area (and possibly moderating the rate at which the resource is developed) is through a process known as comprehensive planning. It is thought that by carefully mapping the “constraints” on gas development presented by a variety of environmental and socioeconomic factors and also identifying the foreseeable oil and gas activities in a defined geographic area upfront, energy companies working cooperatively with other stakeholders (including state natural resource agencies) can come up with an integrated plan for efficiently exploiting the resource while minimizing impacts on local communities, ecosystems, and other natural resources. Under a COGCC rule[10], gas operators in Colorado have the option of proposing a Comprehensive Drilling Plan (CDP)[11] that covers multiple drilling locations within an area as a way of addressing some of these constraints; while voluntary, CDPs are definitely encouraged in Colorado and it has been concluded that the process would work better if operators would work together to develop a joint CDP to cover proposed activities of multiple operators where appropriate. Presently, one major operator is in the process of developing a CDP for 11 well pads and 200 gas wells in the Battlement Mesa area in Garfield County, CO—a community that is home for about 5,000 residents[12]. Given the fact that western Maryland is a largely intact landscape with areas of high terrestrial and aquatic biodiversity and known surface resources that are in need of special protection, a comprehensive gas development plan makes a lot of sense. Comprehensive planning could potentially be used to effectively

[10] Rule 216, 2 CCR 404-1 Practice and Procedure

[11] The term comprehensive drilling plan (CDP) is actually somewhat of a misnomer. A better term would be “comprehensive gas development plan” because it would logically include all aspects of the activity (i.e., constraints mapping for resource protection, exploration, environmental monitoring, drilling/fracking, gas transmission, transportation, planned mitigation of impacts, etc.).

[12] See http://www.oilandgasbmps.org/resources/casestudies/battlementmesa.php (webpage accessed February 6, 2013)

channel MSGD into areas that would be less disruptive for western Maryland residents and visitors and less sensitive to impacts while allowing for considerable and efficient exploitation of the gas resource. One way that this might be done effectively is by permitting development in densely "clustered" well pads in areas where sensitive resources (and communities) can be more easily avoided (e.g., see Figure 1-1).

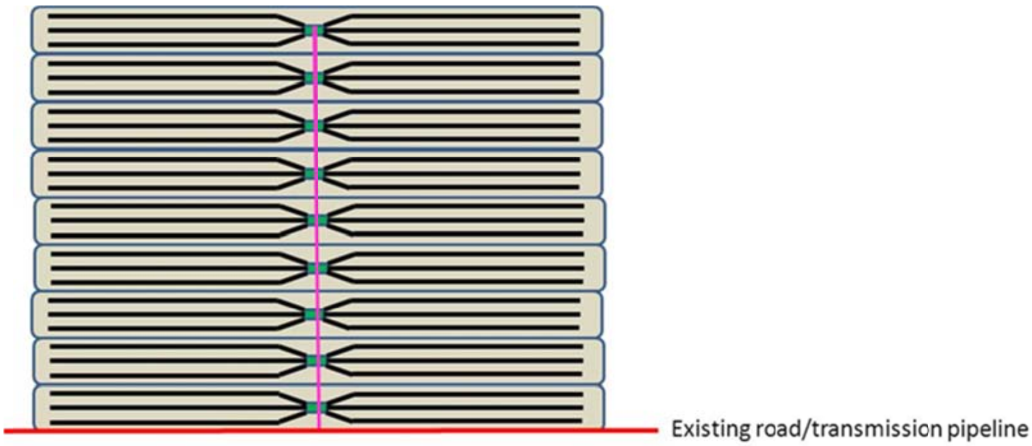

Figure 1-1. Idealized schematic (plan view) showing a "clustered" Marcellus shale gas development area comprised of nine multi-well pads (solid green boxes), each pad with six 8,000 ft laterals per pad (solid black lines) draining about two square miles of the target formation (solid tan rectangles). It is estimated that the total area of the well pads in this example is 36 acres (4 acres per pad) plus 44 acres for ancillary facilities (access road and co-located pipelines and utilities, solid chartreuse line). Total land area disturbed is less than 1% of the total area drained. With respect to setback requirements, some setbacks should be measured from the individual well pads (or disturbed areas for each pad), while others would be measured horizontally from the farthest extent of hydraulic fracturing. This idealized example obviously represents a "best-case scenario" inasmuch as local topography, streams, rivers, and structures would naturally require somewhat more surface disturbance per unit resource developed.

Since Maryland has little recent experience permitting and regulating natural gas development in the state (and no experience with modern high volume hydraulic fracturing), the state might consider putting in place regulations to support a voluntary, comprehensive gas development planning approach in western Maryland that could effectively allow MSGD to move forward at a sensible, manageable rate. We envision a voluntary program similar to Colorado's approach, but one that could also provide strong incentives for operators willing to consider this option. One way the state might incentivize CDPs could be by reducing permit fees and bonding requirements for wells covered under a CDP. Since the time to develop and have approved a CDP would likely be longer than for a single well drilling permit, overall MSGD in western Maryland might be significantly slowed (thus avoiding some of the "boom-bust" issues discussed earlier). Logically, the first approved CDP would result in permitting an area for drilling where the most sensitive resources would be less of an issue. Over time, monitoring data collected on-site, off-site, and throughout western Maryland (see Section B) would document impacts (or non-impacts) and would be used by the industry to improve BMPs. Additional CDPs would presumably be dependent upon the industry demonstrating that any impacts from earlier drilling were within acceptable limits or that newer practices were significantly better at reducing any unacceptable impacts observed in prior phases. The phasing of MSGD in this way would also allow the regulatory enforcement arm of MDE to "ramp up" as development proceeds—

gradually developing the appropriate experience over time that plays and essential role in ensuring that development is conducted as safely as possible. In Pennsylvania, for example, it took several years to staff a regulatory program within the Department of Environmental Protection (PADEP) and PADCNR to effectively address MSGD on both private and public lands. As of summer 2012, PADCNR alone had a 50 person "gas management team" that is responsible for managing the program in the state forests[13], in addition to the large number of inspectors in PA DEP that enforces permit conditions throughout the state. It is generally accepted that many of the problems that have occurred in Pennsylvania and elsewhere can be explained in part by the excessively rapid rate of MSGD before the necessary regulatory structure had been put in place.

Comprehensive drilling plans are also being used in Pennsylvania state forests and have been proposed for private lands in the state (Lien and Manner 2010); these plans involve significant interactions ("give and take") between the energy companies, state regulators, local authorities, and the public at large to get all of the various stakeholders on the same page. Through this give and take process, gas development infrastructure should be planned for in advance, even if full implementation ultimately takes many years. While we favor this approach in general, we have some reservations as to whether Maryland's regulatory structure and culture are sufficiently flexible to enable such an approach to be effectively implemented.

Another major impediment to comprehensive gas development planning in Maryland is that the state lacks the power to do "forced pooling" (or "compulsory integration" or "unitization")[14]. With forced pooling, a gas company could force one or more entities with ownership of the mineral rights of some portion(s) of a gas "unit" into a lease in order to enable more efficient exploitation of the resource (perhaps while providing greater protection of some specific surface resources overlying a portion of the unit). The practice of forced pooling is controversial and has been considered an infringement of property rights (the current Governor of Pennsylvania has called forced pooling "private eminent domain"[15]). Thirty-nine states have some type of forced pooling law, but Maryland does not. This power is particularly important given the practice of horizontal drilling, since the technology itself makes it possible to capture gas thousands of feet (horizontal direction) from a wellhead (e.g., gas resources underlying sensitive surface resources that would otherwise be impossible to extract without causing undesirable disturbances). Drilling companies have argued that forced pooling effectively enables more gas to be extracted from fewer well pads—thus reducing costs and environmental impacts. Without the power to enforce a forced pooling arrangement proposed by a drilling company, however, Maryland effectively lacks a planning tool that could be used to provide greater resource protection while allowing for efficient resource exploitation. It is not clear to us whether forced pooling would be acceptable in Maryland, given the state's legal approach to mineral rights; nonetheless, it is a topic that should be further examined.

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[13] Ibid., 5

[14] Brigid Kenney (Maryland Department of the Environment), personal communication (December 3, 2012).

[15] Reported by ProPublica: http://www.propublica.org/article/forced-pooling-when-landowners-cant-say-no-to-drilling (webpage accessed December 3, 2012)

D. Well pad spacing

Our research suggests that modern horizontal drilling and hydraulic fracturing from multi-well pads are presently capable of draining at least one or perhaps as much as two square miles of the target formation (see hypothetical example in Figure 1-1)—thus enabling the siting of well pads at locations that can avoid sensitive resources and greatly minimize disturbances and associated impacts on both terrestrial and downstream aquatic ecosystems from development. Spacing multi-well pads in dense clusters—with well pads located 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. Figure 1-2 shows an air photo of such a multi-well, multi-pad development in Pennsylvania, illustrating how the extent of surface disturbance can be minimized using this BMP. Further, our analysis suggests that—with careful and thoughtful planning (e.g., 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% of the land surface, even when accounting for the need for ancillary infrastructure such as access roads, pipelines, and compressor facilities. While this may be a "best case" scenario and there is probably no definable threshold of land disturbance below which zero impacts would be expected, it should be emphasized that disturbances of 1-2% of the land surface are quite low compared to other types of development (e.g., suburban residential, surface mining, etc.).

Figure 1-2. Air photo showing a densely-clustered well pad development in Pennsylvania. Drilled Marcellus gas wells are identified as red dots. Screen shot from web-based map viewer at http://maps.tnc.org/paenergy/ developed by The Nature Conservancy (website accessed February 8, 2013).

We also note that clustered well pad development can only be expected to reduce surface impacts if operators are held to reasonable spacing dimensions over time. In the Pennsylvania state forests, operators have agreed to drill wells as reasonably prudent as possible—although not all leases had well spacing limitations. Newer leases hold operators to a maximum number of well pad locations, or total disturbance of a predefined acreage, whichever occurs first. In these leases, if an operator wishes to deviate from the well pad numbers or acreage, a waiver and state forest approval is required (PADCNR 2011). Minimizing the number and density of well pads through coordinated planning and consultation (i.e., a CDP), as well as utilization of existing rights of way, can greatly mitigate the cumulative impacts on the landscape (Marcellus Shale Advisory Commission 2011). Given that the well pad and ancillary infrastructure will likely be in place for at least a 30-year period before final reclamation can be completed, we recommend that Maryland guard against any tendency for infilling (i.e., drilling from new pads that expands the density of the surface infrastructure within an area) by incentivizing drilling of any new wells from existing pads once these are permitted. Our concern here is for minimizing cumulative impacts that may likely prove to be a function of the total amount of surface development within an area.

E. Setback requirements

Setbacks are a primary tool by which regulatory agencies can restrict shale gas development in an effort to provide some additional protection of the most sensitive ecological resources, water resources, personal property, public property, and the health and safety of the public at large particularly in the event of an accident (e.g., pollutant spill, blow-out, etc.) during the conduct of shale gas development operations. How much protection (if any) these setbacks can provide can clearly be debated; many setbacks do not seem to be based on solid scientific reasoning or empirical data. Nevertheless, both industry and the state benefit when setbacks are clearly stated in statutes or regulations. Setbacks that are vague or that depend on subjective site analysis introduce uncertainty into the decision-making process, leading to hidden costs (redundant analyses at best and legal fees at worst). Setbacks can sometimes be voided if landowner permission is obtained (e.g., setbacks from property lines), however they are sometimes used to protect the rights of other leaseholders. Variances from setback requirements can also be granted by regulatory authorities (typically if operators propose more stringent protective drilling and/or operational practices). It should be noted that the efficacy of setbacks in providing protection for streams may be especially questionable, given the fact that the network of "blue-line" streams that appears on 7½ minute topographic maps may significantly underestimate the surface water resources at risk, especially small streams (Elmore et al. in review).

Table 1-1 provides a summary of the recommended setbacks to provide protection of specific resources in Maryland, with justification and explanation following in the appropriate chapters of the report: special siting criteria (Chapter 1); water resources (Chapter 4); terrestrial habitat and wildlife (Chapter 5); aquatic habitat and wildlife (Chapter 6); public safety (Chapter 7); cultural and historic values (Chapter 8); quality of life and aesthetics (Chapter 9); and agriculture and grazing (Chapter 10). In each case, wherever two or more setbacks apply, the most restrictive setback would take precedence.

Table 1-1. Summary of recommended setbacks for resource protection and public safety.

From	To	Distance	Chapter
Aquatic habitat (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and floodplains)	Edge of drill pad disturbance	300 ft	Chapter 5 and 6
Special conservation areas (e.g., irreplaceable natural areas, wildlands)	Edge of drill pad disturbance	600 ft	Chapter 5
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	300 ft	Chapter 8
Mapped limestone outcrops or known caves	Borehole	1,000 ft	Chapter 1 and 5
Mapped underground coal mines	Borehole	1,000 ft	Chapter 1 and 3
Historic gas wells	Any portion of the borehole, including laterals	1,320 ft	Chapter 1 and 3
Any occupied building	Compressor stations	1,000 ft	Chapter 9
Any occupied building	Borehole	1,000 ft	Chapter 9
Private groundwater wells	Borehole	500 ft	Chapter 4
Public groundwater wells or surface water intakes	Borehole	2,000 ft	Chapter 4

F. Identification of freshwater aquifers and groundwater flowpaths

Drilling for gas in the Marcellus shale formation (located 0 to 9,000 ft below the surface in western Maryland) will obviously require that operators drill vertical boreholes through the freshwater zone. Many western Maryland residents are dependent on groundwater for their drinking water[16]—underlining a critical need to identify and understand the hydrogeological setting and dynamics of the principal aquifers underlying this region *prior to* MSGD so that safe drilling practices that are protective of these systems can be implemented. The USGS reported that there are currently ten permitted water wells (mostly public supply wells) in the Deep Creek watershed in Garrett County with a reported combined average annual withdrawal of 0.28 MGD in 2007, plus an additional 2,900 permit-exempted individual wells with an estimated combined average annual withdrawal between 0.43 and 0.87 MGD.[17] Withdrawals of groundwater for public supply increased by more than 2,000% between 1988 and 2007, reflecting both population growth and expanded public service in the watershed.[18] An important issue is the depth that a surface well casing string must be placed and cemented to ensure that the fresh groundwater

[16] Estimated average daily withdrawals for self-supplied domestic use and public supply distribution in these two counties in 2000 (the most recent year for which data are available) were 2.41 million gallons per day (MGD) of surface water and 4.01 MGD of groundwater. See http://md.water.usgs.gov/freshwater/withdrawals/#ga (webpage accessed December 4, 2012).

[17] McPherson, W.S. Water use in the Deep Creek Lake watershed, Garrett County, Maryland, 1980-2007; http://md.water.usgs.gov/deepcreek/wateruse/index.html (webpage accessed December 4, 2012).

[18] Ibid.

resources can be adequately protected in the Deep Creek watershed and elsewhere. Subsequently, gas wells will have to be properly cased and cemented to protect fresh groundwater supplies (see Chapter 3). While many neighboring states have mapped the interface between saline and freshwater aquifers, Maryland has not. Water quality data from eight different projects conducted in the Northern Appalachian Coal Basin indicated total dissolved solids (TDS) levels between 2,000 and 5,000 milligrams per liter (mg/L) at depths ranging from 500 to 1,025 feet below the ground surface—values that are within USEPA's water quality criterion (< 10,000 mg/L TDS) for underground sources of drinking water (Zebrowski et al. 1991). It was reported that one deep well drilled in southern Garrett County encountered a freshwater/saltwater interface at a depth of 940 feet (Duigon and Smigaj 1985).

We were unable to find detailed digital maps of the principal freshwater aquifers of western Maryland, nor hydrogeological cross-sections or quantitative data that could be used to develop flow nets or models to infer groundwater flowpaths and other important features such as recharge areas, discharge areas, hydrologic residence times, and depth of the freshwater zone across the area. The best resource appears to be a USGS report that includes a fairly detailed description and map of the principal aquifers of the area, plus some qualitative analysis of groundwater flowpaths and quality (Trapp, Jr. and Horn 1997). There is a definite need for a comparable hydrogeological analysis focused strictly on western Maryland that could be based on measurements of static water levels from domestic and commercial wells, well water quality data, and observations reported in well logs; a map of the freshwater/saltwater interface would be a useful product from such an analysis. Provided with adequate resources, the Maryland Geological Survey (MGS) might be the logical group to undertake such an investigation.

The principal aquifers of unglaciated western Maryland include: (1) Appalachian Plateau aquifers in Paleozoic sedimentary rocks that are usually flat-lying or gently folded (especially sandstones of Pennsylvanian and Mississippian age and carbonate rocks of Mississippian age); and (2) Valley and Ridge aquifers that are often heavily folded (Paleozoic fractured sandstones and limestones are typically the most productive aquifers in these rocks). In the Appalachian Plateau in western Maryland, the principal aquifers have been identified as belonging to the Monongahela Formation, the Conemaugh Formation, the Allegheny-Pottsville Group, the Mauch Chunk Formation, the Pocono Formation, and the Greenbrier Formation (the latter is a limestone formation that is only locally water-yielding). The Monongahela, Conemaugh, and Allegheny Formations each contain multiple seams of mineable coal—most of which are economically important (Staubitz and Sobashinski 1983). In the Valley and Ridge of western Maryland, the principal aquifers are the Hampshire Formation, the Chemung Formation, and the Romney Group overlying the Oriskany Sandstone which is commonly saline (Trapp, Jr. and Horn 1997); coal seams are not considered mineable.

In the Appalachian Plateau Province it has been suggested that groundwater flow is “step-like”—following vertical pathways through fractures and horizontal pathways through fractured sandstone aquifers and coal beds. Groundwater recharge in the province is thought to be fairly low, owing to the relatively steep topography and shallow regolith. The low permeability shales underlying the Appalachian Plateau Province function as confining beds that can often give rise to flowing Artesian conditions in wells penetrating aquifers below the shales; this often occurs in wells located in the synclinal valleys of the province. Even in areas where groundwater has not been impacted by earlier oil and gas development that began as early as the 19th century, saline water can be encountered in aquifers within just a few hundred feet (or less in some cases) of the ground surface. Hydrogeologists have attributed this situation to (1) the presence of nearly flat-lying low permeability strata of shales, siltstones, clays, and dense limestone; and (2) the lack of intensely fractured formations that effectively prevent deeper circulation of freshwater to great depths below the surface. In other areas, however, shallow groundwater has been contaminated by brines that flowed upward under pressure through improperly cased or plugged oil and gas wells that penetrated deeper saline aquifers; there are other examples of fresh groundwater contamination from infiltration and percolation of brines stored in open pits (Trapp, Jr. and Horn 1997).

In the Valley and Ridge Province, it is thought that groundwater moves mostly along fractures and bedding planes, and in solution channels within carbonate rocks; the alternately folded sedimentary rocks, combined with a fluvially-dissected topography, have created a series of local groundwater flow systems that exist within the upper few hundred feet of the land surface and are effectively isolated from the intermediate and regional flow systems below. Springs (including both gravity springs from unconfined aquifers and Artesian springs from confined aquifers) are also very common in the Valley and Ridge. Thermal springs are also well known in the province (e.g., including famous Berkeley Springs, WV and Warm Springs, VA) where deeper heated groundwater is effectively channeled back to the surface by folding, faulting, and fracturing of the confined aquifers (Trapp, Jr. and Horn 1997). It appears that these “warm” springs form on the crests or limbs of anticlines, particularly where vertical permeability is enhanced at openings along bedding planes, tension fractures, open faults, or other fractures common to folded structures (Hobba, Jr. et al. 1979). Thus, there definitely are hydrogeological pathways by which groundwater heated at great depths (i.e., several thousand feet below the surface) flows upward through fault or fracture systems under pressure and discharges at surface springs in the Valley and Ridge Province. White Sulfur Spring and Black Sulfur Spring in Green Ridge State Forest may be less well-known examples of this same phenomenon.

A major concern with hydraulic fracturing is that fractures may propagate vertically upwards into the freshwater zone (or intersect with natural fractures), thus increasing the communication between the target gas formation and underground sources of drinking water (USDW), thus providing a mechanism for contamination of drinking water sources. We couldn’t find any conclusive studies documenting contamination of USDW by this mechanism; one fairly extensive study investigated hundreds of alleged occurrences of this phenomenon from hydraulically-fractured coal bed methane (CBM) deposits without drawing much of a conclusion (USEPA 2004). With respect to CBM wells, the consensus seems to be that there are two distinct mechanisms by which groundwater contamination could occur: (1) direct injection of hydraulic fracturing chemicals into a CBM formation that is in direct communication with USDW; or (2) creation of a hydraulic communication between a coal seam and an overlying or underlying aquifer by breaching a confining layer that provides natural isolation of the CBM from USDW (USEPA 2004).

Therefore, at least until it can be shown that hydraulic fracturing can be done safely within relatively close proximity to USDW, we recommend that Maryland follow guidance from New York’s experience in regulating 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 (NYSDEC 2011). While the stratigraphy of New York's Marcellus region is certainly not identical to Maryland's (the most obvious example is that New York's landscape was mostly glaciated during the Pleistocene, effectively removing many of the Pennsylvanian sedimentary formations from the profile), the basic stratigraphy of the Devonian formations is quite similar (Kostelnik and Carter 2009). 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 a reasonable margin of safety. As discussed in Chapter 3, a recent report shows data from several thousand hydraulic fracturing treatments that had been mapped in the Barnett shale in Texas using a micro-seismic method that purportedly indicate that the closest a vertical fracture came to a USDW was 2,800 ft and the typical distance was nearly 5,000 ft; data from hundreds of fracturing treatments in the Marcellus shale displayed in the same report shows a similar result (Fisher 2010). An important limitation of this interpretation is that neither analysis included any micro-seismic measurements where the target shale formation was within 4,000 ft of the surface. On the other hand, rock mechanics theory suggests that a hydraulic fracture will propagate in a direction that is perpendicular to the least principal stress. In shallow (i.e., < 1,000 ft) formations, the least principal stress is likely the overburden stress—so hydraulic fractures would be predicted to propagate primarily in the horizontal direction. In deeper reservoirs, however, the least principal stress would likely be horizontal and hydraulic fractures would thus be expected to propagate vertically (USEPA 2004). In Chapter 4 we discuss methods by which vertical propagation of fractures can be estimated.

G. Stakeholder engagement (e.g., education, town hall meetings, local community interactions, landowner and lessor protections)

Despite recommendations by the American Petroleum Institute (API) that operators proactively engage both surface owners and surface users before MSGD operations are initiated to foster understanding and alleviate concerns about hydraulic fracturing and other activities (API 2009), we found very few examples of novel approaches to ensuring that such engagement actually takes place. API recommends that operators communicate with land owners and/or surface users concerning activities planned for a particular site and provide information on the measures to be taken for safety, protection of the environment, and minimizing impacts to surface uses. We definitely support these recommendations, but feel strongly that this activity should go far beyond posting a notice in a local newspaper, which may not have the circulation of other media. State agency websites can be informative, but better approaches to stakeholder engagement would be through public forums or perhaps even via social media (e.g., Facebook). The goals of any interactions should be for transparency and increasing the flow of timely and relevant information to surface owners, users, and other stakeholders. As recommended for Pennsylvania, Maryland might consider developing a standardized stakeholder process that could be implemented as part of a comprehensive planning strategy; the goal of such a process would be to engage stakeholders and the community in the most effective ways possible, while allowing the permit review process to be expedited (Ubinger et al. 2010).

H. Special siting criteria

The practice of identifying and using special criteria for siting well pads within a region is based on the idea that some natural (e.g., geological, hydrological, etc.) or man-made (e.g., underground mining) factors may significantly increase specific risks associated with shale gas development; efforts could be made to identify such criteria prior to developing the gas resource so that operators and regulatory authorities can make use of such information during the permit application and review process. One such restriction is the topography; well pads should be sited on land with a slope of <15%. Much of western Maryland exhibits steep and rugged terrain that exceeds this slope recommendation (Figure 1-3). Steep topography increases risks associated with spills, sediment and erosion pollution, and natural hazards (landslides). While increasing the cost associated with MSGD, some operators might be tempted to drill on steep slopes. However, in conversations with industry representatives, we learned that most MSGD operators avoid slopes greater than 15%, likely making this recommendation moot[19].

Highly permeable subsurface zones—including both natural subsurface reservoirs (e.g., caves, caverns, and fractures) and man-made voids (e.g., underground mines and abandoned wells)—can provide preferential pathways by which aqueous or gas-phase contaminants could rapidly migrate away from a site in the event of a casing or cementing failure. Moreover, such voids present technical challenges and safety issues both in drilling (i.e., lost circulation of drilling fluids that could cause borehole collapse), in maintaining well control (i.e., avoiding a blowout), and in ensuring well integrity during and following cementing operations (Abbas et al. 2003/2004). Voids are very commonly encountered when drilling in southwestern Pennsylvania[20], necessitating the use of remedial cementing (i.e., cement "squeezes" from the surface, rather than normal cementing in which cement is pumped under pressure down the casing and back up to the surface through the annular space, displacing non-cement fluids and establishing a bond with the casing and the borehole wall). Cement squeezes (i.e., grouting of the annular space by pouring cement from the surface) are very time-consuming, expensive, and—most importantly—have a very low success rate and can leave a portion of the surface casing string unprotected from corrosive fluids (Abbas et al. 2003/2004).

To address these issues, the recently enacted Horizontal Well Act (H.B. 401) required the Secretary of the West Virginia Department of Environmental Protection to:

propose emergency and legislative rules pertaining to drilling in karst formations, establish designated geographic regions of the state where these provisions of the act are applicable, and establish standards for drilling horizontal wells in naturally occurring karst terrain. Drilling horizontal wells in naturally occurring karst terrain may require precautions not necessary in other parts of the state; such additional safeguards may include changing proposed well locations to avoid damage to water resources, special casing programs, and additional or special review of drilling procedures. At a minimum, the act requires operators to perform certain predrilling testing to identify the location of caves and other voids, faults and relevant features in the strata and the location of surface features prevalent in naturally occurring karst terrain such as sink holes; and provide any other requirements deemed necessary by the secretary

[19] Scott Rotruck, Chesapeake Energy, personal communication (April 27, 2012)
[20] Archie Miller (Chevron Appalachia), personal communication (July 20, 2012)

to protect the unique characteristics of naturally occurring karst terrain including baseline water testing within an established distance from a drilling site.[21]

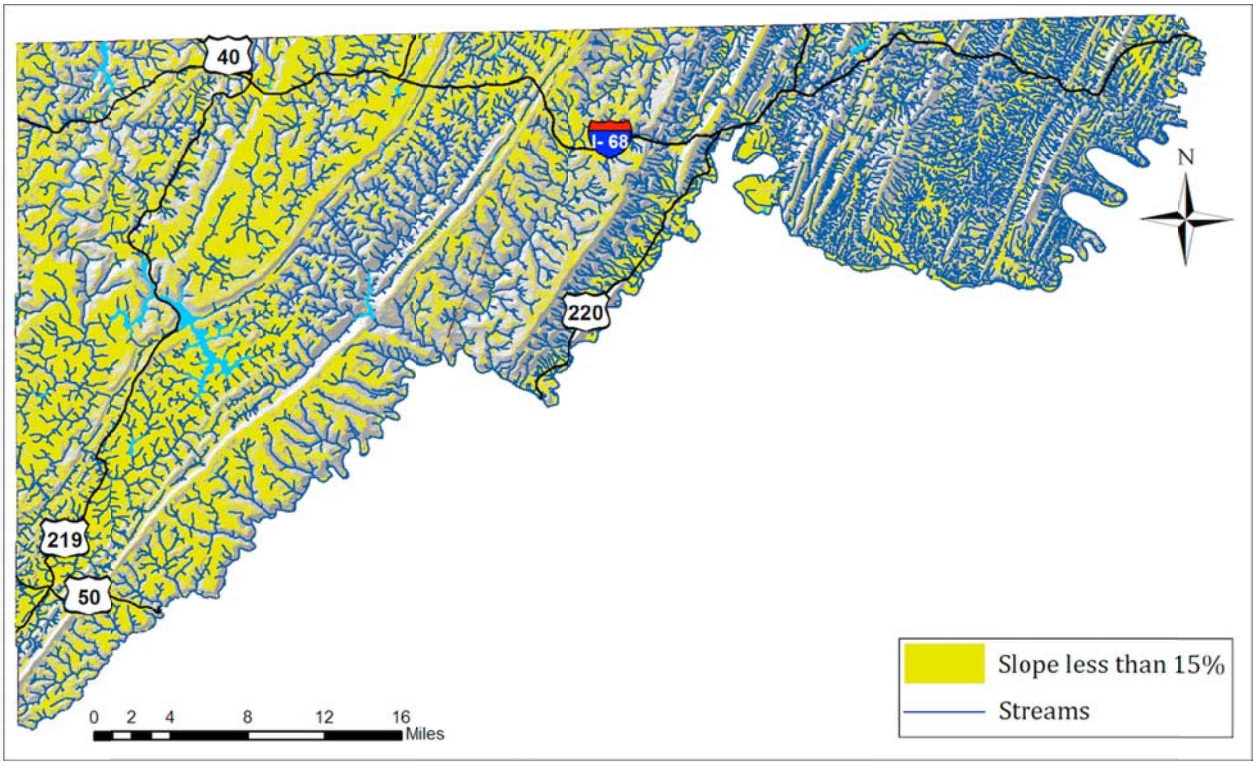

Figure 1-3. Topographic slope is a special siting criterion because it influences the effectiveness of sediment and erosion control plans and BMPs designed to protect public safety. A BMP would be restricting well pad sites to locations with a slope < 15%.

While relatively little work has been done to identify caves in western Maryland, a systematic analysis and description of known caves was completed by Maryland Geological Survey in the 1970s. As in many other environments, most of the known caves in western Maryland are considered solution caves and are associated with either the Tonoloway and Helderberg Limestones in Allegany County (east of Cumberland) or the Greenbrier Limestone in Allegany County (west of Cumberland) and in Garrett County. In Allegany County, in particular, the distribution patterns form lines (oriented southwest to northeast) that are parallel to the folds in the regional structure of the Ridge and Valley province. A band of Greenbrier Limestone crops out along the eastern flank of Dans Mountain west of Cumberland; no caves have been reported in this area, probably due to the rugged and remote terrain. Similarly, only a few caves (e.g., Crabtree and John Friends) are known to exist in Garrett County, but many more large caves likely exist; the relative sparseness of population and roads is primarily responsible for our ignorance of caves in this area (Franz and Slifer 1976). Appalachian caves—including those in western Maryland—often contain unique cave-dwelling species (including some that rare and endangered) that would best be avoided.[22]

[21] West Virginia Horizontal Well Act (H.B. 401); http://www.legis.state.wv.us/Bill_Status/bills_text.cfm?billdoc=hb401%20enr.htm&yr=2011&sesstype=4X&i=401
[22] Dan Feller (Maryland DNR), personal communication.

At the time of this report, spatial locations for 33 caves in Garrett and Allegany counties were available. These locations are aligned along relatively narrow bands in the vicinity of where limestone units crop out at the surface (Figure 1-4) with two locations falling outside of a 1000 ft buffer surrounding outcropping limestone units. Because cave systems are inherently difficult to find and map, estimates are that only 10% of caves in western Maryland are known[23]. Drilling in the vicinity (i.e., within 1,000 ft) of outcropping limestone should be considered a serious risk throughout the entire extent of limestone in western Maryland[24]. However, due to horizontal drilling techniques it should be possible to avoid drilling through these highly permeable formations and voids (both mapped and unmapped)—thus avoiding some of the most serious risks associated with poor well cementing that compromises well isolation and integrity. Consistent with the suggested requirements under H.B. 401, an obvious best practice for Maryland would be to site well pads so as to avoid vertical drilling (i.e., 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. In cases where caves or underground voids are unexpectedly encountered during drilling, the technical approaches outlined by Abbas et al. (2003-04) to ensure well isolation should be carefully applied. The technical capability to drill horizontal lateral wells many thousands of feet long under such cave systems may allow the shale gas resource to be extracted in a way that significantly minimizes the risks described above.

We have comparable concerns about MSGD in areas with extensive underground coal mine workings (both abandoned and active), gas storage fields (e.g., the Accident Gas Storage Field), and/or existing and/or orphaned oil and gas wells (see Figure 1-5). Western Maryland has a long history of underground coal mining in each of five different fields (the Lower Youghiogheny field, the Upper Youghiogheny field, the Potomac field, the Georges Creek field and the Casselman field) that has left a legacy of underground voids that present real challenges in terms of well isolation. Drilling in the vicinity of active underground coal mines represents an extreme hazard for a variety of reasons, most importantly the safety of workers who could be exposed to flammable and poisonous gases released into mine workings during the drilling process. Further, casing through these voids would require cement “squeezes” from the surface that are subject to failure. Finally, steel casing could be subjected to corrosive acid mine drainage (AMD) that might be present in abandoned underground workings, possibly leading to a catastrophic casing failure over time. For these reasons MSGD should be avoided in areas with known underground mine workings; we recommend the same 1,000 ft buffer around known workings to provide the additional margin of safety that was recommended for drilling in Karst terrain[25].

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[23] Ibid.

[24] Our recommended 1,000 ft setback was based on two observations: (1) the setback would protect *known* caves in the mapped limestone formations; and (2) since caves in the Greenbrier formation in Garrett County are expected to be confined to a weathered zone within 200 ft of the surface and the dip of these formations is approximately 20° (from the horizontal), a setback on the down-dip side of 550 ft [L = 200 ft/tan(20°)] should be adequate. Since the dip of limestone beds in Allegany County is even steeper, a setback of 550 ft would suffice. The 1,000 ft buffer *on both sides* provides an additional margin of safety due to uncertainties about the exact location of these outcrops.

[25] This additional margin of safety is justified, in part, due to the fact that the digital layer of underground mines that was used to create Figure 1-5 is likely to be only 70% complete (Jaron Hawkins, Maryland Bureau of Mines, personal communication, September 21, 2012).

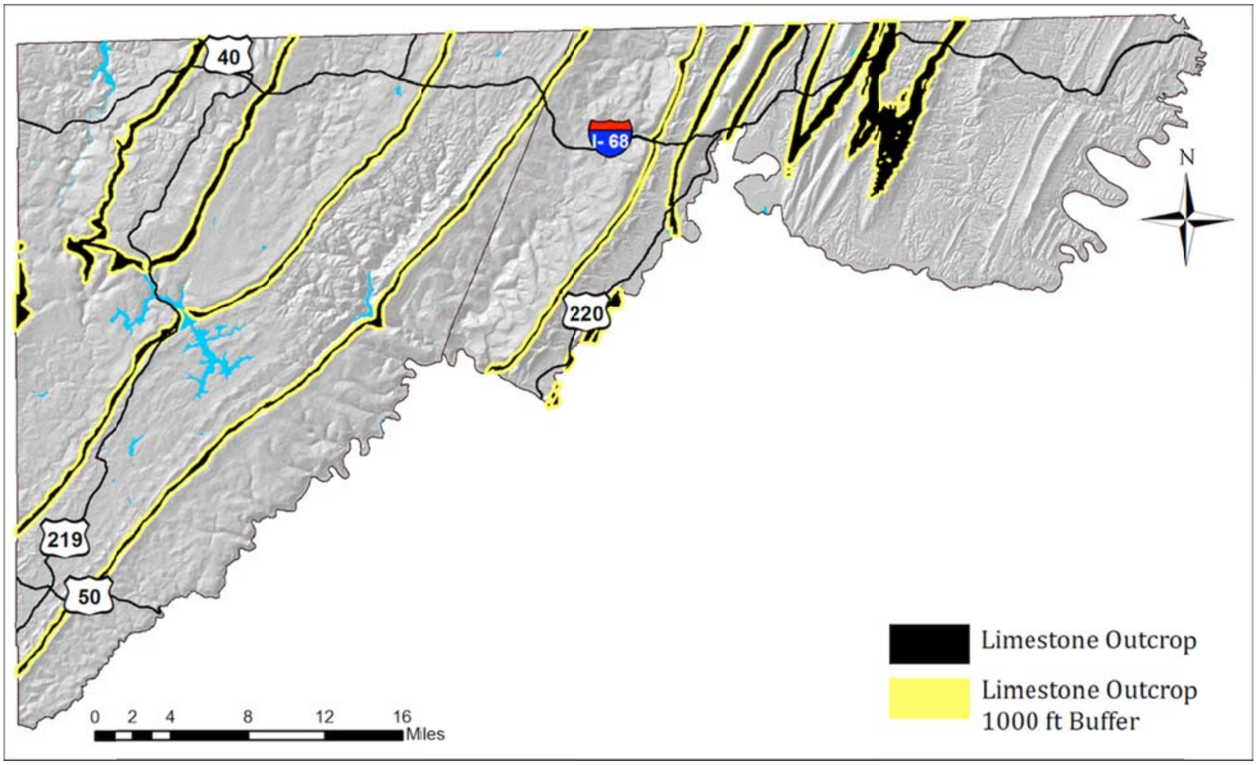

Figure 1-4. Limestone outcrops in western Maryland exist as narrow bands oriented southwest to northeast across the region. Mapped caves (not shown) are generally, but not always, located within a 1,000 ft buffer surrounding these outcrops. Rare and endemic species are at risk of disturbance by visitors to caves; therefore specific cave locations are considered sensitive information and are not included in the report. Limestone outcrops are based on a preliminary digital geological map obtained from USGS.[26]

The Accident Gas Storage Field is situated between the Casselman and Upper Youghiogheny Coal Fields covering an area of 34,000 acres; the field was discovered by the firm of Snee and Eberly in 1953 and is currently owned by Spectra Energy.[27] The principal gas formations that provide gas storage are the Hunterville chert and Oriskany sandstone of the Devonian series at an average local depth of 7,350 ft. An older reference indicated that 18 original producing wells were reworked for storage service, 35 additional wells had been drilled by 1969, and that there was a plan to increase the total number of wells to 83 for the full development of the field.[28] Presumably, Spectra Energy knows the geographic extent of the modern storage facility, the locations of individual storage wells, and the locations of any abandoned or orphaned wells within the Accident Field that would present additional MSGD hazards. These data could be used by regulators to restrict MSGD development in the vicinity of the Accident Field. Given how widespread these obstacles are to MSGD in western Maryland, we highly recommend that Maryland follow Colorado's regulation requiring identification of all potential conduits for fluid migration prior to drilling, including plugged and abandoned wells within ¼ mile of proposed

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[26] Preliminary integrated geologic map databases for the United States: Delaware, Maryland, New York, Pennsylvania, and Virginia; background information and documentation (version 1.0); USGS.
[27] http://www.spectraenergy.com/Operations/Overview-of-Operations/We-Store-Natural-Gas/
[28] Purgatorio, Jr., B.R. 1969. Design and operation of the Accident gas-storage field. American Petroleum Institute conference paper. http://www.onepetro.org/mslib/servlet/onepetropreview?id=API-69-136 (webpage accessed December 4, 2012).

coal bed methane wells, and gas seeps and springs within two miles of such wells. COGCC maintains a GIS map system that has a data layer showing bottomhole locations that the staff includes in their review of historic plugged and abandoned wells within ¼ mile (STRONGER 2011). An important best practice will be for Maryland to require setbacks from areas of previous deep coal and gas extraction. Maryland should develop a GIS 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 within ¼ mile of any section of a proposed Marcellus well should be identified as part of the permit review process. We recommend a 1,320 ft (¼ mile) setback from all historic gas wells.

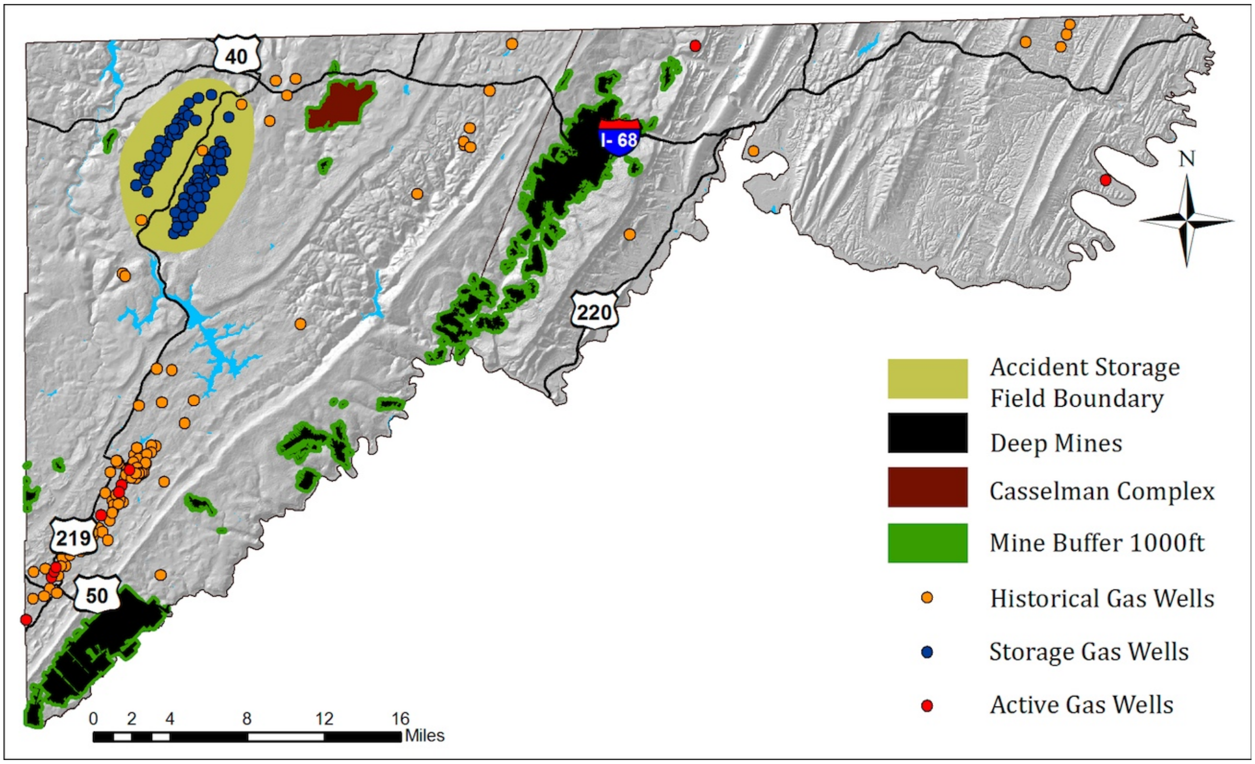

Figure 1-5. Mineral resource extraction in Maryland includes deep coal mines (both active and abandoned) and active and historic conventional gas wells. Data on abandoned and active deep coal mines, and active and historical gas wells was provided by Maryland Department of the Environment. The boundary of the Accident Storage Field was digitized from paper maps provided by Spectra Energy of Texas Eastern Transmission, LP. The size of the symbols representing the locations of gas wells have been adjusted to closely match the recommended setback of 1,320 ft provided in Table 1-1.

In addition to avoiding underground voids through implementation of these setbacks, Maryland might 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.

I. Reclamation planning

Another very important conclusion from our review of the literature and of activities in other states is that for planning purposes, MSGD infrastructure should be considered a quasi-permanent (i.e., at least 30 years) industrial addition onto a mostly rural Appalachian landscape. We have drawn this conclusion because: a) Marcellus wells are expected to produce for at least 30 years; b) it may be possible to refracture these wells in the future to enhance diminishing gas production; c) wells on multi-well pads may not be drilled in rapid succession to allow companies the ability to determine if additional drilling is warranted and justified financially; and d) established pads and associated infrastructure could possibly support future unconventional drilling into the Utica formation. In the Tiadaghton State Forest in Pennsylvania, for example, we observed that no permanent site restoration or reclamation has occurred or is planned (Figure 1-6) despite the fact that the drilling/hydraulic fracturing equipment had all moved on by the time wellhead gas prices had plummeted to less than $3 per thousand cubic feet in early 2012 (from a peak of nearly $11 in July 2008; see Figure 1-7). The thinking there is that many of the most serious impacts (i.e., erosion and stream sedimentation) are associated with earth moving and construction activities, so it makes sense both economically (for the gas companies) and environmentally (for the state) to maintain the established infrastructure rather than imposing conditions that would require multiple reclamation efforts over time at the same sites.

The quasi-permanent superposition of this industrial infrastructure onto the landscape and associated time delays until any permanent site restoration, reclamation, and well plugging takes place has important implications for how states regulate MSGD now to ensure that liabilities for reclamation and closure are properly addressed by the gas industry. The best practice for Maryland would be to develop regulations that 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. We feel strongly that the costs of reclamation should be borne directly by the operators (using resources set aside or accumulated for this specific purpose)—as opposed to ultimately passing these costs on to Maryland residents in the form of future tax liabilities and diminished natural and environmental resources (see discussion of financial assurance in Section J below).

J. Well permitting, county and state coordination, and financial assurance

Based on our review of practices in other states, it is obvious that MSGD in Maryland should require approval of a drilling permit issued by the state that addresses all possible issues associated with developing a particular site, drilling and completing a well (or wells), preventing erosion and sedimentation impacts, controlling stormwater pollution, protecting public safety, and responding to emergencies) and a mechanism for providing adequate financial assurance for decommissioning (plugging a well or wells), site reclamation, and any legacy responsibilities associated with a particular operation. All five states that we reviewed require permits and bonding for drilling gas wells, but the permitting and bonding requirements vary drastically among the different states. 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 including: (1) an

Figure 1-6. Marcellus shale natural gas infrastructure in Tiadaghton State Forest near Waterville, Pennsylvania: well pad, multiple producing wells, and produced water tanks (upper left); shallow impoundment for freshwater (lower left); and access road, utility corridor, and compressor station (right). Photos by K.N. Eshleman.

environmental assessment; (2) a certificate of liability insurance; (3) a performance bond; (4) a copy of the oil and gas lease; (5) written approval by the local zoning authority that all planning and zoning requirements have been met; (6) an approved erosion and sediment control plan; (7) an approved stormwater management plan; (8) a reclamation plan; (9) a spill prevention, control, and countermeasures plan; and (10) a drilling and operating permit plat.[29] Maryland's current regulations even allow for directional drilling (although they were clearly not written to address the practice of hydraulic fracturing); the current statutes allow for the use of pits for temporary storage of drilling fluids, but do not explicitly address impacts of water withdrawals or wastewater treatment and disposal issues. 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.

[29] COMAR 26.19.01.06 (Drilling and Operating Permit Application Procedures for the Applicant)

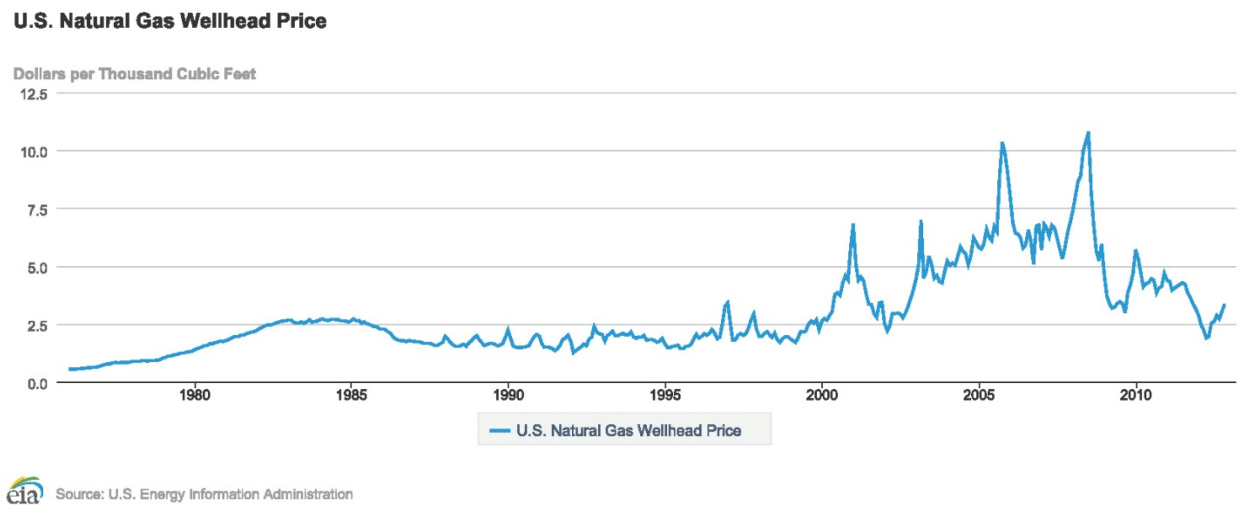

Figure 1-7. Monthly U.S. natural gas wellhead prices (1975-2012); http://www.eia.gov/dnav/ng/hist/n9190us3m.htm (webpage accessed February 8, 2013).

Local zoning could be used to avoid the most problematic conflicts among competing land uses in western Maryland, although zoning in Garrett County is not county-wide; it is restricted to a few municipal zoning districts (e.g., Deep Creek watershed). It does not appear to us that county zoning ordinances for Allegany County[30] have been modified to explicitly address MSGD. Zoning ordinances for Deep Creek watershed in Garrett County surprisingly allow for "drilling for, or removal or underground storage of natural gas" in all nine zoning subdistricts (subject to prescribed minimum setbacks and regulations of MDE, Maryland Public Service Commission, and Federal Energy Regulatory Commission)[31]. It is not clear to us that Garrett County has carefully weighed the impacts of MSGD within its zoning districts, although current restrictions for Deep Creek watershed that restrict gas development within 1,000 ft of a property boundary and within 2,000 ft of the shoreline seem reasonably restrictive.[32] 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 have identified in this report.

With respect to performance bonding, Maryland's requirements under current regulations ($100,000 per well or $500,000 blanket bond for all of an applicant's wells[33]) are relatively high compared to other states that we reviewed (e.g., Section 215 of Pennsylvania's Oil and Gas Act set bonding limits at $2,500 per well or $25,000 for a blanket bond for drilling on private land (Ubinger, et al. 2010), although limits are higher for drilling in Pennsylvania state forests). Performance bonding has been deemed inadequate for providing financial assurance for addressing decommissioning, site reclamation, and legacy responsibilities associated with MSGD (Mitchell and Casman 2011). Mitchell & Casman (2011) used Pennsylvania's experience

[30] Code of Allegany County Maryland, Part 4 Zoning (published November 25, 2002)
[31] Garrett County, Maryland; Deep Creek Watershed Zoning Ordinance (amended May 25, 2010)
[32] Ibid.
[33] COMAR 26.19.01.06.C(5)(a)

with bonding of surface coal mining sites to speculate what might be expected to occur with MSGD infrastructure in the absence of new regulations: from 1985 to 1999, bonds for surface mining permits covering about 10% of the total acreage of mineland in the state were forfeited. Since the costs to reclaim this mineland was in most cases higher than the bond amounts forfeited, the costs of bringing these abandoned minelands into compliance are inadequate and the difference must be made up by the responsible entity (in this case, the state, in some cases with help from the federal government's abandoned mineland funds).

While Maryland's performance bonding limits are comparatively high, another concern is that steep declines in gas production of these wells in tandem with increasing liabilities for decommissioning and reclamation may drive divestment of shale gas assets before expected closure occurs. The transfer of marginally-productive assets to smaller independent operators or even to surface owners is a common practice in the oil and gas industry, with the primary exploration and production companies using these divestments to fund new drilling operations. At least in Pennsylvania (not sure about Maryland), there is no formal regulatory mechanism to prevent transfers of shale gas assets to entities under conditions in which the accumulated reclamation liabilities dwarf the financial wherewithal of the new asset owners—even though these new owners would also require bonding. In some cases, these firms can obtain surety bonds for only a percentage of a bond's face value—putting much of the financial obligation on the backs of banks or surety companies who themselves would be liable for the reclamation costs down the road. Another problem with surety bonding is that underwriting firms will only market such bonds when the amount and terms of the liability are strictly defined; bonds are thus not well suited to covering unforeseen liabilities (e.g., legacy issues such as long-term replacement or treatment of a community's water supply in the event that an existing supply is lost or irrevocably contaminated). Even in the event that the costs are covered prior to release of a bond, environmental problems that arise later would be difficult for individuals, communities, or a state to address without pursing a civil action (Mitchell and Casman 2011).

We believe that Maryland's relatively high bonding limits on oil and gas well drilling may largely prevent such divestments from occurring, and may also provide adequate funding through performance bonding to address all but the most catastrophic environmental impacts (e.g., loss of a community's water supply, etc.). Typical costs of plugging Devonian shale wells and reclaiming sites in Pennsylvania are estimated to be somewhere in the range of $60,000 to $700,000 (mean of around $100,000) per well (with some economies of scale for plugging multiple wells on the same pad), so Maryland's current bond limits appear reasonable (Mitchell and Casman 2011). Nonetheless, the state might wish to reexamine whether current bonding amounts (especially the blanket amount of $500,000) are adequate to address the full range of likely decommissioning costs. If the state is going to enforce the best practice of drilling multiple (e.g., six) wells from a single pad, it isn't unlikely that a single operator could develop five pads (total of 30 wells) with a single blanket bond of $500,000 (less than $17,000 per well).

Maryland might also consider alternate mechanisms of covering decommissioning and reclamation costs through a trust fund mechanism (i.e., investing revenue from pre-drilling fees and a five-year severance tax on production) as an alternative to bonding. The obvious downside to the state for such a mechanism is the case of the underperforming well (or dry hole) that would produce inadequate funding of the trust account. This problem could be solved fairly easily through the use of a pooled trust funded through revenue from multiple operators and by regularly adjusting the severance tax rate to ensure that the pooled fund is always adequate to cover the expected cumulative liability (Mitchell and Casman 2011).

K. Key recommendations

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.

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.

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 resource. Spacing multi-well 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 (e.g., 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% 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.

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.

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.

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 groundwater flowpaths and other important features such as recharge areas, discharge areas, hydrologic residence times, and depth of the freshwater zone across the area.

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 would be to engage stakeholders and the community in the most effective ways possible, while allowing the permit review process to be expedited.

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.

1-I An obvious best practice would be to site well pads so as to avoid vertical drilling (i.e., 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.

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.

1-K Maryland should develop regulations that 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.

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.

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.

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.e., investing revenue from pre-drilling fees and a five-year severance tax on production) as an alternative to performance bonding.

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2. Protecting air quality[1]

Natural gas from MSGD has the potential to provide substantial energy economically and at a much lower cost to the atmospheric environment than the same amount of energy generated from coal combustion. In particular, natural gas (predominantly methane) has advantages over coal with respect to trapping of infrared radiation (IR) by greenhouse gases (GHGs) and contributing to planetary warming. The GHG advantage of natural gas arises from the relative heat (available for energy production) per unit of CO_2 released in combustion. For each molecule of CO_2 produced, roughly twice as much energy is available from natural gas than from coal. This advantage is only realized if the gas is combusted completely, however. In trapping IR radiation and warming the planet, methane is 30 times more potent than carbon dioxide (IPCC 2007). Therefore, if 1/30th (~3%) or more of natural gas is lost in production, processing, and transport to market, there is no *climate* advantage over coal[2]. Actual emission rates are a hotly debated subject (Armendariz 2009, Howarth et al. 2011a, Howarth et al. 2011b, Cathles et al. 2012) and can only be estimated for local operations. Nonetheless, there is some evidence that emissions rates may be significantly higher than initial estimates (Petron et al. 2012).

The specifics of the GHG calculation are as follows. Coal is roughly 80% carbon by mass; natural gas is about 90% methane. The combustion of a molecule of carbon or methane produces one molecule of CO_2, but the methane produces roughly twice as much heat represented by the enthalpy of combustion, DH°.

$$C + O_2 \rightarrow CO_2 \qquad DH° = -94 \text{ kcal/mole}$$
$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad DH° = -193 \text{ kcal/mole}$$

The ratio depends on details such as the exact composition of coal and gas but can be approximated as 193/94 = 2.05 or ~ 2. Substantial amounts of methane are released in coal mining and processing as well. If natural gas is used as a substitute for coal in electricity generation, it offers the additional advantage of higher efficiency by approximately a factor of two. But the general rule holds: natural gas is better for climate than coal as long as losses can be kept below 3% of total production.

Maryland's primary air quality issues from among all of USEPA's criteria pollutants are ozone (O_3, also called photochemical smog or Los Angeles type smog) and fine particulate matter ($PM_{2.5}$, the mass of particles less than 2.5 μm in diameter in a cubic meter of air). Maryland is in violation of the National Ambient Air Quality Standard (NAAQS: 75 parts per billion for an 8-hr average) for ozone and in or near compliance for $PM_{2.5}$, although both standards are likely to be tightened in coming years. Maryland must also comply with the Regional Haze Rule to improve

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[2] It should be noted, however, that natural gas has several other air quality benefits relative to coal, including lower emissions factors (lb/MMBTU) for nitrous oxides, sulfur dioxide, particulate matter, carbon monoxide, and mercury.

visibility or visual range. The limit to visual range is generally fine particles, so comments on $PM_{2.5}$ also apply to haze. Maryland is a member of the Regional Greenhouse Gas Initiative (RGGI) that seeks to limit emissions of pollutants that disrupt the Earth's radiative balance including carbon dioxide, nitrous oxide, and methane. On a local scale, hazardous air pollutants (HAPs), malodorous gases such as hydrogen sulfide (H_2S), and mercaptans (organic sulfur compounds) can be of concern, and radon (an α particle-emitting, respirable radioactive material produced as a decay product of radium present in the Marcellus shale formation)[3].

In terms of emissions, Maryland's top priorities are the precursors to O_3 and $PM_{2.5}$ (i.e., the chemical species that form these pollutants in the atmosphere). In the eastern U.S., both ozone and haze are considered to be secondary pollutants (made in the atmosphere by photochemical reactions of precursor gases) rather than primary pollutants (released directly into the atmosphere). Ozone forms by atmospheric reactions involving two main classes of precursor pollutants: volatile organic compounds (VOCs) and nitrous oxides (NO_X); carbon monoxide (CO) is also important for O_3 formation in polluted areas and in the remote troposphere. The formation of O_3 from these precursors is a complex, nonlinear function of many factors including: (1) the intensity and spectral distribution of sunlight; (2) atmospheric mixing; (3) concentrations of precursors in the ambient air and the rates of chemical reactions of these precursors; and (4) processing on cloud and aerosol particles (USEPA 2012). Fine particular matter ($PM_{2.5}$) are those particles (such as those found in smoke and haze) that can be deeply respired into the lungs; while the sources of these particles can be from forest fires, wood stoves, and other direct combustion sources (e.g., soot or "black carbon" emitted from the tailpipes of cars, trucks, and other on-road vehicles), they are commonly formed when gases emitted from power plants, industrial plants, and automobiles react in the atmosphere. The most common gases cited as precursors of $PM_{2.5}$ formation include: sulfur dioxide (SO_2), NO_x, VOCs, and ammonia (NH_3). Secondary formation of O_3 and $PM_{2.5}$ is thus linked by virtue of involving some of the same precursor pollutants.

High quality (dry) natural gas is composed primarily of methane (CH_4), but contains appreciable amounts (percentages) of other light alkanes such as ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and pentane (C_5H_{12}). The amounts decrease with increasing carbon number, but recent evidence indicates wide variability among MSGD wells in neighboring states. Methane and the light alkanes themselves do not contribute significantly to ground level ozone or fine particulate matter. Heavier and unsaturated volatile organic compounds (VOCs), particularly biogenic isoprene, do contribute substantially to ozone formation, however. Hazardous air pollutants (HAPs) may also arise from natural gas production. Recently, evidence indicates that some natural gas operations could be non-negligible sources of benzene (C_6H_6), a variety of other HAPs, and heavier hydrocarbons (McKenzie et al. 2012, Petron et al. 2012, personal communication: R. Schnell, Global Monitoring Division, NOAA). These could pose a health risk to individuals living within ~1000 m of a gas operation.

[3] Among different types of rocks, granites and rhyolites (igneous rocks) are most commonly enriched in uranium, but some sedimentary rocks—such as the Marcellus shale—that are rich in organic matter can be significantly enriched in uranium (and thus radium).

The purpose of this chapter is to examine the sources of pollutants and air pollution precursors associated with MSGD operations and make recommendations of best management practices that should be use to control such emissions and protect air quality in Maryland locally, regionally, and globally. Ozone and $PM_{2.5}$ are predominantly regional problems, as pollutant formation continues to occur well downwind of precursor emissions. Pollution events tend to have spatial scales of ~1000 km and temporal scales of 1-5 d. Releases of primary pollutants (particularly NO_x) in western Maryland where MSGD could occur could certainly have adverse effects on eastern Maryland where NAAQS ozone violations occur. The regional scale of these problems would suggest that even if MSGD does not go forward in Maryland, the state's air quality would be expected to be affected to some degree by activities in surrounding states; in particular, we are concerned that greater regional emissions of NO_x into a regional atmosphere upwind (i.e., west) of Maryland would be expected to make it more difficult for the state to meet the NAAQS for ozone in the future. While no studies have been published on regional air quality impacts from MSGD, one numerical atmospheric modeling study of Texas and Louisiana indicated increases in the 8-hr ozone values of up to 5 ppb as a result of natural gas development of the Haynesville Shale (Kemball-Cook et al. 2010).

A. Reducing pollutant and pollutant precursor emissions from MSGD operations

Implementation of BMPs to control air pollution emissions in Maryland—as in neighboring Marcellus shale states—would be driven largely in an effort to comply with USEPA regulations under the Clean Air Act that mandate both New Source Performance Standards (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) for oil and natural gas production. In the following subsections we describe the BMPs that could be deployed to reduce emissions of the key air pollutants (and air pollution precursors) described above.

Methane and VOCs. Determining BMPs for reducing methane and VOC emissions from MSGD is in part dependent on identifying and inventorying the specific sources of these gases within the gas sector. Again, no such studies have been conducted for the MSGD region, but a recent study of the Barnett shale region of Texas (Armendariz 2009) provides useful information that may be relevant to western Maryland. Emission sources in the gas industry can be classified as follows: (1) fugitive emissions; (2) vented emissions; and (3) combustion emissions. Fugitive emissions are unintentional leaks around seals and gaskets, leaks from underground pipelines due to from corrosion or faulty connections, or emissions that occur during the well completion process. Vented emissions are releases to the atmosphere by design or operational practice. Examples of vented emissions include: emissions from continuous process vents, such as dehydrator reboiler vents; maintenance practices, such as blowdowns; and small individual sources, such as gas operated pneumatic device vents. Combustion emissions are exhaust emissions from combustion sources such as compressor engines (Kirchgessner et al. 1997). Although there is quite a bit of uncertainty in methane emission rates both in absolute terms and expressed as a percentage of total production (Cathles et al. 2012), among the most significant emission sources of VOCs and methane are: (1) fugitive emissions during completion (Howarth et al. 2010); (2) fugitive emissions from compressor station and transmission systems (Kirchgessner et al. 1997, Howarth et al. 2010); and (3) routine venting emissions (Kirchgessner et al. 1997, Howarth et al. 2010).

One best practice that can dramatically limit both VOC and methane emissions during the well completion phase is a procedure known as a “green completion” or “green flowback process” (Armendariz 2009). In this process, performed using special equipment brought onto the well pad, gases and liquids brought to the surface during the 3- to 10-day completion process are collected, filtered, and transported into production pipelines and tanks, instead of being dumped, vented to the atmosphere, or flared. After the completion process has ended, the produced gases and liquids can be directed to permanent on-site separators (that separate gas from water and any hydrocarbon liquids), condensate tanks, and piping that had been installed at the well site; condensate tanks are sources of emissions through venting to the atmosphere. “Green completions” are considered highly cost-effective in reducing VOC and methane emissions in the Barnett Shale in Texas (Armendariz 2009) and will be required by USEPA nationwide after January 1, 2015 under NSPS for VOCs and NESHAP for oil and natural gas production.

Unfortunately, a major loophole in implementing green completions is that the process is not applicable to “exploratory” or “wildcat” drilling, because the well must be near an operational pipeline; therefore, such well completions have been exempted by USEPA from complying with this requirement. In a phased comprehensive gas development plan, Maryland could work with industry to site early pads at specific locations where “wildcatting” would be permitted; during this phase, green completions would not occur and gases would likely be flared during the completion process. Pending the outcome of this exploratory phase, construction of additional well pads and the associated pipeline and compressor infrastructure to transport gas would subsequently be coordinated in a second phase (during which green completions would be required).

Two other final rules governing VOC and methane emissions were recently instituted by USEPA: (1) use of modified (“low bleed”) pneumatic controllers for many functions between the wellhead and the point where natural gas enters a transmission pipeline; and (2) use of new storage tanks for condensate which are capable of routing VOC emissions to a combustion or flaring device. Enclosed flaring devices are highly efficient (98%) devices that can dramatically reduce VOC and methane emissions from tanks (Armendariz 2009). USEPA is also trying to address VOC emissions for natural gas processing plants through the NSPS process—in particular controlling fugitive emissions from separators, glycol dehydrators, storage tanks, and metering stations. Many of these standards promote aggressive leak detection and repairs. Leak detection at processing plants is covered by NSPS and can be performed using handheld organic vapor meters (OVMs); inspections are performed at a specified frequency under the NSPS. Natural gas that is low in high molecular weight hydrocarbons may not require such processing, and we are not sure whether such plants will be required in Maryland.

Expansion of a comparable leak detection and repair program that governs operations from wellhead to the transmission line would be considered a BMP for reducing emissions in Maryland and elsewhere, regardless of whether processing plants are necessary. Thermal imaging cameras (e.g., FLIR Commercial Systems B.V., Breda, The Netherlands) have been used to great effect in identifying hydrocarbon leaks in Houston refineries. These cameras can be mounted on aircraft to survey broad areas to identify major leaks of hydrocarbons; this approach might be applicable to identifying hydrocarbon leaks from well sites, compressor sites, and pipeline networks in the Marcellus region. The Texas Commission on Environmental Quality

(TCEQ) has identified leaks that, when repaired, saved the refinery operators substantial product loss that more than paid for the monitoring and repair actions.[4] These and many other BMPs have been advocated by USEPA's Natural Gas STAR program aimed at implementing cost-effective strategies for reducing methane emissions by the industry[5]; as proposed for New York State, best practice in Maryland would be that all operators voluntarily participate in this program and implement as many of the recommended strategies as possible (NYSDEC 2011), including: (1) reducing methane emissions from pneumatic devices in the natural gas industry; (2) reducing methane emissions from compressor rod packing systems; (3) reducing emissions when taking compressors off-line; (4) replacing glycol dehydrators with desiccant dehydrators; (5) replacing gas-assisted glycol pumps with electric pumps; (6) optimizing glycol circulation and installing flash tank separators in glycol dehydrators; (7) using efficient compressor engines; (8) using efficient line heaters; (9) using efficient glycol dehydrators; (10) re-using production brines; (11) ensuring all flow connections are tight and sealed; (12) performing leak detection surveys and taking corrective actions; (13) using efficient exterior lighting; and 14) using solar-powered telemetry devices.

***NO_x*.** Unlike VOCs and methane that are principally emitted through fugitive and venting mechanisms, NO_x is primarily a product of operating internal combustion engines. Large (1,000 horsepower, HP) diesel internal combustion engines are often used to operate drilling rigs and power hydraulic fracturing pumps, although electric drill rigs can be powered off of the electrical grid where NO_x is effectively capped at the electrical generating plant under the Clean Air Act Amendments. Smaller combustion engines are used to power compressors that produce and transport the gas through pipelines; these engines can be powered by either diesel fuel, natural gas, or electricity. An obvious best practice for controlling NO_x emissions from MSGD in Maryland would be through the use of electrical drilling rigs, hydraulic fracturing pumps, and compressor engines that are operated off of line power; Maryland should consider mandating electrically-powered equipment wherever line power is available (or could be made readily available); this alternative might be reasonably cost-effective if MSGD can be conducted primarily or exclusively in densely clustered multi-well pad developments as discussed in Chapter 1. As an alternative to this practice that would be applicable to well pad locations not easily served by line power, Maryland could require that all engines (i.e., diesel and/or spark ignited for drilling devices, pumps, compressors, trucking, etc.) used by MSGD operators meet "fleet average" standards for NO_x emissions based on USEPA 1998 standards for heavy-duty diesel highway vehicles of 4.0 g NO_x/bhp-hr[6] equivalent to 25 g NO_x/kg fuel[7]. In Texas, TCEQ has taken a similar approach in regulating NO_x emissions in the Dallas-Fort Worth metropolitan area, although TCEQ used an even more stringent emissions standard of 0.5 g NO_x/bhp-hr (Armendariz 2009). Operators would essentially have three options: (1) utilizing newer diesel engines that can meet these emission standards; (2) replacing internal combustion engines with electrically-powered motors; or (3) some combination of the two options that would expectedly be determined by cost. Either of these three options would have significant co-benefits in terms

[4] See http://www.tceq.texas.gov/airquality/barnettshale/bshale-faq and http://www.texassharon.com/2012/03/20/tceq-videos-show-voc-emissions-in-eagle-ford-shale/

[5] http://www.epa.gov/gasstar/tools/recommended.html

[6] http://www.epa.gov/otaq/standards/heavy-duty/hdci-exhaust.htm. A bhp-hr is a brake horsepower-hour (a unit of work).

[7] This is similar to observed emissions rates for in-use vehicles, but not as stringent as the 2007+ standard of 0.2 g NO_x/bhp-hr.

of reducing VOCs as well, but engines (i.e., drilling devices, compressors, trucking etc.) could also be required to meet the "fleet average" of all engines set by the USEPA 1998 hydrocarbon (HC) standards for heavy-duty diesel highway vehicles of 1.3 g HC/bhp-hr[8].

***$PM_{2.5}$*.** We recommend that Maryland require the "fleet average" of all internal combustion engines (i.e., drilling devices, compressors, pumps, trucking etc.) used in MSGD meet USEPA 1998 standards for heavy-duty diesel highway vehicles of 0.1 g PM/bhp-hr[9]. Restricting idling time and requiring use of ultra low sulfur diesel (ULSD) fuel would also be considered best practices.

Hazardous air pollutants. Hazardous air pollutants (HAPs), particularly organic HAPs, have also been reported to exist in concentrations that are a cause for concern in the vicinity of natural gas production facilities and should be monitored near any Maryland sites. The compounds of primary concern as HAPs include benzene, toluene, ethylbenzene, and xylene (i.e., BTEX), as well as formaldehyde, among others.

Radon. As discussed in Chapter 4, production brine is likely to contain elevated levels of naturally occurring radioactive material (NORM), principally radium-226 (^{226}Ra)—a radon precursor. This material may pose a hazard to workers handling the drilling and recovery equipment, so gamma and alpha radiation from production brine should be monitored at each site. The radon gas itself that is released is unlikely to pose either a health or safety hazard unless it is contained in a confined space, however. There are no effective ways of controlling the release of radon to the atmosphere other than reburying the radium source.

B. On-site and off-site air quality monitoring

If and when drilling begins in Maryland, one way the state could attempt to address regional air quality issues (i.e., ozone) associated with developing the Marcellus shale would be to develop and implement an air emissions monitoring program throughout the region as has been proposed for Pennsylvania (Lien and Manner, 2010). The program would be focused on assessing both point sources and fugitive sources of pollutants (and pollutant precursors) at well pads and at other sources resulting from natural gas production.

C. Key recommendations

2-A Require that operators in Maryland establish a methane leak detection and repair program that governs operations from wellhead to 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.

[8] http://www.epa.gov/otaq/standards/heavy-duty/hdci-exhaust.htm; this is not as stringent as the 2007+ standard of 0.14 g HC/bhp-hr and is practicable with current technology at reasonable cost.

[9] http://www.epa.gov/otaq/standards/heavy-duty/hdci-exhaust.htm; this not as stringent as the 2007+ standard of 0.01 g PM/bhp-hr and is practicable with current technology at reasonable cost.

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 $PM_{2.5}$.

2-C Require monitoring of hazardous air pollutants at well pad sites.

2-D Monitor gamma and alpha radiation of production brines.

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.

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3. Well engineering and construction practices to ensure integrity and isolation[1]

The primary goal of the oil and natural gas industry is to cost-effectively explore for and extract petroleum and natural gas from subsurface environments where such substances have formed and accumulated over geologic time—typically hundreds of millions of years. The most common approach to extracting these substances from onshore reservoirs is through the *drilling* of boreholes from the land surface to the target zone within which these substances are thought to be concentrated and then *completing* a well by hydraulic fracturing that provides a pathway for these substances to be brought to the surface in an efficient, safe, and controlled way. Obviously, well engineering and construction practices have evolved over time as operators have gained greater experience and as technological improvements have allowed. For a century or more in an era in which environmental resources were not greatly considered, the industry made very little, if any, significant effort to explore and produce oil and natural gas in ways that would be considered environmentally sound by modern standards. For example, large volumes of brine (saline water) that were brought to the surface with the oil and gas were typically stored in unlined pits that overflowed into streams and rivers or seeped into groundwater causing widespread water pollution.

In recent decades, the industry has responded to pressure to reduce its environmental footprint and many best management practices (BMPs) have been developed and employed to ensure the integrity of each well system, isolate the well from the surrounding subsurface environment, and effectively contain the produced gas and other fluids within the well's innermost production conduit so it can be successfully transported through ancillary pipelines for processing and delivery to market. Heightened environmental awareness and elevated environmental standards have also forced the industry to make substantial progress in collecting, storing, treating, and recycling of liquid drilling wastes (i.e., "flowback", brines), although the industry still relies very heavily on underground injection as the ultimate disposal process. API—as the technical arm of the oil and gas industry—has taken the lead in reviewing and evaluating the industry's practices for drilling, completing, and operating oil and natural gas wells; on the basis of its on-going technical reviews of various practices, API has published an extensive number of documents describing so-called "recommended practices" (RPs) which it communicates and shares with the industry. Many of these RP's explicitly address problems in maintaining well integrity and provide standards that have been expressly adopted by some state regulatory authorities.

Obviously, not all well construction activities go according to plan and—despite significant experience with hydraulic fracturing—there have been relatively few published data-driven studies that explicitly address the problem of transport of subsurface contaminants from hydraulically fractured horizontally-drilled gas wells into aquifers over the lifetime of a producing well (Myers 2012); the author of a white paper on the subject described the science of understanding this problem as "recent, ongoing, and incomplete" (Ingraffea 2012). The recent

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modeling study by Myers (2012) addressed movement of contaminants to surficial aquifers through natural pathways—both advective transport through porous media overlying a hydraulically-fractured shale formation and preferential transport through fractures, but significant questions have been raised regarding the assumptions and conclusions of the study (Saiers and Barth 2012). Two recent peer-reviewed studies provided circumstantial experimental evidence that methane gas and formation brine can seep out of shale formations and contaminate overlying aquifers (Osborn et al. 2011, Warner et al. 2012), but the mechanism for such contamination is unknown and any relationship to hydraulic fracturing remains unproven (Osborn et al. 2011, Davies 2011).

The Deepwater Horizon oil spill in the Gulf of Mexico in 2010 following the Macondo well blow-out is a chilling reminder of what can go wrong when well fluids cannot be isolated, contained, and controlled (in this example, due principally to a faulty cement job). The final report from the U.S. government's official investigation into the causes of this accident also highlighted a series of decisions that complicated the cementing operation, increased the risks of failure, and were major contributing factors in the blow-out and explosion on April 20, 2010 that killed 11 men working on the drilling platform and caused the subsequent spill of an estimated 4.9 million barrels of oil into the Gulf of Mexico (National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling 2011). The Deepwater Horizon incident also underlines the importance of ensuring that the activities of all subcontractors working on a particular well are coordinated and adequately supervised by the lead operator (or prime contractor).

The purpose of this chapter is to review and recommend best management practices for ensuring well integrity and isolation of unconventional Marcellus shale gas wells based on our review of API recommended practices and regulations in place in Colorado, Ohio, Pennsylvania, and West Virginia (and proposed regulations in New York State). Other best practices that are considered ancillary to well drilling, completion, and production (e.g., BMPs for containing, treating, and disposing of drilling wastes—especially "flowback" and brines) are discussed in Chapter 4.

A. Well planning

API provides a very detailed explanation of the critical need for operators to perform adequate well planning as a first step to ensuring well integrity and isolation (API 2010)[2]. The rationale for such planning is very well established from experience, and optimum well planning for constructing wells for developing the Marcellus shale gas resource in Maryland would likely include the following elements:

- evaluation of potential flow zones;
- site selection;
- hazard assessment and contingency planning;
- well control planning for fluid influxes;
- lost circulation control plans;
- regulatory issues and communications plans; and

[2] API Standard 65-Part 2 was prepared based principally on experience in the U.S. outer continental shelf and deepwater areas of the Gulf of Mexico, but the recommendations may be applicable to other offshore and onshore areas (see p. iii).

- construction designs and plans for a specific well that would include: (1) an analysis of pore pressures, fracture gradients, and required drilling fluid weights; (2) a casing plan; (3) a cementing plan; (4) a drilling plan; (5) a hydraulics plan that provides for adequate wellbore cleaning and control of static and dynamic wellbore pressures; (6) a barrier design that provides for control of all pressures that may be encountered during the life of the well; and (7) a contingency plan that addresses wellbore instability and unintended gains and losses of fluids.

Site selection is a critical aspect of well planning, and we discuss some of the primary constraints on siting a well pad and wells in Chapter 1 (other environmental criteria are discussed in Chapters 5 through 10 of the report). We are particularly concerned about drilling in areas where there is a high probability of encountering large underground voids (e.g., 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 relatively common in western Maryland and we recommend that sites with a high probability of encountering such hazards be avoided.

Another very important element of proper well planning includes appropriate regulatory review. Typically, the regulatory agency with jurisdiction for a particular well will need to review the well plan before operations can begin. All four states that we reviewed with active unconventional oil and gas development (Ohio, Pennsylvania, Colorado, and West Virginia) require some of the elements of the well plans recommended by API for offshore operations; in some cases, additional components are required. Pennsylvania's and West Virginia's requirements with respect to well planning are nearly identical, requiring information on[3]

- the anticipated depth and thickness of any producing formation, expected pressures, anticipated fresh groundwater zones and the method or information by which the depth of the deepest fresh groundwater was determined;
- the diameter of the borehole;
- casing type, whether the casing is new or used, depth, diameter, wall thickness and burst pressure rating;
- cement type, yield, additives and estimated amount;
- the estimated location of centralizers;
- the proposed borehole conditioning procedures; and
- alternate methods or materials as required by the state regulatory agency as a condition for the well permit.

Both states' well planning requirements lack any explicit attention to potential flow pathways that are addressed in Ohio's oil and gas regulations, however. Agency review of a well permit application in Ohio includes a review of wells and other potential pathways for contamination of groundwater within the minimum spacing distance for a proposed well (with the review extending along the entire lateral of a horizontal well and includes plugging records for plugged wells and casing records for other offset wells)[4]. Ohio also requires that applicants meet

[3] 25 Pa Code § 78.83a. Casing and Cementing Plan (provisions were adopted February 4, 2011, effective February 5, 2011, 41 Pa.B. 805).

[4] Ohio Administrative Code 1501:9-1-08 Well construction.

additional requirements when planning to drill in urban areas such as (1) photo imagery and location information for tanks and flow lines, and (2) notification of all property owners within a 500 ft radius around the proposed well. Ohio also requires a pre-permit on-site review in cooperation with local officials or their designees in urban areas. In general, we found that the state requirements for well planning lack many of the essential elements recommended by API such as: hazards assessment and contingency planning, plans for addressing lost circulation, and hydraulics plans for controlling all static and dynamic borehole pressures. API (2009a) also recommends that operators investigate and review the history of nearby wells for cementing problems encountered (e.g., lost returns, irregular hole erosion, poor hole cleaning, poor cement displacement, etc.) prior to drilling; computer simulation and other planning should be carried out to optimize casing and cement placement procedures. A BMP 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. API may choose to eventually develop BMPs for well planning that are specific to onshore operations, but until such practices can be determined, the adoption of the practices advocated in API Standard 65—Part 2 (API 2010) would at least ensure that a prospective operator has addressed *in writing* all of the major hazards likely to be encountered and effectively communicated these, and contingencies for addressing them, to all subcontractors and to the appropriate regulatory authorities *prior* to spudding the well. Ohio's requirement for pre-permit on-site review by state regulatory staff should also be adopted by Maryland, but this requirement should be expanded to all proposed gas wells (not just those proposed for urban areas).

B. Drilling

Constructing a Marcellus shale gas well typically requires several cycles of drilling, installing of casing strings, and cementing casing strings in place to ensure integrity and isolation. During each cycle, lengths of steel casing are installed in sequentially smaller diameters inside a previously installed and cemented casing string. Drilling the well utilizes a drill string, consisting of a drill bit, drill collars (heavy weight pipe to put weight on the bit), and sections of drill pipe. The drill string is assembled and run into the hole, and suspended at the surface from a drilling derrick or mast. The drill string is then rotated by the use of a turntable (rotary table), top drive unit, or downhole motor drive. During drilling, a fluid is normally circulated down the drill string and up the space between the drill string and the hole that: (1) provides lubrication of the drill bit; (2) removes the formation cuttings; (3) maintains control of pressures in the well; and (4) stabilizes the hole being drilled. Drilling fluid is generally a mixture of water, clays, fluid loss control additives, density control additives, and viscosifiers. Drilling fluid is a carefully monitored and controlled mixture designed to achieve best drilling results (API 2009a).

The first hole to be drilled is a conductor pipe. In some cases the conductor pipe can be driven into place like a structural piling, but in western Maryland any conductor hole would need to be drilled. A conductor hole would logically be drilled to a depth that would provide isolation from any nearby water wells or freshwater springs. The conductor hole would be followed by sequentially deeper (smaller diameter) holes drilled to install the surface casing, the intermediate casing (if necessary), and the production casing (API 2009a).

Prior to drilling, best practice would be to either slightly crown the location around the wellbore to divert fluids to a flow ditch, or construct a liquid-tight cellar at least three ft in diameter to prevent surface infiltration of fluids adjacent to the wellbore. A Marcellus shale gas well would typically begin by drilling vertically through the subsurface zone containing freshwater aquifers (both unconfined and confined) that can provide groundwater (or USDW[5]); in many areas, coal seams will also be encountered while drilling for the surface casing. Caution must be taken while drilling through this zone to adequately protect USDW from contamination, and state regulations are meant to require operators to prudently drill through fresh groundwater zones so as to minimize disturbances to such zones[6]. One way that this can be accomplished is by drilling all intervals prior to reaching a "USDW protective depth" either on compressed air, fresh water, a freshwater-based drilling fluid, or a combination of the above. Ohio, for example, requires that only additives that are suitable for drilling through potable water supplies may be used while drilling these intervals, although the Chief of the Department of Mineral Resources Management (DMRM) has the authority to require the use of a freshwater-based drilling fluid and specify its characteristics while an operator is drilling any interval prior to reaching the USDW protective depth.[7] Maryland explicitly prohibits the use of any additives to drilling liquids without approval of MDE (except under emergency conditions), and this regulation should be retained.

Figure 3-1: Horizontal drilling technology requires the ability to make a turn from vertical to horizontal drilling at depths ranging from 2,000 to 9,000 ft below the surface. These flexible drilling pipes are used to accomplish this task.

An intermediate hole (if needed) is also drilled vertically after the surface casing has been set and properly cemented—in some cases to a kick-off point that would allow a downhole motor to gradually make the turn from vertical to a predominantly horizontal direction during drilling of the production hole (Figure 3-1). An intermediate casing is typically used to isolate the well from any subsurface formations below the protective USDW depth that could cause well instability and provide protection from any abnormally pressurized subsurface zones (API 2009a). The intermediate hole would not likely be drilled "on air". Downhole motors (which operate using the hydraulic pressure exerted by the drilling fluid) are "steerable," meaning that the direction (in all dimensions) of drilling can be controlled from the surface to stay within the target formation (API 2009a). New York State has recommended that both the intermediate and production wellbores can be drilled after all freshwater aquifers have been properly sealed behind steel casing and cement (see Section C)

[5] A USDW is defined by federal statute (40 *CFR* 144.3). The term "groundwater" is more general and includes subsurface waters that do not necessarily meet the legal definition of USDW.

[6] e.g., §22-6A-24 (West Virginia Horizontal Well Act, H.B. 401)

[7] Ibid., 4

with a mud that may be either: (a) water-based; (b) potassium chloride/polymer-based with a mineral oil lubricant; or (c) synthetic oil-based. Synthetic oil-based muds are described as "food-grade" or "environmentally friendly." When drilling horizontally, mud is needed to: (a) power and cool the downhole motor and bit used for directional drilling; (b) operate the navigational tools which require mud to transmit sensor readings; (c) provide stability to the horizontal borehole; and (d) efficiently remove cuttings from the horizontal hole. Some operators can apparently drill the horizontal wellbore "on air" (i.e., with compressed air) using special equipment to control fluids and gases that enter the wellbore (NYSDEC 2011).

Air drilling has now been used extensively in the Appalachian region for both gas drilling and for drilling water wells and should probably be considered a best practice. Air drilling is a process that utilizes high pressure air rather than water as the fluid to remove the rock fragments and cool the drill bit when drilling through rock. Its principal environmental benefit is that less water is utilized during the drilling process and dry rock fragments are returned to the surface rather than a slurry of water, drilling mud, and rock fragments. Air drilling also reduces wastewater generation and subsequent treatment (Lien and Manner 2010), but it cannot always be done safely—especially under conditions in which excessive subsurface pressures and flows may be encountered that cannot be effectively be controlled without the use of a drilling liquid. In addition to cooling and cleaning the drill bit and bringing cuttings to the surface, the use of drilling mud serves another important purpose: the density (i.e., weight of the fluid volume) of the mud effectively controls the formation pressures; well pressures can be held in check as long as the mud weight is sufficient to prevent flows from the formations being drilled. As higher pressures are encountered in deeper formations, it is therefore necessary to increase the mud density to offset those pressures (King 2012).

Maryland's current oil and gas regulations state that "drilling liquid may be required when there is insufficient geological data to safely drill with air as the circulating medium"[8]. Maryland also requires that when drilling on air is permitting, sufficient liquid shall be available on-site to kill any unexpected flow from a particular well[9]. Maryland should consider the experiences gained by other states and permit air drilling of any holes (i.e., the conductor hole and surface hole) above the USDW protective depth [which API (2010) considers to be 100 ft below the deepest USDW encountered while drilling[10]), although the current regulations should be retained so that air drilling can be permitted on a case-by-case basis.[11] If and until the freshwater/saline water interface is mapped in Maryland, the state will have to rely on operators to determine when the USDW protective depth has been reached while drilling the surface hole (likely on the basis of data obtained from geophysical logs from a particular borehole). Casing setting depths should be

[8] COMAR 26.19.01.10.F

[9] COMAR 26.19.01.10.I

[10] Maryland's current oil and gas regulations require that a string of surface casing be installed in a hole which is at least 100 ft below the deepest known stratum bearing freshwater or the deepest known workable coal bed, whichever is deeper (COMAR 26.19.01.10.O(4)).

[11] On the other hand, it is important to case and cement any surface hole prior to drilling into hydrocarbon-bearing flow zones or zones which contain waters with TDS concentrations exceeding 10,000 mg/L to avoid contamination of USDW as recommended in Ohio's regulations. For this reason, in areas where USDW cannot be adequately mapped, Ohio's oil and gas regulations also allow for use of a conductor casing through the deepest useable water zone that is first cemented to the surface, followed by setting and cementing of a surface casing string through water zones that may include brackish or brine bearing zones.

specified in the drilling plan, but the actual lengths of these strings can be adjusted based on field measurements and data collected during the drilling operation (API 2009a).

We recommend Maryland develop regulations on wellbore diameter to ensure adequate spacing for equipment and instrumentation that will need to be run into the wellbore and for an adequate thickness of cement (i.e., a "sheath") inside the annular space. Ohio has some excellent regulations that require that the diameter of each section of the wellbore in which casing will be set and cemented to be at least one inch greater than the outside diameter of casing collar to be installed, unless otherwise approved[12]. Ohio also requires that any wellbore diameter shall be consistent with manufacturer's recommendations for all float equipment, centralizers, packers, cement baskets, and any other equipment that will need to be run into the wellbore[13].

C. Casing and cementing

Casing and cementing are critical elements of any well construction that must be properly designed and engineered to ultimately serve their primary purpose of providing well integrity and isolation from surrounding subsurface formations while providing a pathway by which the gas can be safely extracted over the life of the well. For this reason, both API and all five states that we reviewed have very lengthy descriptions of practices and standards that should govern these important well construction tasks. The steel casing must be capable of withstanding all the forces that are exerted on it while running it into a hole, as well as during subsequent cementing and hydraulic fracturing operations. Similarly, cementing is used to provide isolation of subsurface flow zones, provide structural support of the well, and protect the casing from corrosion. The cement must also be able to contain all pressurized fluids during all phases of drilling and operation of the well. Operators (including company engineers who design the well casings, their supervisors, and any drilling subcontractors involved in casing installation and cementing) bear the primary responsibility for ensuring that these critical tasks are carried out properly. Therefore, as noted in Section A, a critical element of a properly-executed well construction plan is a "casing and cementing plan" that is required by all five states that we examined. In many cases, state regulations require that standards (e.g., compressive strength of the cement) must be consistent with those recommended by API.

Without detailed geological characterization ("cross-sections") of the subsurface strata in western Maryland (including depths that various formations will likely be encountered, depths of the USDW/saltwater interface, etc.), it is very difficult to make anything but general recommendations for setting and cementing casing strings in place. Based on anticipated depths to the target formation, we believe it is likely that Marcellus shale gas wells in Maryland will normally require four casing strings (i.e., conductor casing, surface casing, intermediate casing, and production casing). All steel casing used in a Marcellus shale gas well should be manufactured to API specifications and meet strict requirements for compression, tension, collapse, and burst resistance, quality, and consistency (including API Spec 5CT); casing should also be designed to withstand all anticipated hydraulic fracturing pressures, production pressures, and corrosive conditions expected to be encountered. Used or reconditioned casing would only be used if it is shown to meet API standards for new casing (API 2009a). Casing and coupling

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[12] Ibid.
[13] Ibid.

threads should also meet API standards, and casing strings should be assembled to the correct torque specifications to ensure leak-proof connections. Casing centralizers should be used to properly center the casing in the hole and provide for good mud removal and cement placement in the form of a continuous sheath around the casing string. API lists recommended types of centralizers and has various formulae for determining the type, number, and best placement of centralizers along a particular casing string (API 2009a). Maryland should require that operators use casing that meets the high standards recommended by API, as well as a sufficient number of centralizers to properly center the casing in each borehole.

API also provides good recommendations of materials and practices for ensuring that the various casing strings are properly cemented in place and can provide the desired zonal isolation of different formations, including complete isolation of USDW. Best practices are for an operator to (a) provide notice to the appropriate regulatory agency at least 24 hours prior to the commencement of any cementing operations; and (b) maintain a copy of the cementing records at the well site during the drilling and completion of the well. Cementing is best achieved by pumping a cement mixture (or "slurry") down inside the casing string being cemented and circulating the cement mixture back up the outside of the casing (i.e., between concentric rings of casing or between the outermost casing and the borehole wall). Top and bottom wiper plugs are used to minimize mixing of the cement with drilling fluids inside the casing while the cement is being pumped. Zonal isolation and integrity of the well to minimize migration of fluids through the annulus are highly contingent on complete displacement of the drilling fluid by the cement mixture; complete and tight filling of the annulus with the cement mixture to the proper height above the bottom of the hole; absence of voids; and good bonding with the casing strings and borehole walls (API 2009a). Appropriate testing of cement should always be carried out by the service company to ensure that the mixture meets the criteria specified for the specific application. It is recommended that all surface casings be cemented with a continuous column from the bottom of the casing to the surface.

Most of the states that we reviewed have established recommended standards and minimum compressive strength values for cement used in oil and gas wells, and describe how tests of cement should be conducted (i.e., API RP 10 B-2 "Recommended Practice for Testing Well Cements"). As in most states, New York has proposed cementing the surface casing by the pump and plug method with circulation to the surface, with a minimum of 25% excess cement pumped, with appropriate lost circulation materials; testing of the mixing water for pH and temperature prior to mixing; cement slurry preparation to the manufacturer's or contractor's specifications to minimize free water in the cement; and no casing disturbance after cementing until the cement achieves a calculated compressive strength of 500 pounds per square inch (psi) (NYSDEC 2011). Similarly, in Ohio, cemented casing strings shall remain static until all cement has reached a compressive strength of at least 500 psi before drilling the plug, or initiating any integrity testing[14].

While cementing of both the conductor and surface casing strings should normally be completed from top to bottom, there are likely to be situations in which large underground voids are encountered during drilling that preclude circulation of cement back to the surface. Under these circumstances, it may be possible to perform a cementing operation from top to bottom (i.e., a

[14] Ibid., 4

"top job") on a conductor casing, but this approach is normally not recommended because of difficulties in isolating the various water-bearing formations and thus protecting USDW as discussed in Chapter 1. In one of its publications, API notes that "a top job should be done only as a last resort" (API 2010). If it is determined that a "top job" will be necessary, then the conductor casing should be installed as deeply as possible to protect all USDW, and it should be absolutely required that the surface casing be fully cemented from bottom to top.

API (2009) recommends that cementing of intermediate casing should also be done in the normal manner (i.e., bottom to the surface), but notes that there may be situations where this technique is unnecessary (e.g., where the surface casing string is fully protecting the USDW) or is inadvisable (e.g., where attempts to do so result in lost circulation of the slurry). According to King (2012), in cases of very long intermediate casing strings, cementing the full casing string may be ill-advised due to the risks of fracturing formations by the pressure exerted from the weight of a column of cement (nearly twice the weight of an equivalent column of water). On the other hand, cementing an intermediate string to an insufficient height may leave the annulus exposed to higher pressures from non-isolated gas-containing shales and coals that could provide a pathway for migration of gas into the outer annulus and into overlying freshwater zones (King 2012). While we were able to find relatively few published studies that explicitly address the problem of freshwater contamination resulting from overpressurization and flow through the annulus, there is one older study that addressed this problem using a modeling approach (Harrison 1985). A more recent paper hypothesizes that high methane concentrations in drinking water aquifers in Pennsylvania are most likely attributed to annular overpressurization resulting from leaky well casings rather than from hydraulic fracturing (Osborn et al. 2011), although other mechanisms are at least as plausible (Davies 2011, Jackson et al. 2011). Data from Warner et al. (2012) may also be consistent with the same mechanism whereby Marcellus Formation brine has seeped into shallow aquifers in Pennsylvania. We cannot make a clear recommendation with respect to installing and cementing intermediate casing strings; this is a situation where the best design and construction practices will be determined, in part, by the specific geological conditions that are encountered while drilling in western Maryland. At a minimum, however, 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 likely be accomplished with a single casing string, the use of multiple strings should be favored in the well design (even if this results in greater costs in casing and cementing).

Problems encountered in cementing of gas well casings have significant implications for upward contaminant migration into USDW; a recent white paper provides a description of several mechanisms by which oil and gas wells develop fluid leaks and lose their structural integrity (Ingraffea, 2012): (1) repeated pressurization of casings with open-annulus sections; or (2) high gas pressures encountering curing cement or entering open-annulus sections. Related to these problems, loss of integrity due to poor cementing can also be attributed to: (1) poor cement placement (i.e., failure to displace the mud prior to cementing or failure to generate a sufficient height of cement within the annulus to fully cover flow zones); (2) lack of centralization of the casing string; and (3) from gas migration through the cement as it sets in place (King 2012). In particular, the latter problem has apparently been known for decades, but many operators are unaware of the hazards that gases create if they are allowed to migrate sufficiently up a setting cement column, establishing a network of linked subchannels. Mud channels formed in setting cement can allow for gas or fluid migration through the annulus if these voids are continuous. Fortunately, large voids or channels are not typically continuous over long distances, but micro-annulus (hairline) cracks that allow for such migration must be detected through well logging (see Section D) and addressed accordingly (King 2012).

D. Well logging

Useful geophysical data to support MSGD in Maryland would likely be obtained from a variety of sources, particularly: (1) published geological maps of the region from USGS or private sources; (2) available well log records from previous gas and water well drilling in Maryland and surrounding states; (3) results from seismic refraction tests conducted as part of exploration activities; and (4) results from test ("pilot hole") drilling (the latter providing information for improving stratigraphic interpretation specifically through calibration of seismic data). Data from these sources would likely be sufficient to: (1) identify subsurface drilling hazards; (2) accurately assess the location of the target zone; and (3) enable the design of production wells and detailed well plans. Once drilling for production actually begins, there are many types of data that would be collected through well logging techniques to provide detailed records of subsurface properties actually encountered in the well construction process.

Open-hole logging is a method used in borehole geophysics that is conducted after drilling the hole, but before any casing is installed. Open-hole logging can provide important information on the specific depths of various formations encountered during the drilling process—and is thus very important in optimizing the well design and drilling operations. Drilling each hole to the correct depth theoretically allows casing strings to be installed at optimal locations to achieve maximum well integrity (API 2009a). Logging while drilling (LWD) technology was initially developed in the 1970s, but the technology now allows for most "open-hole" measurements to be made without lowering a suite of instruments into the borehole as part of a "wireline". With either LWD or traditional wireline technology, it is possible to accurately determine formation properties from gamma ray logs (lithology), electrical resistivity logs (hydrocarbons), neutron porosity logs (liquid-filled porosity), and density logs (bulk density)—among others; borehole caliper logs provide measurements of the size (i.e., diameter) and shape of the borehole along its length that are crucial in estimating cement volumes. Mud logging is another borehole geophysical technique which is most commonly used in the petroleum industry to determine the concentration of natural gas being brought to the surface with the drilling mud. Modern measurement while drilling (MWD) technology allows information on natural gas levels to be obtained near the drill bit, thus providing an additional level of safety for rig workers in the event that levels are observed to reach dangerous levels. It is likely that all of these types of well logging would be used in MSGD in western Maryland.

Other types of well logging occur after cementing the casing, including gamma ray logging and cement bond logging (CBL). The objectives of a cased-hole logging program are to determine the exact location of the casing, the casing collars, and the integrity of the cement job (especially as a function of location relative to various subsurface formations). CBL is an acoustic technique that works by transmitting a vibration and then recording the amplitude of the arrival signal at a detector. Casing that is not encased in cement produces a relatively high amplitude acoustic signal because the sonic energy is not very well absorbed. Conversely, casing with a good sheath of cement throughout the annular space produces a much smaller amplitude signal because the sonic energy would be much better absorbed. A variable density log (VDL) provides a graphical representation of the receiver waveform (API 2009a). Finally, newer equipment used by bond logging service companies apparently has the capacity to do segmented radial cement bond logging (SRCBL)—a technique for determining the presence and location of "mud channels" in the cement that would be indicative of poor zonal isolation. Such channels, if extensive or continuous, could provide a pathway for unintended gas or liquid flow within the annulus (King, 2012). An SRCBL can be combined with equipment for gamma ray logging, casing collar logging, and neutron logging during a single descent.[15] Additional information on the various types of cement evaluation tools that are available can be found in API TR 10TR1.

We found relatively little agreement among the states as to which well logging techniques constitute best practice. Apparently neither Pennsylvania nor Ohio require any well logging (either open-hole or cased-hole), while West Virginia requires only a CBL. Colorado requires that operators run a minimum of a: (1) resistivity log with gamma-ray or other approved petrophysical logs that adequately describe the stratigraphy of the wellbore; and (2) a CBL on all production casing or, if a production liner is used, on the intermediate casing. Colorado also requires that open hole logs shall be run at depths that adequately verify the setting depth of surface casing and any aquifer coverage and that all logs run shall be submitted with a well completion or recompletion report to the regulatory authority. New York State has proposed that a radial cement bond evaluation log or other approved method should be use to verify the cement bond on the intermediate casing and the production casing (NYSDEC 2011). 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. We found virtually no information on possible remedial actions that can be taken by an operator in the event that problems with cement bond integrity are identified through the logging process. If remedial actions cannot fully resolve cement bond integrity issues, the operator should have no recourse but to correctly plug and abandon the well in accordance with state regulations.

Maryland's current regulations[16] apparently require only electrical induction and gamma ray "open-hole" logging to determine the depth of freshwater, but they also require operators to maintain a detailed driller's log book[17] and provide MDE with a completion report within 30 days after drilling, stimulating, and well testing have been completed[18]. Such completion reports include, among other items, information on the lithology of the penetrated strata, generalized core descriptions, estimates of porosity and permeability of formations, and copies of all logs run of the well. Maryland should consider amending its regulations to require SRCBL (or equivalent casing integrity testing) and other types of logging (e.g., neutron logging) to assist with determining the depth of freshwater as part of a cased-hole program.

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[15] e.g., Tetra Technologies (2012); http://tetratec.com/index.asp?page_ID=309
[16] COMAR 26.19.01.10.O(3)
[17] COMAR 26.19.01.10.R
[18] COMAR 26.19.01.10.V

E. Pressure testing

API (API 2009a) and the five states that we reviewed all call for testing of the various casing strings after the cement has achieved the appropriate compressive strength during a pre-specified wait-on-cement (WOC) period, but prior to drilling out. These tests are known as casing pressure tests and are performed to ensure that the integrity of each casing string is adequate to meet the well design and construction objectives. Recommended pressures and holding times for these tests were not consistent among the states, and API (2009) does not provide specific recommendations. In West Virginia, for example, the regulations only state that an operator should conduct the test at a pressure more than 20% greater than the pressure expected to be exerted on the casing. Similarly, in Pennsylvania, to pass a casing pressure test, the casing must hold the anticipated maximum pressure to which the casing will be exposed for 30 minutes with not more than a 10% decrease; certification of the pressure test shall be confirmed by entry and signature of the person performing the test on the driller's log. API also recommends that formation integrity tests (also known as "shoe tests" or "leak-off tests") be performed after drilling out both the surface and intermediate casings (API 2009a). 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[19] 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.

F. Blow-out prevention

Blow-out prevention equipment (BOPE) on a rotary drilling rig is a pressure control system installed at the top of the surface casing that is designed specifically to contain and control a "kick" (i.e., an unexpected pressure resulting in the flow of formation fluids into the wellbore during drilling operations). BOPE consists of four parts: 1) a blow-out preventer stack, 2) an accumulator unit, 3) a choke manifold, and 4) a kill line. Blow-out preventers are manually or hydraulically operated devices. Within the blow-out preventer there may be a combination of different types of devices to seal off the well. A suitable BOPE should have at least two redundant (and operational) mechanisms for preventing a blow-out. Pipe rams contain two metal blocks with semi-circular notches that fit together around the outside of the drill pipe when it is in the hole to block movement of fluids around the pipe. Blind rams contain two rubber faced metal blocks that can completely seal off the hole when there is no drill pipe in it. Annular or "bag" type blowout preventers contain a resilient packing element which expands inward to seal off the hole with or without drill pipe. To be effective, BOPE systems must be maintained and in proper working order during operations; a BOPE testing program must be employed on a regular basis to ensure that the system is functioning properly if and when it is needed (NYSDEC 2011). All BOPE should have a working pressure rating that exceeds the maximum expected surface pressure; training exercises or drills should be held as necessary to ensure crew familiarity and that the BOPE is in good working order (API 2009a).

BOPE is an example of a temporary mechanical barrier for preventing loss of well control through annular flows (API 2010). It should be kept in mind that BOPE is not the only type of barrier used during drilling and completion. Columns of fluids (e.g., drilling fluids, cement

[19] COMAR 26.19.01.10.S(3)

slurries, fracturing fluids, etc.) are considered hydrostatic barriers, because they can provide hydrostatic pressure that exceeds the pore pressures of potential flow zone, thus maintaining control of flow in the annulus. Set cement is usually the ultimate barrier element, but its competency should be carefully assessed prior to removing a mechanical barrier such as BOPE. There are many other types of mechanical barriers that are used by the oil and gas industry, but we lack the technical capacity to make recommendations as to which specific types of barriers would be employed in developing Maryland's Marcellus shale gas resource.

Pennsylvania requires the use of BOPE for drilling production wells for natural gas in unconventional formations[20], but Ohio and West Virginia do not. In Colorado, the use of BOPE is required only when drilling in high density areas; otherwise it is at the discretion of the regulatory agency (COGCC). In Colorado, pressure testing of the casing string and each component of the blowout prevention equipment (if blowout prevention equipment is required) should be conducted prior to drilling out any string of casing except the conductor pipe. The minimum test pressure should be 500 psi, and that pressure should hold for 15 minutes without pressure loss in order for the casing string to be considered serviceable. Use of BOPE with two or more redundant mechanisms should be considered a best practice for MSGD in Maryland.

G. Completing and hydraulic fracturing

The production casing is normally run to the total depth of the well and—once cemented—is intended to provide: (a) total zonal isolation between the production formation and all other subsurface formations; (b) a continuous conduit to the surface for pumping hydraulic fracturing fluids into the production formation without affecting other subsurface formations; (c) a continuous conduit for containing and transporting hydrocarbons between the production zone and the surface; and (d) a secondary barrier for the production tubing and packer that are used in the final completion step (API 2009a). In the absence of using an intermediate string, New York State recommends cementing of the production casing all the way to the surface (NYSDEC, 2011). Similarly, in Ohio, when cementing the production string of a well that will be stimulated by hydraulic fracturing, and the uppermost perforation is less than 500 ft below the base of the deepest USDW, sufficient cement shall be used to fill the annular space outside the casing from the seat to the surface. Since we explicitly recommended against drilling in situations where there is less than 1,000 vertical ft between USDW and the production formation, this option should not apply in western Maryland. Recommendations by API and used by the state of Ohio both call for cementing of the production casing to a depth at least 500 ft above the highest formation in which hydraulic fracturing will be performed, however. Ohio calls for use of a cement slurry that is designed to control annular gas migration consistent with recommended methods in API (2010). However, both API (2009a) and Ohio regulations allow for "open-hole" completions and the use of production liners in some circumstances. Maryland regulators will have to work with industry to carefully evaluate the pros and cons of these different completion options.

Hydraulic fracturing (sometimes referred to as "fracking") is a well stimulation technique employed by the oil and gas industry to increase the permeability of a hydrocarbon-bearing

[20] 25 Pa Code § 78.72. Use of safety devices—blow-out prevention equipment (provisions adopted July 28, 1989, effective July 29, 1989, 19 Pa.B. 3229; amended February 4, 2011, effective February 5, 2011, 41 Pa.B. 805).

formation of low permeability and provide a pathway for hydrocarbons and other fluids to flow more easily out of a formation and, ultimately, into a wellbore. In horizontal gas wells in unconventional formations, high volume hydraulic fracturing (HVHF, or just HF for short) is normally considered an essential part of the completion process (since gas production would be too low to justify the costs of drilling and completing a well in such formations). During the HF process, fluid (normally comprised of water and a variety of chemical additives to reduce the viscosity of the water; prevent microbial growth; disinfect the water; reduce interfacial tension; inhibit scale; etc.) is pumped into the production casing of a completed well, through perforations made in the casing, and into the target formation at pressures great enough to fracture the rock (King 2012). As fluid injection continues, fractures grow throughout the target formation; as the fractures grow, a proppant (sand) is added to the fluid. Once pumping stops and excess pressure is removed, the fractures attempt to close under the weight of the overlying strata, but the proppant keeps the fractures open—effectively increasing the permeability and, ultimately, the rate of fluid migration out of the formation (API 2009a).

Technical concerns about hydraulic fracturing have tended to focus on three major issues: (1) transport of HF fluids and other contaminants (e.g., methane gas) from a fractured Marcellus formation into natural fractures where they could be transported long distances (thousands of ft) to USDW (Myers 2012, Saiers and Barth 2012); (2) induced seismic activity associated with the HF process; and (3) the specific chemical additives used in making up the HF fluid (and their toxicity). While well beyond the scope of our study of best practices to fully explore, we believe that there has been insufficient scientific study of the first issue to allow any firm conclusions to be drawn. Such studies would undoubtedly need to consider the full gamut of pathways (e.g., improperly cemented well casings) by which contaminants—both gases and liquids—either introduced or native to overpressurized formations such as the Marcellus could impact USDW. Certainly this complexity warrants continued study, both of new methods in well engineering and well completion as they become available, but also environmental data demonstrating well isolation has been successful in protecting the USDW. With respect to the second issue of induced seismic activity, we cite the recently published National Research Council (NRC) report which concluded that: (1) the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events; and (2) injection for disposal of waste water derived from energy technologies into the subsurface does poses some risk for induced seismicity, but very few events have been documented over the past several decades relative to the large number of disposal wells in operation (NRC 2012). Best practices for selecting, handling, and disposing of HF chemicals are discussed in Chapter 4.

H. Use of well development techniques other than hydraulic fracturing

New York State has performed a technical review of possible future alternative well stimulation techniques to water-based hydraulic fracturing (which could largely eliminate the need for trucking water to well sites and presumably produce less waste), but at present these techniques appear to be limited to demonstration or pilot projects in the United States and none can be considered a best practice. Unfortunately, we lack the technical capacity and necessary experience to evaluate the potential of any of these methods to replace water-based HF in the future, but we provide the following material excerpted from New York's draft assessment document (NYSDEC 2011) as an aid to state regulators that may wish to explore these options in the future:

- ***Liquid CO_2.*** The use of a liquid CO_2 and proppant mixture obviously reduces the use of other additives. Once CO_2 vaporizes, it leaves only the proppant in the fractures. The appropriate level of environmental review for this alternative, if proposed in New York, would need to be determined at the time of application.
- ***Nitrogen-based foam.*** Nitrogen-based foam fracturing was used in vertical shale wells in the Appalachian Basin until recently. Nitrogen gas is unable to carry appreciable amounts of proppant and the nitrogen foam was found to introduce liquid components that can cause formation damage.
- ***Liquified petroleum gas (LPG).*** More recently, New York looked into the use of LPG (primarily propane) which has the advantages of carbon dioxide and nitrogen noted above; additionally, LPG is known to be a good carrier of proppant due to the higher viscosity of the propane gel. Further, mixing LPG with natural gas apparently does not "contaminate" natural gas and the mixture may, therefore, be flowed directly into a gas pipeline and separated at the gas plant and recycled. LPG's high volatility, low weight, and high recovery potential make it a particularly good fracturing agent. Use of LPG as a hydraulic fracturing fluid also inhibits formation damage which can occur during hydraulic fracturing with conventional fluids. Using propane not only minimizes formation damage, but also eliminates the need to source water for hydraulic fracturing, recover flowback fluids at the surface, and dispose of the flowback fluids. As a result of the elimination of hydraulic fracturing source water, truck traffic to and from the well site could be greatly reduced. Finally, since LPG is less reactive with the formation matrix, it is less likely that this technique would mobilize constituents that are ultimately discharged with the flowback fluid (NYSDEC 2011).

I. Determining the extent of induced fractures

There are two methods that can be used for determining the extent of induced vertical fracture growth by hydraulic fracturing. The first technique is through the use of either surface or downhole tiltmeters that are capable of measuring extremely small changes in the inclination of the Earth's surface from level. Historically, tiltmeters have been used extensively for monitoring volcanoes, the responses of dams to filling, and small movements of potential landslides, but extremely sensitive (nanoradian) surface and downhole tiltmeters developed in the 1970s by Pinnacle (a Halliburton subsidiary) now allow for fracture mapping from either offset wells or from the surface; a new generation method can apparently map induced fractures from an active fracture well in real-time (API 2009a). The second technique produces a map of vertical fracture height growth based on data from passive micro-seismic monitoring that is capable of triangulating the sounds made by rock breaking up during shear fracturing. Micro-seismic measurements are typically made with: (1) a 200 to 400 ft long set of geophones placed in an offset well located within a few hundred ft of the well being fractured; or (2) an array of microphones placed at the surface. Micro-seismic monitoring makes it possible to determine such critical hydraulic fracturing parameters as vertical extent, lateral extent, azimuth, and fracture complexity (API 2009a).

Micro-seismic data (from more than 3,000 HF applications) from Pinnacle (Fisher 2010, reprinted by King 2012) shows vertical fracture growth in hydraulically-fractured Barnett Shale wells typically extends hundreds to thousands of ft above and below the frac depth, but in no case was fracture growth observed closer than 2,800 vertical ft from USDW. Comparable data (from more than 300 fracs with micro-seismic data) from Pinnacle (Fisher 2010, reprinted by King 2012) suggest that the closest measured approach of Marcellus shale fractures in Pennsylvania to USDW was 3,800 vertical ft. As discussed in Chapter 1, these results generally support our recommendation that Maryland follow guidance from New York's experience with unconventional shale gas development and not permit MSGD (or any other unconventional gas development) where the target formation occurs within 1,000 vertical ft of USDW or within 2,000 vertical ft of the ground surface (NYSDEC 2011).

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 (API 2009a). There are no micro-seismic monitoring protocols or criteria established by regulatory agencies that are specific to HVHF. Nonetheless, operators can employ micro-seismic methods to monitor the hydraulic fracturing process and thus optimize the results for successful gas recovery. It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process. Best practice would suggest that operators place multiple receivers on a wireline array in one or more offset borings (e.g., a new, unperforated well or an older well with production isolated) or in the treatment well during the HVHF process. At least one receiver should be in the treatment zone, with another located above and one below this zone. Maximum observation distances for microseisms should be within approximately 2,500 ft of the treatment well, with the distance dependent on formation properties and background noise levels. Locations are triangulated using the arrival times of the various *p*- and *s*-waves to the receivers in these wells, and using the formation velocities to determine the location of the microseisms. A multi-level vertical array of receivers can be used if only one offset observation well is available. The induced fracture is interpreted to lie within the envelope of mapped microseisms (NYSDEC 2011). We highly recommend that a sufficient number (at least tens) of tiltmeter or seismic surveys be performed as part of MSGD in Maryland, so that the extent, geometry, and location of Marcellus fracturing can be adequately characterized. The goal would be to feed useful information back to the operators, so that subsequent hydraulic fracturing could 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.

J. Plugging

The purpose of plugging a well is to: (1) prevent interzonal migration of fluids; (2) prevent contamination of freshwater aquifers, surface soils, and surface waters; and (3) conserve hydrocarbon resources either in the production zone or in potential production zones. Generally, contamination by an improperly plugged or abandoned well can occur in two ways: (1) the abandoned well can act as a conduit for fluid flow between penetrated strata, into USDW, or to the surface; or (2) contaminated water can enter the abandoned wellbore at the surface and migrate into USDW. Such contamination can be prevented by properly plugged a well. It should be noted that while plugging operations can prevent an abandoned well from becoming a conduit for contamination, well construction and completion methods also contribute to the prevention of contamination (API 2009b). Plugging should be considered a critical element of the well decommissioning process that also includes land reclamation.

Well plugging operations are focused primarily on protecting USDW, isolating downhole formations productive of hydrocarbons or used for injection, and protecting surface soils and surface waters. A surface plug prevents surface water runoff from seeping into the wellbore and migrating into USDW cement plugs isolating hydrocarbon and injection/disposal intervals and a plug at the base of the lowermost USDW accomplishes this primary purpose. Surface water entry into an abandoned well is a concern because the water may contain contaminants from agricultural, industrial, or municipal activities. It is, therefore, recommended that operators set a cement plug at the base of the lowermost freshwater aquifer or USDW during plugging and abandonment operations applicable to the well. (NOTE: The cement plugs also work to protect surface soils and water from wellbore fluids by confining those fluids in the well.) In addition to the cement plugs described herein, many state and federal regulatory agencies require cement plugs across the base of the surface casing and in, or between, each producing and potential producing zone (API 2009b).

All formations bearing usable quality water, oil, gas, or geothermal resources (e.g., coal seams) should be protected and/or isolated. The prevention of gas or fluid migration to other zones or to the surface is of primary importance. Open-hole plugs, casing plugs, or cement squeezed through casing perforations will isolate the target formations in most cases. However, special procedures, such as perforating casing and circulating cement, may be necessary to isolate that potential production or injection formations behind any uncemented or poorly cemented casing. It is important to prevent interzonal flow in an abandoned well so that such cross-flow does not interfere in the commercial exploitation of the zones through nearby wellbores. The operator should also: (1) set the required surface plugs; (2) remove the wellhead; (3) weld a steel plate on the surface casing stub; (4) fill in any well cellar; and (5) level the area. Casing strings left in the well should be cut off at least 3–6 ft below ground level (API 2009b).

Pennsylvania[21] and Colorado[22] have enacted regulations governing plugging of gas wells that appear to be consistent with API's recommended practices, but West Virginia and Ohio have not. Maryland also has what appear to be excellent regulations[23] that are consistent with API recommendation for plugging of wells. Given the long expected time lags (of the order of 30 years or more) between drilling and well decommissioning, the biggest problem that we anticipate with plugging of Marcellus wells in Maryland will be ensuring that the appropriate party is held accountable and has sufficient assets to do so. The costs associated with plugging wells that were poorly constructed in the first place can be extremely high (Mitchell amd Casman 2011), reinforcing the need to ensure that any Marcellus shale gas wells in Maryland are constructed to the highest standards.

[21] 25 Pa. Code § 78.92 (relating to wells in coal areas—surface or coal protective casing is cemented); 25 Pa. Code § 78.93 (relating to wells in coal areas—surface or coal protective casing anchored with a packer or cement); 25 Pa. Code § 78.94 (relating to wells in noncoal areas—surface casing is not cemented or not present); 25 Pa. Code § 78.95 (relating to wells in noncoal areas—surface casing is cemented); and 25 Pa. Code § 78.407 (relating to plugging gas storage wells).
[22] COGCC Rule 319, Abandonment.
[23] COMAR 26.19.01.12

K. Key recommendations

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.

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 (e.g., 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.

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 (e.g., 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.

3-D 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.

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.

3-F Use of BOPE with two or more redundant mechanisms should be considered a best practice for MSGD in Maryland.

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, 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.

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.

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4. Protecting water resources[1]

Water is central to the advancements in shale gas recovery that have revolutionized domestic natural gas resources in the past decade. High volume hydraulic fracturing (HVHF) with chemically-amended water enables extraction of large reserves previously considered economically unviable. Significant amounts of water are required for the process, and significant amounts of wastewater are produced. Wastewaters (commonly called flowback and production waters) are contaminated with anthropogenic chemicals associated with the hydraulic fracturing process and with naturally-occurring chemicals associated with the shale formation. The possible impacts of shale gas development on regional water resources (i.e., quantity and quality) must be considered at all phases of the life-cycle of well and gas field development. Figure 4-1 provides a life cycle representation for shale gas development at a single pad. The general concerns for freshwater resources and the generation of wastewater are presented, aligned with when they occur in the life cycle of development. Some aspects of potential water impacts (e.g., land clearing and stormwater runoff) can be generalized as associated with the development of any industrial site. Other aspects (e.g., concerns with managing chemicals and preventing spills) are specific to activities that use large quantities of chemicals in the open, frequently under suboptimal climatic conditions. Finally, other concerns (e.g., concerns regarding casing and management of produced brine) are specific to oil and gas drilling operations.

A critical point shown in Figure 4-1 is that many potential impacts occur throughout development until closure (e.g., generation and management of surface runoff from the site), while other concerns (e.g., the effect of drilling on groundwater resources) may occur during a limited period of time. Further, there are additional concerns at the level of the entire resource development (the play) that must also be considered. The distributed nature of the activity (i.e., potentially hundreds of locations in western Maryland) raises specific issues with respect to watershed-wide effects. For example, it is important to consider the cumulative impact of water withdrawals for multiple wells and multiple pads, as well as the total volume of wastewater that will be generated by the formation once many hundreds of wells are in production.

This chapter provides a summary of recommendations based on a review of the actual and proposed best management practices (BMPs) for shale gas development (MSGD[2]) related to water acquisition and wastewater management in five states (WV, OH, PA, NY, and CO). Most of the practices either adopted or considered by Pennsylvania and West Virginia are applicable to Maryland, where geology, hydrology, and topography are very similar. Some practices that have been routinely employed in western states (e.g., evaporative concentration of wastes in open impoundments) are inappropriate for the mid-Atlantic region and cannot be recommended. We have also addressed some of the key regulatory and policy aspects in addressing water/wastewater issues associated with MSGD in Maryland.

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[2] As elsewhere in this report, MSGD refers to Marcellus shale gas development. However, our review of actual and proposed BMPs in the five states covered all shale gas development, regardless of the target formation.

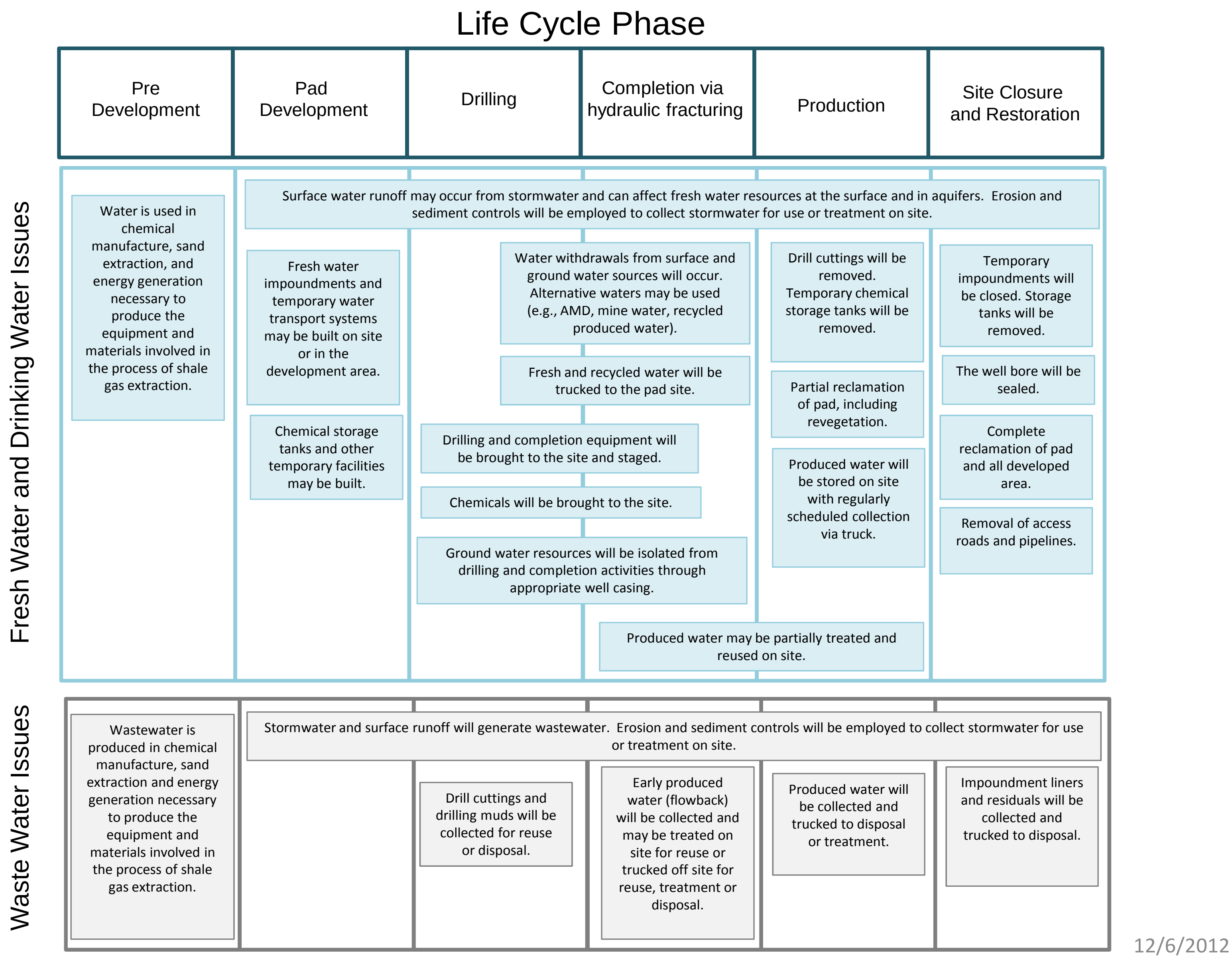

Figure 4-1. Water and wastewater issues across the life cycle of pad and well development for unconventional shale gas development.

A. Siting requirements: setbacks and restrictions

As discussed in previous and subsequent chapters, site selection for well pads and wells is an extremely important aspect of MSGD. The first step to preventing negative environmental impacts is to make careful site selections and require adequate setbacks to reduce impacts to critical water resources. While water has a number of different values that require consideration (some of these are discussed in Chapter 6), we primarily address water used for humans in this section.

In Allegany County (2011 estimated population of 74,692), 83% of the population uses surface water (community- provided) while 17% of the population uses groundwater (individual wells). In Garrett County (2011 estimated population of 30,051) 90% of the population uses ground water (predominantly individual wells: 70%), while 10% of the population uses community-provided surface water. In Allegany County, two large drinking water systems (City of Cumberland and the City of Frostburg), one medium system (Midland-Lonaconing), and one very small system (Rawlings Heights) treat their surface water. Three medium systems (Eastern Region Allegany, Lavale Sanitary Commission, Western Region Allegany) and two small systems (Bel-Air Pinto and Southern Region Allegany) purchase surface water from another provider. Six very small systems (Barrelville, Green Ridge, Midlothian, Reckley Spring, and Rocky Gap) use groundwater, and one other system (Mount Savage) uses groundwater under the influence of surface water. An additional three non-transient non-community systems and 36 transient non-community water systems are predominantly on groundwater (only Rocky Gap State Park uses surface water). For the City of Cumberland, the source water is the Lake Koon and Gordon reservoirs in Pennsylvania, part of the Evitts Creek watershed. The City of Frostburg receives its water from the Piney Dam Reservoir in Garrett County, MD, as well as from two deep wells in the Pocono aquifer and a series of springhouses. These sources are mixed prior to treatment. The Midland-Lonaconing system uses several reservoirs (Midland Gilmore, Charlestown, Koontz) that are part of the Georges Creek watershed (Potomac River watershed) and all fed by headwater streams. This surface water is supplemented by several groundwater wells that either pump into the reservoir or the plant.

All public drinking water systems in Garrett County are small: two systems (Friendsville and Oakland) are on surface water and three systems (McHenry, Mountain Lake Park, Grantsville) are on groundwater. Two very small systems (Bloomington and Kitzmiller) are on surface water, while the balance (Backbone Mountain, Crellin, Gorman, Meadow Mountain, Meadow Park, Savage Mountain, Accident, Deer Park, and White Oak) are on groundwater. An additional 11 non-transient non-community systems and 75 transient non-community water systems are all on groundwater.

Sufficient water is impounded for the surface water plants in the region, but historical water supply problems suggest vulnerability on quantity should additional withdrawals take place from the reservoirs or the tributaries that feed them at certain times of the year. Further, source water assessment documents for Evitts Creek watershed indicate concerns with turbidity increases associated with rainfall events that would likely be exacerbated if development did not include adequate sedimentation controls (PADEP 2003). Similarly, Piney Dam Reservoir exhibits elevated nutrients and sodium levels, likely due to agricultural runoff and development, increasing the risk of harmful algal blooms that challenge drinking water treatment systems

(Castro et al. 2001). As indicated by the assessment above, significant numbers of western Maryland residents rely on groundwater for their domestic water use.

Particularly in Garrett County, private well supply dependence (see Figure 4-2) suggests a strong need for setbacks and siting criteria that can effectively reduce the risks to these resources posed by surface spills (or incorrect drilling and cementing techniques in well development). Therefore, public and private water supply well identification should be part of the initial permit application process. Setbacks from existing water wells should be incorporated into siting requirements. Setbacks should be selected based on the source (groundwater wells vs. surface water intakes) and based on the area of influence for a well (the region of the aquifer affected by the pumping) and the mixing zone for a surface water system. Large public system wells have more impact on the aquifer, and thus, surface disturbance or accidental spills over a larger surface area could affect public system wells, necessitating larger setbacks. For surface waters, an upstream spill will have the largest impact if it occurs close to the intake where natural dilution capacity will be the smallest; thus surface water intake setbacks provide a buffer, usually called a mixing zone, for dilution of a spilled material upstream of an intake.

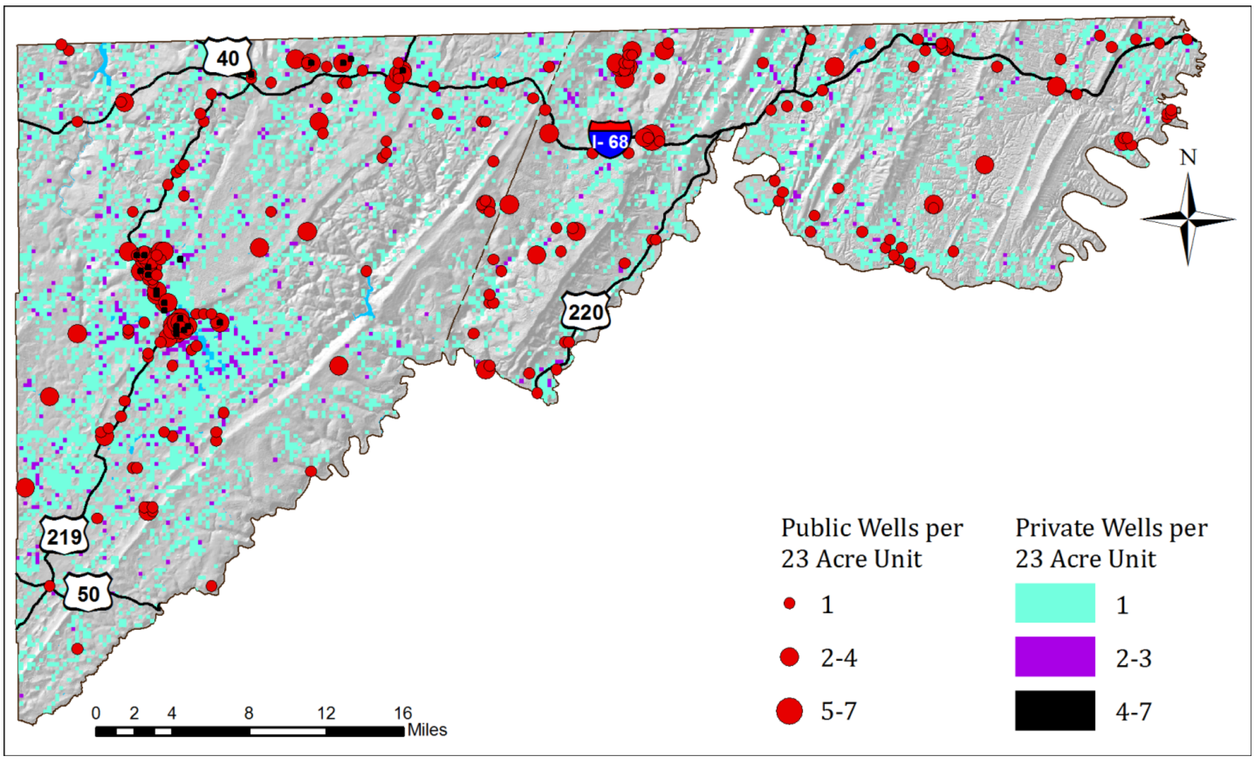

Figure 4-2. Map of density of public and private wells in western Maryland. Note: 23 acre unit is equivalent to 10^6 sq. ft.

Setbacks for public and private wells in current regulations are variable, although it has been recommended that both Pennsylvania and New York establish 500 ft. setbacks for private wells. Such setbacks could be waived with owner's permission. West Virginia and Pennsylvania presently enforce 1,000 ft. setbacks to surface intakes and groundwater wells used for public water supply systems, but it has been recommended that New York impose a 2,000 ft. setback for public system intakes (NYSDEC 2011). Therefore, based on our review of what is being done in other states, we recommend that a best practice for Maryland would be to establish a 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 wells, respectively, and a setback of 2000 ft. upstream from public surface water supply intakes.

Both Pennsylvania and West Virginia have presumption of contamination rules for drinking water wells that contain contaminants after drilling has taken place. Currently, the zone of presumptive liability is 1,000 feet. The Pennsylvania Governor's Marcellus Shale Advisory Commission recommended increasing the liability zone to 2,500 feet from public water supply wells (Marcellus Shale Advisory Commission 2011). The Center for Rural Pennsylvania completed a report based on analysis of water quality in private water wells in proximity to Marcellus gas wells, which recommended increasing the zone of liability to 3,000 feet from private water wells (Boyer et al. 2011). In 2012, the Maryland legislature established a rebuttable presumption that drilling or fracking activities were the cause of drinking water contamination if the contamination occurred within 2500 feet of the vertical borehole and within 365 days[3]. Pre-drilling sampling is not required, and refusal of such sampling vacates the landowner's right to compensatory damages. We support this regulatory structure and recommend that all water quality data collected through pre-drilling testing be provided to the appropriate Maryland agency as well as to landowners to increase the information available related to groundwater resources regionally. Pre-development notification should be made to public and private drinking water well owners. Further, we recommend requiring post-development assessment of impacts to drinking water wells. These issues are discussed further in section B below.

Due to the heavy reliance on impounded surface water from headwater streams in small, mostly forested watersheds as a drinking water source for the majority of Allegany County residents, water withdrawal plans and drill pad siting plans should be assessed within the context of watershed protection plans previously developed by the drinking water providers. Source water assessment and protection plans typically include source water delineation maps, transportation corridors, and existing potential sources of water quality impairment information that can assist permitting and siting decisions. Any drinking water provider that does not have a watershed protection plan should be required to develop one in advance of any approved development within its source watershed. To avoid contamination of all streams and rivers, no drilling should be conducted on floodplains, nor should materials or equipment be staged on floodplains. Setbacks should be extended for on-site staging and storage of hazardous materials and for eventual collection tanks for produced water. Setbacks from streams and wetlands are also recommended to reduce the potential for surface spills affecting source waters; consistent with recommendations in Chapter 6, a 300 ft. buffer from all streams, wetlands, and springs should be enforced to protect surface water quality. As noted above, Maryland should enforce a 2,000 ft. setback from drinking water intakes for surface water plants to reduce direct contamination in the event of spills on site. Watershed protection plans, specific for each water provider, may in some cases recommend greater setbacks due to unique conditions within source watersheds. In particular, both large community systems in western Maryland (City of Cumberland and City of Frostburg) receive most of their source water from Pennsylvania watersheds, so an assessment of current oil and gas water withdrawals and permitted development within the upstream basins in

[3] Md. Env. Code § 14-110.1 (H.B. 1123).

Pennsylvania is clearly warranted. We recommend flexibility in the setback statute to enable requirement of larger setbacks when warranted by analysis of watershed protection plans from drinking water systems.

B. Monitoring of water resources prior to, during, and following development

As discussed in section A above, routine pre-drilling assessment of groundwater quality should be required in Maryland. Pre-drilling public notification should also be part of the permit process, thus allowing well owners outside the pre-drilling survey area to pursue their own water quality sampling, if desired. In Pennsylvania, citizens have to 'opt-in' for notification of drilling in their area. Maryland should proactively publicize planned activities during the pre-drilling phase of MSGD. The identification of all potentially affected groundwater wells and pre-drilling testing of these wells is a best management practice that should be required in Maryland. Pre-drilling testing should be required to be conducted by the operator and the results provided to the Maryland Department of the Environment 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 groundwater would be to require post-drilling 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. As noted above, in Pennsylvania this is 1,000 ft., but longer distances are likely relevant for the more intensive activities associated with horizontal drilling and completion and have been recommended by several Pennsylvania studies (Boyer et al. 2011, Marcellus Shale Advisory Commission 2011).

More extensive groundwater testing (e.g., up to ½ mile from the planned activity) would likely produce a better baseline of water quality in the region. Since Maryland does not have extensive information on groundwater in the western part of the state, extensive pre-drilling testing could provide important information to MDE to be used in addressing potential impacts of development on groundwater resources. Testing should include, at a minimum, the well yield and the following water quality parameters: conductivity, total suspended solids or turbidity, total dissolved solids (TDS), chloride, bromide, sulfate, barium, strontium, naturally occurring radioactive materials (NORM), chemical oxygen demand (COD), and BTEX (benzene, toluene, ethylbenzene, and xylene). Currently, MGS tests for a wide variety of natural and anthropogenic compounds in well samples (see Table 4-1). We recommend using this same suite of analyses for pre- and post-drilling sampling to provide the most comprehensive information on conditions in the subsurface and add to the repository of knowledge in Maryland about groundwater resources.

We support the proposal that water samples be collected by qualified professionals and analyzed utilizing an approved analytical laboratory (i.e., one approved by the Environmental Laboratory Accreditation Program, ELAP), including the use of proper sampling and laboratory protocols in addition to the use of proper sample containers, preservation methods, holding times, chain of custody, analytical methods, and laboratory quality assurance/quality control (QA/QC) procedures (NYSDEC 2011). As noted above, all data should be shared with MDE and MGS. In addition, Maryland should require full disclosure of hydraulic fracturing chemicals well in advance of their use (see Section I), thus enabling pre-development and post-development groundwater monitoring efforts to include some of these substances. Post-completion well testing should include the same wells tested in the pre-drilling phase of development.

Table 4-1.
Recommended water-quality constituents to be analyzed in groundwater in pre- and post-drilling assessment of Marcellus shale area.

MAJOR IONS AND INDICATORS			
Calcium	Sulfate	Fluoride	Dissolved oxygen
Magnesium	Chloride	Bromide	Total dissolved solids
Sodium	Alkalinity	Silica	(residue at 180° C.)
Potassium	Specific conductance	Color	Total organic carbon
Nitrate plus nitrite	Methane	pH	
Nitrite			
Ammonia			
TRACE ELEMENTS			
Aluminum	Cadmium	Iron	Strontium
Antimony	Chromium	Manganese	Thallium
Arsenic	Cobalt	Molybdenum	Uranium
Barium	Copper	Nickel	Vanadium
Beryllium	Lead	Selenium	Zinc
Boron	Lithium	Silver	

HYDROCARBONS AND METHANE ISOTOPES	**RADIONUCLIDES**
Methane	Gross alpha-particle activity
Ethane	Gross beta-particle activity
Ethene	(both analyzed within three days of sample collection and again at 30 days after sample collection)
Propane	
$^{2}H\text{-}CH_4$ (if sufficient methane available)	
$^{13}C\text{-}CH_4$ (if sufficient methane available)	Radon-222

New developments in sensing technology have enabled improved monitoring at a variety of locations with the potential to be affected by MSGD in Maryland. Drinking water providers in Pennsylvania and West Virginia have installed a network of source water monitoring equipment for early detection of changes in conductivity (that can indicate salt levels are rising). The River Alert Information Network (RAIN)[4] enables early detection of changes in source water conditions that affect drinking water treatment and finished water quality for consumers. RAIN is a collaborative effort among drinking water plants, PADEP, West Virginia Department of Environmental Protection (WVDEP), and USEPA, with joint funding for the sensors, deployment, and maintenance. RAIN should be extended into the Marcellus development area in western Maryland, with funding provided to drinking water utilities to install monitors near their intakes. Drinking water utilities have the technical expertise to operate and maintain these sensors and can provide early notification of any significant changes in water quality. Drinking water treatment plants operating in western Maryland should also increase their source water monitoring and specifically include bromide in their routine analyses. In other shale states, universities and watershed groups have also been involved in enhanced water sampling programs to provide baseline information on water quality and to alert the public when changed indicate

[4] Information on RAIN is available at www.3rain.org.

problems that might be associated with shale gas development activities. These organizations can be involved (and are already involved to some degree) within Maryland as well. Routine sampling and the installation of real time sensors can provide useful data for understanding assessing any impacts of MSGD on water resources in the state). MDE should consider leveraging existing monitoring networks run by universities, watershed groups and other organizations as a way of capitalizing on existing datasets for baseline characterization.

C. Water pollution, stormwater management, and erosion and sediment control across the life cycle

Development of shale gas begins as many other types of construction projects do with clearing and leveling of land for the creation of a well pad; additional cleared acreage would likely be needed for roads, impoundments, pipelines, and utility corridors (see Chapter 1). One of the challenges for water associated with land clearing is stormwater runoff from drilling pads, including erosion and sedimentation and wash-off of any chemicals that have been spilled onto the pad during the various phases of an operation. Runoff of this type has the potential to affect downstream human water use as well as aquatic habitat, biodiversity, and wildlife (see Chapter 6). For this reason, implementation of effective BMPs for stormwater pollution and erosion and sediment controls will be critical in managing potential water quality impacts of MSGD.

Surface water pollution in the U.S. is primarily addressed by the Federal Clean Water Act. The Clean Water Act (CWA) prohibits the discharge of pollutants by point sources into waters of the U.S., except in compliance with certain provisions of the Act, specifically section 402, 33 U.S.C. 1311(a). Section 402 establishes the National Pollutant Discharge Elimination System (NPDES) under which USEPA, or an authorized state agency, may issue permits that allow the discharge of pollutants into U.S. waters. In developing effluent limitations for an NPDES permit, limits based on available technology (i.e., technology-based effluent limits) and on the water quality standards of the receiving water (i.e., water quality-based effluent limits) must be considered. Technology-based effluent limits for direct discharges from oil and gas extraction facilities into surface waters are found in 40 CFR Part 35, Subpart C. The effluent guidelines thus establish best practicable control technology currently available for on-shore oil and gas extraction facilities are as follows: "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 waters, drilling muds, drill cuttings, and produced sand)." The importance of this "no discharge" limit is that oil and gas facilities are not required to apply for an NPDES permit and that states can use their own authority to ensure that the "no discharge" requirement in the effluent guidelines is properly applied and that operator compliance is demonstrated[5]. The "no discharge" limit has obvious important implications for how the wastes (e.g., flowback, produced water, drilling muds, etc.) generated by onshore oil and gas facilities must be handled under federal law (see Sections G and H below). In addition to regulating such direct discharges, USEPA's regulations also address (1) indirect releases of wastewaters into U.S. waters such as by publicly owned treatment works (POTWs) that have received oil and gas

[5] Attachment to memorandum from James Hanlon, Director of EPA's Office of Wastewater Management, to the USEPA Regions titled "Natural Gas Drilling in the Marcellus Shale under the NPDES Program" (March 16, 2011).

wastes; or (2) direct discharges from centralized treatment facilities that are subject to their own technology-based and water quality-based effluent guidelines.

The CWA also gives USEPA (and authorized state programs) the authority to regulate stormwater pollution under a separate NPDES permitting program. Impervious surfaces, such as buildings, homes, roads, sidewalks, and parking lots, can significantly alter the natural hydrology of the land by increasing the volume, velocity, and temperature of runoff and by decreasing its infiltration capacity. Increasing the volume and velocity of stormwater runoff can cause stream bank erosion, flooding, and degradation of stream aquatic habitat. As stormwater runoff is produced, it can pick up trash, debris, and various pollutants such as sediment, oil and grease, pesticides and other toxics. Changes in ambient water temperature, sediment, and pollutants in stormwater runoff can be detrimental to aquatic life, wildlife, habitat, and human health. Soil exposed by construction activities is especially vulnerable to erosion. Excess sediment can increase the turbidity of receiving surface waters, reduce the amount of sunlight reaching aquatic plants, clog fish gills, and smother aquatic habitat and spawning areas. Therefore, the primary stormwater pollutant of concern from construction is usually sediment, and practices must be implemented to effectively control runoff and associated stormwater pollution. USEPA regulations require operators disturbing one acre or more of land[6] (including smaller individual areas that are part of larger developments) to apply for coverage under a NPDES construction general permit for stormwater discharge and develop and implement a Stormwater Pollution Prevention Program (SWPPP). An SWPPP is a site-specific, written document that: (1) identifies potential sources of stormwater pollution at the construction site; (2) describes practices (BMPs) that will be employed to reduce pollutants in stormwater discharges from the site; and (3) identifies procedures that an operator will implement to comply with the terms and conditions of a construction general permit. Pollution reduction is most often achieved by controlling the volume of stormwater runoff (e.g., taking steps to allow stormwater to infiltrate into the soil).

As in point source permitting, Maryland is also authorized to issue coverage under the NPDES construction general permit for stormwater discharges and has issued its own guidance documents and technical design manuals to aid in development of SWPPPs and implementation of BMPs for stormwater, erosion and sediment controls.[7] While Maryland appears to have a robust program for controlling stormwater pollution, we believe there is a significant regulatory impediment to effective implementation of BMPs to address stormwater pollution impacts associated with MSGD in the state and elsewhere. First of all, as amended by the Energy Policy Act of 2005, the CWA (section 402(1)(2) and 502(24)) specifically exempts oil and gas operations from most industrial stormwater permitting requirements by USEPA or by those states with approved NPDES programs (such as Maryland)[8,9]. Specifically, the section of the act reads as follows: “All field activities or operations associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling

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[6] Some states grant variances for activities that disturb less than five acres of land.

[7] Maryland Stormwater Design Manual, Volumes I and II (effective October 2000, revised May 2009);http://www.mde.state.md.us/programs/Water/StormwaterManagementProgram/MarylandStormwaterDesignManual/Pages/programs/waterprograms/sedimentandstormwater/stormwater_design/index.aspx

[8] 40 CFR § 122.26 Storm water discharges.

[9] Ibid., 5

equipment, whether or not such field activities or operations may be considered to be construction activities, except in accordance with paragraph (c)(1)(iii) of this section. Discharges of sediment from construction activities associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities are not subject to the provisions of paragraph (c)(1)(iii)(C) of this section."[10] While exempted from NPDES industrial stormwater permitting, it is noted in the same statutes that the USEPA "encourages operators of oil and gas field activities or operations to implement and maintain best management practices (BMPs) to minimize discharges of pollutants, including sediment, in storm water both during and after construction activities to help ensure protection of surface water quality during storm events. Appropriate controls would be those suitable to the site conditions and consistent with generally accepted engineering design criteria and manufacturer specifications. Selection of BMPs could also be affected by seasonal or climate conditions." [11]

The importance of this exemption is that, unlike an entire suite of different types of industrial activities and operations[12] that are *not* exempted from industrial stormwater permitting under the CWA, USEPA lacks the authority to regulate stormwater pollution from oil and gas activities in the same way that it would do so for these other industrial activities. In Maryland, which is authorized by USEPA to do NPDES industrial stormwater permitting, oil and gas extraction sites are not statutorily exempted from the sediment and erosion control program. However, oil and gas extraction sites are not considered "hotspots" for stormwater pollution impacts, although they may meet the definition[13] of "hotspots". Unlike most other industrial operations with equivalent (or perhaps even lower) risks of impacting surface water quality that are *required* to obtain an NPDES industrial permit and implement stormwater pollution prevention plans that address pollution both during and after construction, oil and gas operators are merely *encouraged* to implement BMPs to control stormwater pollution and can be covered under the general construction permit[14]. USEPA and the approved state NPDES programs such as those in Maryland may be hampered in their efforts to control stormwater pollution from MSGD due to this exemption in federal law.

Other than consistency with the federal exemption, there is no compelling reason for Maryland to exempt oil and gas extraction activities from its industrial stormwater permitting requirements. Designation as a hotspot has practical implications for management of stormwater. Typically, at

[10] 40 CFR § 122.26(a)(2)(ii)

[11] Ibid.

[12] Including vehicle salvage yards and recycling facilities, vehicle service and maintenance facilities, vehicle and equipment cleaning facilities, fleet storage areas, industrial sites, marinas, outdoor liquid container storage facilities, and outdoor loading/unloading facilities; see Maryland Stormwater Design Manual, Volumes I and II (effective October 2000, revised May 2009); Appendix D.6 Industrial Stormwater Permit Requirements; http://www.mde.state.md.us/programs/Water/StormwaterManagementProgram/MarylandStormwaterDesignManual/Pages/programs/waterprograms/sedimentandstormwater/stormwater_design/index.aspx

[13] A stormwater hotspot is defined as a land use or activity that generates higher concentrations of hydrocarbons, trace metals or toxicants than are found in typical stormwater runoff, based on monitoring studies . See Maryland Stormwater Design Manual, Volumes I and II (effective October 2000, revised May 2009); Chapter 2.8 Designation of Stormwater Hotspots; http://www.mde.state.md.us/programs/Water/StormwaterManagementProgram/MarylandStormwaterDesignManual/Pages/programs/waterprograms/sedimentandstormwater/stormwater_design/index.aspx

[14] Operations that result in disturbances of less than five acres of total land area are also exempted under 40 CFR § 122.26(b)(14)(x).

construction sites where the primary concern is erosion and downstream sedimentation, SWPPPs tend to emphasize BMPs that promote infiltration into the ground as a primary means of reducing stormwater discharges and thus associated erosion and sedimentation problems. Performance standards developed in Maryland through largely urban stormwater control emphasize site designs that maximize pervious areas for stormwater treatment (standard no. 1) and promote infiltration through the use of structural and non-structural methods (standard no. 2)[15]. However, for hotspots, where untreated stormwater runoff cannot be allowed to infiltrate into the ground, Maryland applies differential requirements to prevent groundwater contamination. Since oil and gas development sites are more similar to hotspots than to urban development sites, Maryland should review its stormwater regulations to ensure oil and gas extraction operations are managed in accordance with their characteristics, rather than through a statutory exemption. The use of a generic SWPPP, such as is often developed for residential subdivisions, is not the correct approach for managing stormwater pollution from shale gas operations.

The primary goal, intent, and spirit of the CWA is found in the first sentence of the act [Section 101(a)] where it states that the legislation is meant to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters". While the *restoration* component of the CWA is largely being dealt with by the states through regulation of point and non-point discharges of water quality pollutants, the goal to *maintain* water quality in situations where impairment is not presently an issue is addressed under the federal anti-degradation policy. This regulatory policy, described in Section 303(d) of the CWA, is designed to prevent deterioration of existing levels of high or exceptional water quality in areas where such conditions exist. The federal policy requires states to develop rules and implementation procedures to protect existing uses of such waters and to prevent such waters from being degraded (unless the action responsible for the deterioration provides an important social or economic benefit). Each state's anti-degradation rules and implementation procedures must be included in the state's water quality standards (WQS). In addition, the federal rules[16] require that:

- Existing in-stream water uses and the level of water quality necessary to protect the existing uses shall be maintained and protected.
- Where the quality of the waters exceeds levels necessary to support propagation of fish, shellfish, and wildlife and recreation in and on the water, that quality shall be maintained and protected unless the State finds, after full satisfaction of the intergovernmental coordination and public participation provisions of the State's continuing planning process, that allowing lower water quality is necessary to accommodate important economic or social development in the area in which the waters are located. In allowing such degradation or lower water quality, the State shall assure water quality adequate to protect existing uses fully.
- The state shall assure that there shall be achieved the highest statutory and regulatory requirements for all new and existing point sources and all cost-effective and reasonable best management practices for non-point source control.

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[15] Maryland Stormwater Design Manual, Volumes I and II (effective October 2000, revised May 2009); Chapter 1.0 Introduction; http://www.mde.state.md.us/programs/Water/StormwaterManagementProgram/MarylandStormwaterDesignManual/Pages/programs/waterprograms/sedimentandstormwater/stormwater_design/index.aspx

[16] 40 CFR §131.12

- Where high quality waters constitute an outstanding national resource, such as waters of national and state parks and wildlife refuges and waters of exceptional recreational or ecological significance, that water quality shall be maintained and protected.

Essentially, under federal rules, each state's anti-degradation policy must be implemented under a three-tiered program:

- "Tier 1", that protects "existing uses" and provides the absolute floor of water quality for all waters of the United States [Section 131.13(a)(1)];
- "Tier 2", that includes "high quality waters" (HQW) in which water quality exceeds that necessary to protect the Section 101(a)(2) goals (fishable and swimmable). Water quality may be lowered under certain conditions, but never below the level necessary to fully protect the "fishable and swimmable" and other existing uses [Section 131.12(a)(2)]; and
- "Tier 3", that are "outstanding national resource waters" (ONRW) in which only temporary reductions in water quality are allowed [Section 131.12(a)(3)].

Maryland adopted its anti-degradation policy as part of the WQS in 1985 and revised its policy in 2001. In 2004, Maryland adopted its current Tier II implementation policy and promulgated a list of 87 Tier II (i.e., HQW) stream segments based on established criteria of biological integrity; the majority of these Tier II segments are located in western Maryland (Figure 4-3). Maryland's current Tier II policy states that "where water quality is better than the minimum requirements specified by the WQS, that water quality shall be maintained". MDE will enforce the state Tier II policy by requiring that "applicants for proposed amendments to county plans or discharge permits for discharge to Tier II waters that will result in a new, or an increased, permitted annual discharge of pollutants and a potential impact to water quality, shall evaluate alternatives to eliminate or reduce discharges or impacts". A Tier II anti-degradation review is required for permits involving individual discharges of at least 5,000 gallons per day; however, lesser proposed *point* discharges—and presumably non-point source discharges—of pollutants that could potentially contribute to significant degradation of water quality (especially of small streams) are exempted from anti-degradation review. Given this necessary trigger and the fact that point discharges from oil and gas development cannot be permitted as discussed earlier, we do not believe that MSGD would trigger a Tier II anti-degradation review in Maryland under current policy. For this reason, 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 (e.g., forest management, MSGD, etc.) conducted in Tier II watersheds meet an anti-degradation standard.[17]

Based on review of stormwater management practices in other states, we recommend 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. This practice requires careful grading during the pad construction process, so that water (i.e., mostly excess precipitation onto the pad, but also any other liquids) can flow by gravity to a single location on the pad where these liquids can be collected on a regular basis—typically using vacuum trucks. A berm around the entire pad should be designed to prevent any stormwater from being

[17] The state of Washington has a similar approach for applying anti-degradation rules to forest practices, and Oregon is considering such an approach (State of Oregon Department of Environmental Quality, 2010).

discharged from the pad, except for the entrance road that should be elevated slightly above the pad to prevent runoff by the road. The entire pad must be underlain with a heavy impervious synthetic liner (comparable to liners used by landfills). Any areas where mechanized equipment will operate should be overlain with a composite decking material to protect the liner from abrasion and prevent infiltration (Lien and Manner 2010).

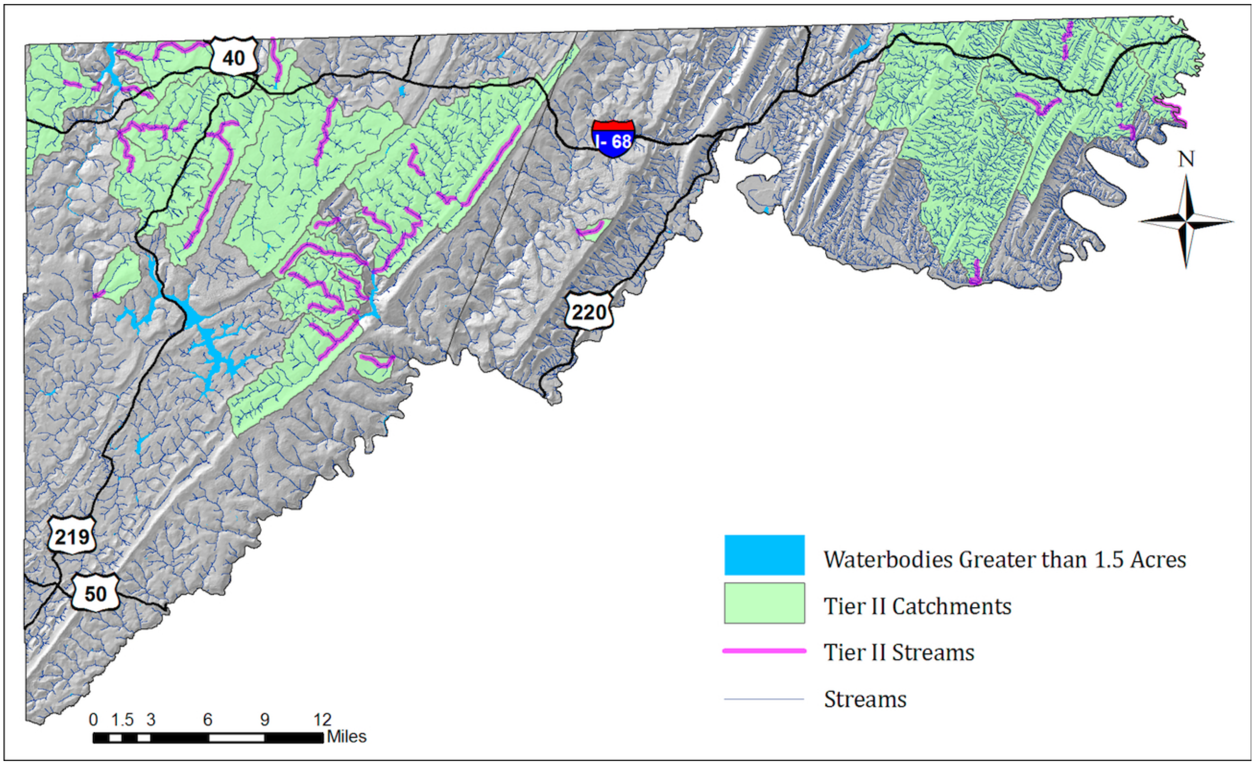

Figure 4-3. Map showing locations of Tier II (i.e., HQW) streams (and catchments associated with these streams) and waterbodies greater than 1.5 acres in western Maryland.

One of the weaknesses of this approach is that the system relies on coordination of active (vacuum trucks, water reuse) and passive (berms, liners) stormwater pollution prevention measures. In Maryland's seasonally wet climate, it's likely that well pads would overflow once active management ends. Since personnel are only expected to be on site continuously during active drilling and completion phases of development of a particular well, it is imperative to consider how these pads will function after well completion, or between different rounds of activities (wells completed at different times from the same pad). Since activities at the pad site may cycle through periods of active development and periods of production, pad reclamation to manage stormwater may have to occur multiple times. There are two options for managing runoff from drill pads between episodes of drilling: (1) the pads could be revegetated and restored to original condition any time operations cease for a defined time period (i.e., this would avoid excess runoff that was not being managed); or (2) the developed area could remain disturbed and a stormwater collection and management system could remain in place. The best solution for addressing both quality (i.e., suspended solids) and quantity (i.e., peak discharge) issues would be through 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 any passive phases. Regular periodic (annual) maintenance of the pond would also be needed to ensure that the system is functioning correctly at all times. Additional water quality treatment could be obtained through operation of a constructed wetland sited downstream of the pond outlet.

Related to stormwater management, operators would be required to develop and implement erosion and sediment control plans. These plans usually include BMPs for: (a) grading and stabilization to minimize erosion during development; (b) water conveyance plans for clear-water diversions around the development area to reduce stormwater that picks up sediment on the site; (c) erosion control that reduces the velocity of surface flows; (d) filtering and sediment trapping systems to collect sediment and prevent its discharge from the site; and (e) dewatering practices, if applicable to a site. Some plans also specify reclamation requirements, including restoration of grades and re-vegetation to prevent post-development changes in sediment loads from the site. Plans are typically certified by a registered professional engineer (PE). Each of these elements should be addressed in Maryland's regulations. Soil erosion and sediment control plans should also be required for the development of new roads to sites. Stream crossings and development through wetland areas should be avoided (see Chapter 6 also). In addition, as recommended for New York and Pennsylvania, the design of all stormwater control structures to address erosion and sedimentation should be based on a 10yr/24hr rainstorm (i.e., the rainstorm with a duration of 24 hours that occurs, on average, once every ten years), as opposed to the 2yr/24hr storm that occurs more frequently. Given the complexities in addressing how active and passive stormwater management will occur, we also recommend that the state ensure that Soil Conservation Districts, which currently review and approve sediment control plans and who are most knowledgeable for their geographic area are on-site during all major construction/deconstruction activities. Post-construction inspections of stormwater structures by MDE and the relevant Soil Conservation District personnel should occur prior to well drilling and completion.

On January 27, 2012, Maryland enacted new regulations for soil erosion and sediment control (MDE 2011). As part of this new regulation, each county is required to draft erosion and sediment control ordinances by January 2013. A model ordinance was published by Maryland in February 2012 (MDE 2012). The model ordinance includes an exemption for clearing or grading activities that disturb less than 5,000 square ft. of land area (~ 0.1 acre), which is a fairly typical exemption that is unlikely to affect shale gas pads (typically on the order of 4-6 acres in size). In the Maryland model ordinance, Erosion and Sediment Control (ESC) plan review is required prior to permit approval. This is ideal and should be retained (some state regulations have exemptions that pertain specifically to oil and gas development[18]). Garrett and Allegany County should follow the Model Ordinance proposed by MDE, but should also require consideration in ESC plans of the potential effects of multiple clearings in relatively close proximity. Exemptions for small sites should not be enacted. Maryland should also evaluate potential issues associated

[18] For example, it is our understanding of Pennsylvania's regulations that gas exploration and extraction facilities that result in disturbance of fewer than five acres are not required to obtain an "Erosion and Sediment Control Permit". For such facilities (e.g., well pads), a "Permit Application for Drilling or Altering a Well" (5500-PMOG0001) is sufficient. An Erosion and Sediment Control Plan must still be developed, but the plan is not subject to regulatory review and approval before construction. This is in contrast to most other construction activities, which are subject to erosion and sediment control requirements at one acre or greater under the Pennsylvania Chapter 102 requirements and NPDES requirements.

with stormwater, sedimentation and erosion within the context of multiple simultaneous MSGD sites and use its discretionary authority to require individual stormwater permits when warranted. ESC plans will also be critical in managing potential impacts on downstream water users. Maryland should ensure that public water supplies downstream of permitted MSGD activities should be notified prior to such activities.

With respect to specific BMPs, operators should be strongly encouraged to consult Maryland's Stormwater Design Manual and an industry document entitled "Guidance Document, Reasonable and Prudent Practices for Stabilization (RAPPS) at Oil and Natural Gas Exploration and Production Sites" published by API. The latter report describes a host of specific operating practices and control measures that have been used and tested by oil and natural gas operators to effectively control erosion and sedimentation from stormwater runoff resulting from land clearing, grading, and excavation operations at exploration and production sites under various conditions of location, climate and slope.

D. Water withdrawals

At the scale of a single well or multiple wells on a single pad, 2-6 million gallons of water must be acquired to facilitate the drilling and completion of each well. The amount varies based primarily as a function of the length of the drilled lateral. To support MSGD, water can be extracted from surface or groundwater sources (including non-potable sources, see Section G), or even purchased from existing treatment plants if excess capacity exists. While 2-6 million gallons is a large volume of water, it is important to keep it in context relative to other withdrawals and supplies of water in the state. It was estimated by USGS that in the year 2000, Allegany and Garrett County withdrew on average 48.9 and 9.6 million gallons per day (MGD), respectively, from all surface water and groundwater sources. Over the course of an entire year, this works out to a combined volume of about 21.4 billion gallons of water. Thus, the combined annual withdrawals by these two counties alone would be equivalent to the amount of water required to develop about 3,500 Marcellus shale gas wells in the state.

There are very long gage records available from USGS for most of the major rivers that could be used to support MSGD in western Maryland. We computed the mean annual discharge in western Maryland's three largest headwater rivers (North Branch Potomac River near Steyer, Youghiogheny River at Friendsville, and Savage River below Savage River Dam) based on these records as part of a preliminary analysis of supply and obtained values of 112, 413, and 110 MGD, respectively. The combined long-term average discharge in these three rivers is 635 MGD—producing a volume of water on an average day that is more than 100 times larger than the water requirement to develop a single Marcellus shale gas well. However, it must be noted that the average discharge of water in these rivers varies dramatically throughout the year: in the Youghiogheny, for example, the long-term mean daily discharge in March (while normally swelled by spring snowmelt) is 769 MGD based on 71 years of data (1941-2011), although in September the long-term mean discharge is only about 22% as great (172 MGD). During low flow periods, as in drought years, flows in all of these rivers can become critical low. For example, in the Youghiogheny, the annual seven-day minimum flow was 18.7 MGD in September of 1972—illustrating that it is unlikely that flow conditions in even these major rivers can support withdrawals for MSGD at all times under all conditions. On the other hand, under average conditions and particularly at the higher discharges normally reached during the spring of the year, the data suggest that there may be adequate supplies provided by western Maryland's major rivers as source water for MSGD.

With respect to groundwater sources, in Chapter 1 we summarized the available information on western Maryland's principal aquifers from the perspective of identification of aquifers and flowpaths as part of the drilling and hazard assessment processes. Much of that information is clearly relevant to identifying sources of groundwater that could be used for HVHF. On the Appalachian Plateau in Garrett County and western Allegany County, water yields of wells completed in Pennsylvanian age sandstone formations (the principal aquifers) reportedly range from 20 to 430 gallons per minute. In the Valley & Ridge west of the Great Valley, Ordovician to Devonian age sandstones are considered the principal aquifers, but wells completed in these formations commonly yield less than 120 gallons per minute; wells in limestone formations of late Silurian through early Devonian age may locally yield as much as 100 gallons per minute where these rocks are fractured (Trapp, Jr. and Horn 1997). These individual well yields (0.03 – 0.6 MGD) are certainly high enough to suggest that western Maryland's groundwater resource could potentially be exploited to support HVHF, but research would be needed to assess whether such development would likely cause the safe yield of these aquifers to be exceeded. We can envision that groundwater could play a role in supplying hydraulic fracturing operations during dry summer periods when water levels in major rivers and reservoirs are too low to permit surface withdrawals, or cases where a particular well pad (1) is located an excessive distance from a permitted surface water supply location; or (2) is not efficiently served by public roads that enable trucking of water. A centralized water well field (with suitable impoundment) could also potentially be used to supply (via buried pipeline) a group of multi-well pads that were part of a clustered development (see Chapter 1), with the caveat that the water wells would need to be sited so as to observe recommended setbacks. In the four eastern states (with similar hydrogeologic settings) that we reviewed, we found no evidence of extensive groundwater resource development to support MSGD[19]—presumably due to limited supplies, low well yields, and high costs (compared to the surface water alternative). Use of groundwater (in some cases drawn from saline aquifers) has supported shale gas development in some western states and western Canada (King 2012), but the far greater supply of surface water at lower cost suggests that it is highly unlikely that MSGD in Maryland would be primarily supported by available groundwater resources.

In Maryland, both surface and groundwater withdrawals are regulated by MDE.[20] Permit approval requires that the applicant provide satisfactory proof that the proposed withdrawal of water is reasonable and the impacts on the water resource and other users are acceptable. Further, the proposed use must be consistent with local planning and zoning requirements and the county water and sewer plan. Additional permitting documentation is required for requests for withdrawals in excess of 10,000 gallons per day, and public notification may be required.

[19] Recent data provided by SRBC to MDE indicates that Marcellus operators in Pennsylvania have obtained permits to supply 4% of their total water needs from groundwater sources computed by averaging over the entire basin (John Grace, MDE, personal communication, February 15, 2013).

[20] COMAR 26.17.06 and COMAR 26-17.07 Details are available at: http://www.mde.maryland.gov/programs/Water/Water_Supply/Documents/www.mde.state.md.us/assets/document/permit/2008PermitGuide/WMA/3.15.pdf

Determining that a proposed withdrawal of water is "reasonable" can be done in several ways. In Maryland, the "Criteria for Approval of Water Appropriation or Use Permits"[21], provides narrative regarding reasonableness, including a consideration of: (a) the purpose of the use; (b) the suitability of the use to the watercourse, lake or aquifer; (c) the extent and the amount of harm it may cause; (d) the practicality of avoiding the harm by adjusting the proposed use or method of use of the applicant or another permittee; (e) the practicality of adjusting the quantity of water used by each permittee; (f) aggregate changes and cumulative impact that this and future appropriations in an area may have on the waters of the state; (g) the contribution that the proposed appropriation may make to future degradation of the waters of the state; and (h) whether the proposed appropriation or use is located within a water management strategy area.

For surface water sources, approved withdrawals are "conditioned on the maintenance, by the permittee, of a required minimum flow past the point of appropriation to protect other users of the water and to protect flora and fauna within the watercourse.[22]" The most common required minimum flow is typically set at the lowest 7 day average in the past 10 years (Q7-10). The Q7-10 is specific to each source water and can be difficult to determine for streams without gages. Within Maryland, the required minimum flow is not always the Q7-10. In other states, withdrawals are often allowed up to a specific restricted flow point, for example, when the flow is less than 20% of the average daily flow. For gaged streams, average daily flow is easily determined; however, for ungaged streams, a reference gage approach using USGS regression tools is required. Significant uncertainty is often observed in such predictions (Murphy et al. 2012, Razavi and Coulibaly 2012, Shu and Ouarda 2012). A comparison of the use of different methods for flow prediction using Maryland-specific historical gage data will provide a clear assessment of the most appropriate method for flow prediction in ungaged streams in the state. We are confident that there are adequate long-term and site-specific data for a sufficient number of gaged watersheds to support a rigorous analysis of stream discharges in western Maryland watersheds to inform an analysis of minimum required flow levels for streams that might support MSGD water withdrawals in the region. While we have not done such a quantitative analysis as part of our review of best practices, 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 will 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.

Determining that the "impacts on the water resource and other users are acceptable" can be even more challenging than determining minimum required flows for streams. Multiple withdrawals within a basin can have a cumulative effect that must be considered in overall basin-level analysis. One method is to require the permitee to assess the cumulative net withdrawals up-gradient of the proposed new withdrawal, and to consider cumulative impacts in the permit review process as is commonly done by basin commissions (SRBC 2012). Extensive review and analysis of watersheds in Pennsylvania has been undertaken to review and update requirements

[21] COMAR 26.17.06.05. http://www.dsd.state.md.us/comar/getfile.aspx?file=26.17.06.05.htm
[22] COMAR 26.17.06.05

related to water withdrawals as shale gas drilling has expanded throughout the Susquehanna and Ohio River basins. Several critical reviews have been completed that should be considered as Maryland decides how to update water withdrawal permitting processes to consider the temporally and spatially distributed withdrawals typical of this industry. For example, the TNC Ecosystem Flows Study (TNC 2010) was a collaboration between The Nature Conservancy (TNC), the Susquehanna River Basin Commission (SRBC) and the United States Army Corps of Engineers (USACE). This study focused specifically on the Susquehanna River and its tributaries; however, the approach and general conclusions provide important information for MDE in assessing ecosystem considerations for streamflow and the role of this component in water withdrawal permitting for shale gas development.

Recently, as part of proposed changes to the Low Flow Protection Policy of SRBC, MDE expressed concerns regarding the use of a fixed 'de minimus' threshold for headwater watersheds and highly sensitive watersheds since this 'de minimus' characterization is not used in Maryland statute (Kasraei 2012). As MDE notes in their response to SRBC, "it may not be feasible to appropriately quantify the flow regimes of certain ungaged smaller systems due to lack of relevant data" and other site specific conditions. As discussed above, the difficulty in assessing the impacts of water withdrawals with insufficient gaging data is well known (Murphy et al. 2012, Razavi and Coulibaly 2012, Shu and Ouarda 2012) and we strongly recommend that water withdrawals for MSGD be encouraged from larger rivers (and perhaps existing reservoirs). MSGD should totally avoid small headwater streams and watersheds out of concern for dewatering of these sensitive systems. Specific rather than generic minimum flow values should be established for these creek and stream systems, and seasonal water conditions should also be evaluated in the process.

Timing of water withdrawals is also critical, with low flow conditions typically occurring seasonally. Storage and water transport from storage will be necessary to enable continued operations during the dry periods when withdrawals are likely to be limited. The size and number of any centralized water impoundments and pipelines constructed to support industry operations is often predicated on the stability of water supply. When water supplies are restricted for more of the year, gas development operations will either be restricted or larger and more impoundments will be required to enable continuous operations. Details of multiple uses for a single permitted withdrawals and of the plans to construct impoundments and pipelines are often contained within the water management plan required for shale gas development in Pennsylvania. These plans require identification of the water source at the time of drill permit application and lead to more comprehensive water sourcing plans for multi-well and multi-pad development. Multiple drilling companies within a single region may present overlapping plans with little coordination on water withdrawals. A regional multi-operator approach to water provision for shale gas operation would likely reduce the number of impoundments and withdrawal locations and enable smaller facilities, while still providing adequate and stable water supplies. Water management plans, in addition to water withdrawal permits, should be required for all drilling activities to ensure that development activities incorporate water resource planning. Coordinated multi-operational water provisioning should be planned to reduce the disturbances associated with impoundments and water withdrawals.

E. Comprehensive basin-scale water management planning

Comprehensive basin-scale water management involves consideration of all uses and all activities associated with water within a watershed, often at the hydrologic unit code (HUC) level of 1 (i.e., HUC 2). This level is typically hundreds of thousands of square miles and usually involves multiple states. HUC 2 watersheds are often managed through interstate compacts. Maryland participates in several basin commissions (e.g., SRBC) and the Interstate Commission on the Potomac River Basin (ICPRB). No basin commissions exist in the most western part of the state where shale gas is found, however. Figure 4-4 shows the extent of relevant basins in Maryland.

A portion of western Maryland within Garrett County is part of the Ohio River Basin (part of the larger Mississippi River Basin). The Ohio River Basin Commission was founded in 1981; however, the organization no longer operates, and it does not assert authority over water withdrawals within the basin. The Ohio River Valley Water Sanitation Commission (ORSANCO) is an interstate commission (established in 1948) charged with management of water *quality* in the Ohio River and its tributaries. ORSANCO does not have regulatory authority over issues of water *quantity*. The USACE Pittsburgh District has authority for the Youghiogheny Reservoir, a flood control and recreational reservoir that begins in Maryland and continues into southwestern Pennsylvania. Several groups have recommended the creation of an Ohio River Basin Commission that would manage water withdrawals to ensure water quality and protection of aquatic resources, especially during low flow conditions in the region (generally summer time) and ORSANCO is currently evaluating an expanded role that would incorporate water quantity authority. In general, the Youghiogheny River has been cleaner than the Monongahela River at the points of entry to Pennsylvania, providing important dilution of the main stem of the Monongahela River that travels north from West Virginia into Pennsylvania, terminating at its confluence with the Allegheny River to form the Ohio (at Pittsburgh, PA). Changes in the water quality within the Youghiogheny River would affect downstream water users in Pennsylvania.

A major portion of Garrett County is part of the North Branch Potomac (0207002) watershed. Allegany County is located within the South and North Branch of the Potomac (0207001 and 0207002) and the Cacapon-Town (0207003) subwatersheds. The USACE Baltimore District operates both Jennings Randolph Lake and Savage River Reservoir (both part of the North Branch of the Potomac River Basin). The ICPRB is the relevant watershed management commission for this part of the region; however, the ICPRB does not manage water withdrawal permitting within the basin. Ideally, comprehensive basin-scale planning and analysis would be used for water withdrawal permitting in western Maryland and elsewhere in the Potomac and Ohio River Basins. In the absence of interstate basin commissions with water permitting authority in this region, we recommend that MDE continue to take a comprehensive, basin-scale approach to all water withdrawals and to the assessment of water management plans submitted by any shale gas developers. MDE should also discuss the operational conditions of Youghiogheny Reservoir, Savage River Reservoir, and Jennings Randolph Lakes with USACE to evaluate these systems as potential sources of water for MSGD, particularly during high flow conditions when recreational and other uses would not be negatively impacted.

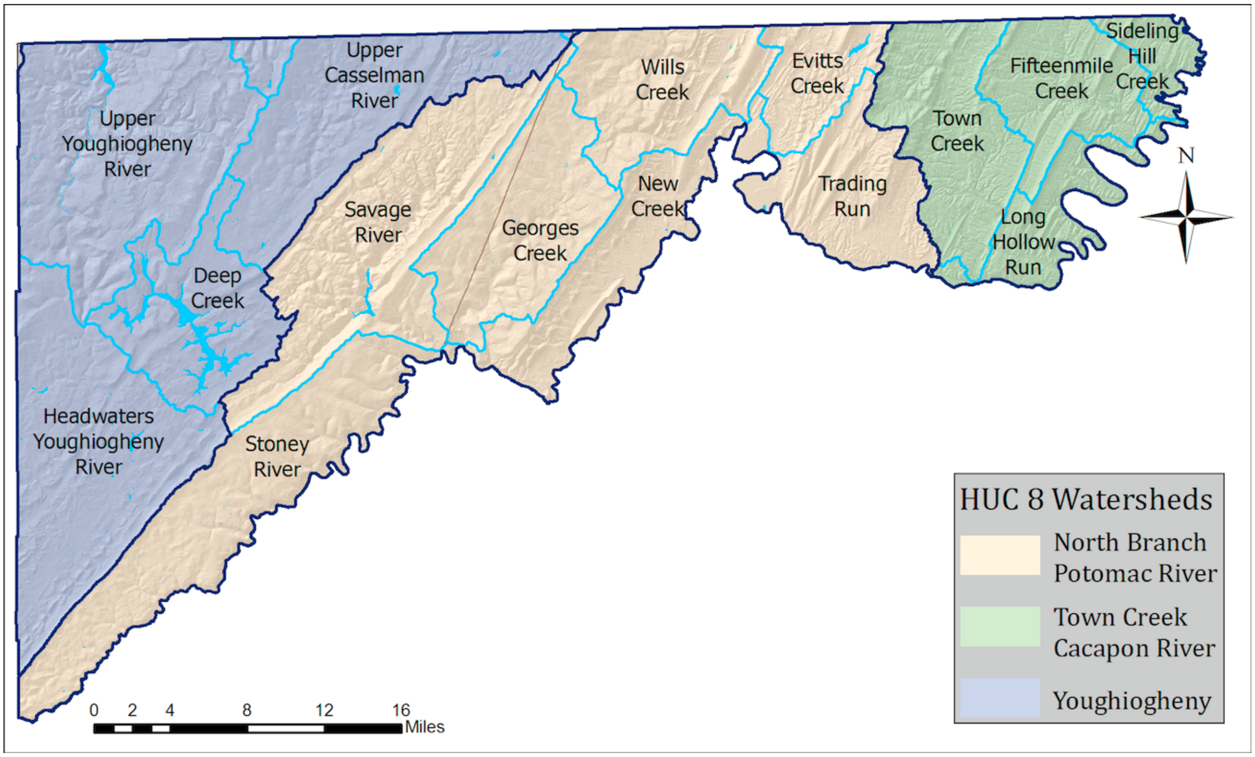

Figure 4-4. Major watersheds (HUC 8 and HUC 10) in western Maryland.

F. Water storage and delivery

Water must be staged on site at the well pad to support the hydraulic fracturing operation. During active development of the site, through drilling and the hydraulic fracturing operations, stormwater and rainfall will likely be collected for use in operations (see Section C), but this volume of water will not meet the high water needs for hydraulic fracturing. Well pad water management generally includes staging water tanks or constructing ponds to hold water, and using trucks to convey the 2-6 million gallons of water needed for the hydraulic fracturing. Alternative methods have been proposed and are currently being utilized that reduce or eliminate truck traffic and decrease the size of well pads. In the Pennsylvania state forests, freshwater is being moved from centralized storage facilities to active location(s) through the use of temporary piping. This practice significantly reduces the frequency of heavy hauling across state forest roads, minimizes the possibility of vehicular conflicts, and decreases air and dust pollution (PADCNR 2011). The piping of freshwater may involve above-ground or buried water pipeline networks, or a combination. Above-ground piping should be laid out in a manner to reduce aesthetic impacts and the potential for vandalism to the extent possible. Further, such piping should avoid interfering with existing infrastructure, including stormwater structures (e.g., culverts). Where applicable, buried piping should minimize additional earth disturbance and be co-located with natural gas pipelines, buried in the ditchline or vegetated berm, or trenched and buried beneath the running surface of an access road (PADCNR 2011). For example, in the Tiadaghton State Forest in north-central Pennsylvania, truck transport has been used to fill several constructed impoundments that provided gravity flow to an underground pipeline network that fed a cluster of well pads constructed in reasonably close proximity.

Freshwater delivered by either trucks or pipeline must also be staged near the operations. Open lined shallow impoundments (~15 MG capacity) are often constructed in Pennsylvania and used for this purpose (see Figure 1-5). The size and number of impoundments would need to be determined by the number of wells to be drilled and the number of pads within close proximity of a suitable impoundment location. Locations for these impoundments would be dictated by topography (i.e., suitable, reasonably flat locations where they can be constructed). Maryland has existing pond standards/specifications related to livestock watering, recreation, agricultural storage, and stormwater management (MDE 2000), but no specific standards exist for storage of water for oil and gas development. We recommend that freshwater impoundments be subject to the same standards regardless of water use. No impoundments constructed in Maryland should ever be used for storage of any wastewater (i.e., flowback or produced water), however. Nor should water released from temporary impoundments be discharged into any Maryland streams and rivers due to concerns for introduction of exotic species (e.g., golden algae) and impacts on water temperatures. As discussed in Section D above, coordinated planning for water needs across multiple operators and multiple well pads and development regions will reduce the number of impoundments needed to ensure reliable and sufficient water supply for this industry.

G. Alternative water sourcing

Wastewater is produced in a number of industrial activities that has potential as a source of water for hydraulic fracturing. The most frequently discussed alternate source is acid mine drainage (AMD) that is commonly discharged throughout the Marcellus shale region. Maryland Bureau of Mines has constructed and maintains 33 active and passive AMD facilities in Garrett and Allegany County with typical flows of 1 liter per second (L/s; 1 L/s = 0.023 MGD). Some of these facilities (or the mine pools from which the discharge is derived) could serve as alternate, non-potable water sources for MSGD. Among other known AMD sources is the outflow from the Hoffman Drainage Tunnel (HDT) near Clarysville, MD that typically discharges into Braddock Run (a tributary of Wills Creek) at a rate of about 7.3 MGD (recently reported range is 7–30 MGD)—making this source a candidate to be evaluated as an alternate water source[23]. As discussed by one recent report, the use of AMD-impaired water or treated wastewater could have overall positive benefits on water quality through removal of these inputs from receiving streams (Lien and Manner 2010). We must note, however, that the cold water discharge of mine water from mine workings underlying Frostburg and the Upper Georges Creek Valley into Braddock Run via HDT appears to provide sustained baseflow in the receiving stream that exceeds by more than an order of magnitude the natural flow regime. HDT discharge also allows Braddock Run to support a brook trout population[24], despite the fact that the discharge is obviously laden with ferric hydroxide—commonly known as "yellow-boy".

Nearby West Virginia and Pennsylvania have even more extensive acid mine drainage issues, with some outfalls in the tens of L/s range (Ziemkiewicz et al. 2003). Treatment costs are significant and treated water is discharged into surface waters (e.g., Hansen et al. 2010). Similarly, active coal mines and coal bed methane extraction activities generate high volumes of water during dewatering activities that are ongoing for the duration of the mining activity. These

[23] Unpublished analysis of field data by K.N. Eshleman and R.P. Morgan II for Lavale Sanitary Commission (September 4, 2002).

[24] Jason Cessna (Appalachian Laboratory), personal communication (February 11, 2013)

waters are often salty, but considerably less salty than produced water from oil and gas activities. In many states (including Pennsylvania and West Virginia) coal bed methane produced water is permitted to discharge to surface water, and discharges can be considerable (32.3 million gallons/year in the Appalachian basin; USEPA 2010). Treatment is generally necessary for use of AMD-impaired waters in hydraulic fracturing, with removal of sulfate as a critical issue to prevent formation of barium sulfate precipitates that clog the well. Both abandoned and current coal mine discharges vary significantly from site to site, so site specific characterization and treatment would be needed for use of this water. Other industrial wastewaters may also have potential to be repurposed for shale gas development; however, this would require careful consideration of the impacts of wastewater diversion on in-stream flow in receiving waters. Further, the requirements for pre-treatment of different wastewaters may make this option impractical.

Beyond water conditioning, issues of ownership and liability are a concern with use of impaired waters. As noted for Braddock Run, AMD-impaired water can even play an important ecological role as well. Drilling companies have expressed significant interest in use of AMD-impaired waters, but they do not want to be liable for cleanup of the continuing source once their short-term need for water ends. An evaluation of the potential for use of coal mine drainage for hydraulic fracturing was completed by the Rand Corporation in late 2011(Curtright and Giglio 2012). Conclusions included a need for new studies on sources of coal mine water that would be available for hydraulic fracturing, the evaluation of quantity and quality available across a region, and a collaborative approach among regulators, industry and other stakeholders to develop and analyze technical concepts and implementation mechanisms. Clearly, a best practice would be for Maryland to conduct a feasibility study on the potential use of known AMD-impaired waters in Garrett and Allegany County as source water for potential hydraulic fracturing operations. This is particularly important since as noted above, small headwater streams supply reservoirs extensively used for drinking water supply and are unlikely to have excess capacity for withdrawals. Water resources for extraction activities may be limited in areas targeted for development. As part of this study, Maryland should evaluate any regulatory limitations that would interfere with beneficial repurposing of mine water for hydraulic fracturing.

H. Chemical delivery, storage on-site, and transfers

Chemicals will need to be delivered and stored on site prior to drilling and completion operations. Some of these chemicals are hazardous and attention must be paid to their proper management. Closed storage tanks are necessary for all chemicals used on site. All tanks should be maintained in secondary containment to prevent contamination of the environment in the event of a spill. Adequate secondary containment should also be used in all areas where blending or transfer of chemicals takes place (NYSDEC 2011). Spill prevention, response and remediation plans (see Chapter 7 for details) should be developed and approved during well permitting and fully implemented when construction begins. Residual chemicals are not exempt wastes and must be managed based on their hazard classification. No blending of residual chemicals with production wastes is permitted under federal law. Operator training should be specifically required regarding the exempt vs. non-exempt wastes classification at the well pad, as this is an area of common confusion.

I. Identification of chemicals

The composition of chemicals used on site must be clearly identified for safety and to enable remediation in the event of accidental releases. While some industry participants have been proactive in disclosure of chemical use, including chemical use in drill plans and spill prevention, response and remediation plans, this openness is not universal. Many, but not all, operators provide chemical disclosure through the web site, FracFocus (www.fracfocus.org). Disclosures are permitted to include chemicals listed as proprietary if they represent a trade secret, as defined by applicable U.S. law. A best practice would be a requirement by the state of Maryland that operators provide full disclosure of chemicals used during completions. Detailed inventories including Material Data Safety Sheets (MSDS) should be required on site and on all truck manifests. 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. It must be kept in mind that MSDS may not contain information on specific chemical compounds, so it isn't clear to us whether this information is sufficient to fully protect human health in the event of a spill or other emergency, however.

Drillers report using fewer chemicals for MSGD than for other shale gas plays and the economic incentive to reduce chemical use even further is a strong motivator. To encourage advancements in "greener" (i.e., use of more benign chemicals) completions, Maryland should require completion plan alternatives during the permitting process. These recommendations are consistent with proposed practices for MSGD in New York (NYSDEC 2011).

J. Drilling and drilling wastes

Oil and gas development produces drilling wastes that must be temporarily stored on site, processed, and disposed of. Until very recently, storage was accomplished using lined open pits, but these can no longer be considered best practices. 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. As with all waste handling and processing, adequate plans for spill mitigation must be in place in the event that an accidental release occurs. Since most drilling muds contain polymer additives, cuttings generally represent a mixture of native and amended materials that should be managed in accordance with their chemical characteristics. While oil and gas production wastes have a federal statutory exemption under RCRA and are, therefore, not categorized as hazardous wastes, they should be managed as wastes and their disposal should be based on their characteristics. Drill cuttings should be separated, recycled, or properly landfilled. Due to the potential for cuttings from shale formations to contain NORM, on-site disposal should not be permitted. Landfill disposal should be allowed when NORM levels indicate no significant enrichment beyond background levels. State action levels for NORM range from 5-30 picocuries per gram (pCi/g) of total radium and levels considered to represent 'uncontaminated' materials are often set at twice the background level (NYSDEC 1999). As discussed in more detail in Section P, radioactivity monitoring at landfills is recommended to avoid unintentional comingling of radioactive wastes in conventional landfills.

K. On site management of produced waters and wastewaters

Once drilling and completion have taken place, produced water will begin to be generated from the well during the flowback period, and later during the production phase. Flowback and produced water are not distinct wastewaters. The definition of flowback water is imprecise and can vary from well to well. It is sometimes operationally defined as water returning after the well completion for the first 10-14 days. It can also be defined as water returning after the completion and before the well head is installed for production (which can be sooner than ten days after completion). Because there is no consensus on when the transition from flowback to produced water occurs, and the water quality of both can vary significantly over time, flowback and produced water should not be treated as distinct classes of wastes. If distinction is desired, for example, because flowback may be higher quality (lower salts) and thus have alternative disposal options, the distinction should be made based on the quality of the water (i.e., a specific concentration of salts or specific chemicals such as strontium or NORM), not its classification as either flowback or produced water.

Direct discharge of drilling wastewaters at the development sites is precluded by federal law[25], which requires zero discharge from onshore gas wells (see Section C). Thus, all produced water must be collected and stored for either reuse on-site or shipment off-site for treatment or disposal. Treatment and disposal off-site are discussed in section L below.

Significant quantities of water initially return to the surface. The volumes of produced water can vary considerably in different shale gas plays and even in different wells in the same formation. Typically 10-25% of the injected water returns to the surface as flowback during the pre-production phase (Hayes and Schroeder 2009). Marcellus formation wells have reported lower (10-15%) flowback rates, however (Hoffman 2010, Mantell 2011). Thus, on-site storage of significant volumes of produced water must be accommodated immediately after well completion. This has typically been accomplished in open impoundments where produced water is mixed with freshwater for makeup of the next well completion, however we strongly recommend that well pads sited in wet climates such as western Maryland utilize closed waste tanks for wastewater containment (with adequate secondary containment). Secondary containment (including dikes, liners, pads, curbs, sumps and other relevant structures) should be employed to minimize the potential for accidental releases of production wastes from these containment facilities.

Despite the challenges associated with on-site management of large volumes of produced water, recycling this water for use in subsequent hydraulic fracturing operations either on the same site or at another site is an obvious best practice. Water produced in the flowback period can be stored on-site for use in a subsequent completion without any transport costs. Minimal treatment is necessary (e.g., settling) prior to dilution with additional freshwater for the next completion (Blauch 2010, Grottenthaler 2010). Recently Pennsylvania issued a general permit (WMGR1221) that covers treatment of produced water for subsequent reuse in hydraulic fracturing and encourages 100% recycling for water produced at well pads under development. It is not clear how such water is tracked or reported in Pennsylvania, but most large companies report nearly 100% recycling of early phase produced water (i.e., flowback) (Grottenthaler 2010,

[25] 40 CFR §435.32.

Veil 2010). Maryland should include a very strong preference for on-site recycling in permitting shale gas development.

Reuse in subsequent activities is the best management practice for later produced water as well, provided active new well development is taking place within the region and shipment distances are reasonably short. This is principally a logistical challenge, although trucking produced water increases both costs and the risks of spills during transit. While produced water is much saltier, its volume is quite low—often less than 200 gallons per million cubic feet (MMCF) of gas is reported in the Marcellus region (Mantell 2011). Thus, extensive dilution would occur in creating the next makeup water to achieve the necessary volumes for a completion. Many drillers have current goals of 100% recycling of all produced water, however this management option will not be economical if newer drilling pads are sited long distances from existing producing wells. This may not be a huge problem in Maryland, especially if MSGD can be sited in clustered industrial developments as discussed in Chapter 1. Produced water can also be treated off-site and returned for reuse at the same pad or to other well pads (as discussed in Section L below). This approach is common in Pennsylvania where centralized treatment plants offer partial treatment of produced water (removal of everything except monovalent ions: Na^+, Cl^-, Br^-) with return of the highly saline water to the well pads for reuse. Maryland should include a strong preference for reuse of produced waters for subsequent shale gas activities, but should consider whether cross-state transfers of produced waters should be permitted for this purpose. Given western Maryland's centralized location between two neighbor gas-producing states, this might be an efficient option. Permit applications should definitely include plans for produced water reuse and should specify which wells, within defined distances, will share water for reuse.

L. Management of produced water (including recordkeeping, manifesting)

As noted in Section K, there is no generally accepted definition of flowback and no legal definition that distinguishes between flowback and produced water. Best management practices should not attempt to distinguish based on these imprecise classifications but rather should refer to water quality characteristics if distinct handling is warranted. In most cases, management of the two wastewaters should be similar. Flowback may contain lower concentrations of salts, but higher concentrations of residual chemicals from the original hydraulic fracturing fluids. Produced waters generally become more concentrated in salts over production time; NORM may also increase with time in the produced water.

Wastewaters produced during oil and gas development in the U.S. are considered non-hazardous by statutory exemption from RCRA[26]. As a non-hazardous waste, oil and gas production wastes are subject to different requirements for generation, transportation, treatment, storage and disposal. Maryland has been authorized by the USEPA to operate its hazardous waste regulatory program in lieu of the federal government, based in part on state regulations being at least as stringent as corresponding federal regulations. In some instances, Maryland's regulations are more stringent than federal regulations as is allowed by federal law; Maryland has adopted the

[26] "Identification and Listing of Hazardous Waste; 40 CFR 261.4(b): Exclusions: solid wastes which are not hazardous wastes". 40 CFR 261.4(b)(5)

exemption for exploration and production wastes associated with oil and gas development, however[27].

Some testing is generally undertaken to evaluate usability for recycling at treatment plants accepting these wastes to determine if they can be adequately treated by the methods employed at the plants. Wastes that do not meet certain criteria will not be accepted at certain treatment plants. Similarly, some testing is undertaken at deep well injection sites to determine if any treatment is necessary to avoid well clogging during injection. Results of this type of testing are used internally at these facilities. They are not reported to any regulatory agency, nor are they necessarily kept beyond the decision-making process. Trucks transporting any wastewater are required to carry manifests regarding their cargo, but are not required to be placarded as hazardous. Maryland should review its requirements for testing and manifesting of hazardous and non-hazardous waste to determine which regulatory structure applies to oil and gas produced wastes.

Volumes of produced water from each well are generally reported on regular intervals to the state. These reports include the well number, volume of produced water, and the name and location of the waste operator to whom the water was taken (e.g., waste treatment facility, underground injection well site, etc.). If produced water was reused rather than disposed of, this is also noted, although in Pennsylvania the location of the reuse is not specified. These reports are tabulated in Pennsylvania and released to the public (via a web site) twice a year. It is not possible using Pennsylvania data to track water from extraction to use to reuse or ultimate disposal. A water balance for the industry cannot be completed because of insufficient detail in the water withdrawal plans (which withdrawals are for which wells) and insufficient detail on the reuse of flowback and produced water within multiple wells prior to ultimate disposal. In West Virginia, additional transportation records are required that might allow tracking of water from original withdrawal to final disposition, although the state does not undertake to evaluate water use and wastewater generation in this way. Maryland should require reporting of produced water volumes from every well, including the well location, the company providing transport of the produced water and the ultimate disposition of the waste, including the location of the subsequent well if the produced water was reused in hydraulic fracturing.

In many areas of the country, road spreading of oil and gas brines is used for dust control or deicing. Generally due to higher levels of residual fracturing chemicals, this is not permitted for early produced water (i.e., flowback), but is commonly practiced with the low volume, high salt water that returns during the production phase. Spreading on roads within the oil and gas development region (often dirt roads created by the drilling companies), as well as in surrounding rural areas, is not uncommon. In Pennsylvania and West Virginia this activity is permitted for certain brines. Clearly, surface applications to roads or land will result in eventual runoff and entry of constituents present in the brine into the surface and ground water systems. Brines from the Marcellus formation contain very high concentrations of salt and are not appropriate for open discharge to the environment, particularly given western Maryland's dependence on drinking water obtained from private groundwater wells and surface water obtained from headwater streams. Road spreading of the original produced water or any residual of its treatment should be prohibited. Several treatment facilities have suggested the creation of a

[27] COMAR 26.13.02.04-1A(5)

salt product that would be suitable for road application through treatment of gas well brines. This should only be permitted if the created salt is low in bromide and iodide and replaces a conventional salt product already being used in the region. Underground injection is the common final disposal option for produced water in the U.S., and it is also appropriate for liquid residuals from treatment operations (e.g., highly concentrated brines). We discuss this option further in section N below, but it is unlikely to be used in Maryland.

M. Treatment of produced water[28]

Produced water can be treated using a variety of chemical and physical processes to remove contaminants. Generally, radionuclides and multivalent metal ions are relatively easy to remove through coagulation, precipitation and filtration. Organics and oils can be removed through skimming or sorption. Monovalent ions (Na^+, Cl^-, Br^-) are particularly difficult to remove, requiring either membrane or thermal technologies that are energy-intensive. Concentrations of salt in produced water from the Marcellus formation in Pennsylvania and West Virginia are too high for membrane systems such as reverse osmosis; therefore, thermal technologies, including evaporation, multi-state flash distillation, and humidification-dehumidication methods, are the only viable treatment technology for the simple salts (Hayes 2009). Thermal desalination results in either an even more concentrated brine solution or a solid salt product as a residual. These residuals must be managed while the desalinated water can either be reused or discharged through a NPDES permit to surface water.

Typically, partial treatment for recycling can be performed on-site (as described in section K), but all other treatment methods typically take place off-site. Produced water is picked up from a number of wells in tanker trucks on a regular schedule and taken to a centralized brine treatment plant. There are no permitted centralized brine treatment plants currently in Maryland. However, there are plants in West Virginia and Pennsylvania, and additional plants have been opening in response to additional produced water volumes requiring management. Two types of plants are operating in Pennsylvania. A few brine treatment plants that were operating before regulatory change to discharge standards on salt continue to operate without TDS limits for their discharge. These plants remove most contaminants except monovalent ions (Na^+, Cl^-, Br^-), and discharge the residual high salt brine to surface waters (creeks and rivers). However, these surface discharging plants no longer receive Marcellus formation produced water as the PA DEP requested that drillers stop using this disposal method. In Pennsylvania, new treatment plants must meet a discharge limit of 500 mg/L TDS. Maryland does not have a numerical criterion for TDS (or specific conductance—a related parameter) for in-stream water quality or for discharge permit limits. We do not recommend the use of brine treatment plants that partially treat produced water and discharge high concentrations of salt to the environment in Maryland. To avoid salt discharges into critical drinking water areas, prior to approving brine treatment plants, Maryland should enact a discharge permit limit for TDS and in-stream standards for TDS, chloride and bromide. Under no circumstances should Maryland allow discharge of partially-treated brine or residuals from brine treatment facilities into the waters of the state. Further, 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.

[28] An extensive review of treatment options is provided in Hammer et al. (2012).

Other brine treatment plants operating in Pennsylvania and West Virginia do not discharge wastewater to the environment. They treat produced water to remove metals and organics, and return the brine containing only monovalent ions to drilling companies for reuse. This is very similar to the on-site partial treatment for reuse discussed in Section K. Because this treatment requires additional transportation of the water (and adds to the associated impacts and risks), off-site treatment for reuse would be an even poorer option than on-site reuse in Maryland. However, if on-site treatment were deemed infeasible or off-site treatment facilities were closer than subsequent wells requiring water for reuse, such treatment plants could play a useful role.

Materials removed from the water as sludges during treatment processes are typically dried and disposed of at landfills. Some of these treatment plants have plans to add additional treatment to desalinate water to acceptable discharge levels; however, such second stage treatment is not operational at most plants in Pennsylvania due to low demand for that type of extensive treatment. If the market for partially-treated water for reuse declines, these plants will likely offer full distillation services, but this will increase the treatment costs significantly. Distillation will produce highly concentrated brines or solid salts that will require subsequent management, either at deep well injection sites or landfills. The potential to create usable salt products from this process has been discussed, but technological and regulatory hurdles remain. Best management practices for residuals are discussed below.

During the recent rapid expansion of development in the Marcellus formation in Pennsylvania, another management method for produced water was used. Produced water was sent to conventional wastewater treatment plants, classified by USEPA as publicly-owned treatment works (POTWs). These plants treat domestic sewage and are not designed to remove chemicals from oil and gas brines. However, relatively large wastewater volumes diluted the salts, and this method was considered acceptable as long as brine flows were low. In 2008 and 2009, many POTWs in Pennsylvania were accepting higher flows than their wastewater could adequately dilute. Concentrations of salts in the receiving waters rose unacceptably high in the fall of 2008. Concentrations of bromide, an ion with implications for drinking water treatment, rose as well. The PA DEP intervened in 2008 and 2009 to restrict use of POTWs for brine treatment. USEPA has also provided clarifications regarding the acceptance of oil and gas wastewaters and made substantial changes that required permit modifications[29]. In 2011, PA DEP requested that Marcellus wastewater not go to any surface-discharging POTWs without a TDS standard in their permit. Anecdotally, TDS and bromide levels have reportedly been lower in 2012 in some waterways (e.g., the Monongahela), but not in others (e.g., the Allegheny) following these changes[30]. In addition to Pennsylvania, Ohio is considering use of POTWs for brine treatment and disposal, and several lawsuits surrounding this situation are pending in that state.

Following concerns regarding the use of POTWs, often without pretreatment of the produced water, the USEPA announced plans to develop pre-treatment requirements for oil and gas wastewaters being sent to POTWs (USEPA 2011). These rules are pending at this time. If promulgated, the rules would specify pre-treatment methods or water quality criteria for pre-

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[29] Ibid., 5

[30] To the best of our knowledge, these data have not been published in the peer-review literature, but the situation was widely covered in press accounts.

treated wastewater that would be sent to POTWs. These rules are unlikely to address all trace constituents of concern in produced water, as POTW treatment relies heavily on dilution to manage low concentration pollutants. For example, it is unclear if pre-treatment rules would consider bromide, a low concentration pollutant of concern only for downstream drinking water plants.

Use of POTWs for dilution of produced water from oil and gas development is not a best management practice. Disposal practices that load salts (especially those containing chloride and bromide) to surface waters that are used for drinking water sources should not be permitted. This activity impedes treatment of water to provide water that is potable and safe for consumers. Higher chloride levels cause taste and odor problems in finished water. High bromide levels lead to increased formation of carcinogenic disinfectant by-products that can persist in the water to the point of consumption. Treatment of produced water by POTWs and other conventional wastewater treatment methods that do not remove salts should be prohibited in Maryland.

A significant concern for any treatment method is the production and management of residuals. For most treatment systems, solids are removed into wet sludges, which can be disposed of in landfills as non-hazardous wastes. Treatment residuals created from exempt oil and gas produced waters are also exempt from federal laws related to hazardous waste, provided the exempt waste is not mixed with a non-exempt waste prior to the treatment process[31]. Maryland has not objected to the 'derived from' interpretation in RCRA that exempts residuals produced from exempt wastes. Treatment residuals will contain removed contaminants such as NORM, heavy metals, organic compounds, and salts, and these residuals should be evaluated for their constituents and managed accordingly. Since treatment residuals will generally have more concentrated levels of contaminants found in the original wastewater, deep well injection disposal is the preferred management strategy.

N. Disposal of produced water or residual treatment wastes

Most produced water, as well brine residuals from treatment of produced water, in the U.S. is disposed of through deep injection in Underground Injection Control (UIC) Class II wells specifically designed for disposal of brines and other fluids associated with oil and gas production, following requirements of the Safe Drinking Water Act of 1974 (Part C § 1421-1426). The Marcellus region does not have an extensive deep well injection infrastructure. Pennsylvania has only a few UIC Class II wells that are mostly privately owned. West Virginia and Ohio have considerably more such facilities, including both private and commercial facilities. In general, trucking costs can make this disposal option prohibitively expensive for development in neighboring states. Concerns in Ohio regarding earthquakes associated with underground injection have also limited the new citing of commercial disposal wells. Maryland does not have a single UIC Class II disposal well. At present, disposal through deep well injection will require either trucking wastes to neighboring West Virginia or siting, permitting and drilling injection wells within Maryland. Maryland may prefer to develop UIC Class II injections wells to avoid long distance trucking of produced waters. However, these wells are commonly sited in played out areas of gas development, which Maryland does not have, or in areas that are also suited for gas storage, which Maryland is currently using for such purpose.

[31] 58 FR 15284, 15285 (March 22, 1993)

We anticipate that locations in Maryland for siting injection wells may be very limited. Review of injection well concerns in neighboring states and geological survey of Maryland subsurface formations should be undertaken prior to consideration of this activity in Maryland. Further, Maryland should review the relevant regulations surrounding development and use of UIC 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.

O. Reclamation and closure (decommissioning)

In general, once production begins, interim reclamation of the site can be achieved through re-vegetation and modifications to the stormwater management systems as discussed earlier (Section C). This should normally take place within 60 days of the initiation of gas production, and the operator should submit a site restoration report to the state. Interim reclamation of the site after completion restores the disturbed land but allows continual access for collection of produced water, transport of gas (via gathering pipelines) and access for any future well reworking, if necessary. Road access must be maintained, but other areas of the site that were disturbed for heavy equipment needed during drilling and completion should be regraded and revegetated. All solid wastes should be disposed of using methods appropriate for the waste type, following state regulations. Residuals from gas drilling activities should be evaluated for their constituents to determine their status as hazardous wastes and managed accordingly. Water storage impoundments should be closed and these disturbed areas reclaimed. Pit liners should be removed and landfilled off-site. On-site disposal of residuals should not be permitted. Stormwater management for control of erosion and sedimentation should continue until the site is fully reclaimed. In Chapter 1 we discussed the rationale behind allowing development at multi-well pads to proceed more cautiously (especially as the first wells are drilled and the productive capacity of these wells is ascertained) and some of the ramifications for such a process from the standpoint of interim reclamation. We recommend that Maryland study very carefully how the development process at multi-well sites has taken place in other states (particularly Pennsylvania) and establish suitable regulations that balance the need to keep well pads completely operational for extended periods of time against the goal of ensuring that partial reclamation of these sites is not unduly delayed.

Once production declines, wells are sometimes shut in for possible future development (i.e., refracking or drilling again from the same well pad location). A time limit should be established for wells in this status. If no additional development takes place within 12 months, site reclamation must begin unless an extension is issued by the state. Once no further well production is expected, final reclamation of the site should take place. As discussed in Chapter 3, this requires plugging the well to ensure isolation from the surface and near surface environments—a critical process in preventing water quality impacts from movement of residual gas or brine in the formation (as well as unintended losses of the gas resource). Permanent signage should be left in place to allow the well to be located if necessary in the future. Restoration plans should be developed in detail and submitted to the state. They should include stabilization and revegetation of all disturbed areas, including recontouring to reestablish the original topographic contours, use of native plant species and use of agency-approved seeds, and removal of all surface components of the facility (see Chapter 1). The goal of reclamation should normally 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.

Improperly closed wells have led to significant environmental impacts in oil and gas states in the past (including Pennsylvania and West Virginia[32,33]) and thus should be avoided. Detailed, proscriptive methods for well closure should be developed through review of industry best management practices and other state regulations (see Chapter 3). Maryland should take a proactive approach to regulation in this area. With the implementation of best practices in well closure, Maryland should be able to avoid the problems that other states have experienced throughout their long oil and gas development histories.

P. Naturally occurring radioactive materials (NORM)

Shale gas formations often contain naturally-occurring radioactive materials (NORM) and drill cuttings and production brines can contain NORM. NORM should be assessed in all components of waste associated with gas production from shale. A 1999 study in New York State is a model for assessment of the industry for NORM concerns (NYSDEC 1999). Extensive on-site sampling and monitoring found NORM levels near background at most oil and gas production sites. Similar monitoring should be routine at MSGD sites to ensure adequate protection of workers and the environment.

Oil and gas production wastes that exceed target levels should be reclassified as radioactive waste (RW) and not fall under the federal exemption of oil and gas production wastes[34]. Similarly, when drill cuttings and production wastes are treated or disposed of, residuals from these processes can become enriched in NORM (then called technologically-enhanced, naturally-occurring radioactive materials or TENORM). This enrichment process should be monitored and, if necessary, residuals should be reclassified as radioactive waste (RW) to ensure they are tracked and protective disposal practices are used. All drilling wastes should be evaluated for the presence of NORM to ensure adequate disposal. Pennsylvania landfills have utilized radiation detection systems to ensure that radioactive wastes are not incorrectly comingled with conventional non-hazardous solid waste (PADEP 2012). Programs to monitor for radioactive waste at landfills should be adopted in states where shale gas drilling wastes may be sent to landfills. Maryland should adopt monitoring at solid waste disposal landfills for radioactivity.

If NORM or TENORM waste associated with oil and gas production or waste treatment contains levels of radioactivity that would result in classification as low-level radioactive waste (LLRW), these residuals should be treated in accordance with LLRW regulations. LLRW generated in treatment of produced water from MSGD in Maryland would likely be disposed of outside of the state. The Appalachian States Low-Level Radioactive Waste Commission is an interstate agency established to assure interstate cooperation for the proper management and disposal of low-level

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[32] Methane Emissions Project, Borough of Versailles, Pennsylvania. Available on the web at: http://www.netl.doe.gov/newsroom/versailles/Versailles%20Methane%20Emissions%20Project%20-%20Final%20Report.pdf

[33] PA Department of Environmental Protection, Bureau of Oil and Gas Management, Stray Natural Gas Migration Associated with Oil and Gas Wells, available on the web at: http://www.dep.state.pa.us/dep/subject/advcoun/oil_gas/2009/Stray%20Gas%20Migration%20Cases.pdf

[34] Federal Low Level Radioactive Waste Policy Act specifically exempts NORM.

radioactive wastes. The Commission identified Pennsylvania as the host state to receive and dispose of radioactive waste from the party states (Delaware, Pennsylvania, West Virginia and Maryland). Maryland producers of LLRW can also contract with out of state facilities through approval by other interstate commissions (e.g., Texas compact).

Gas operations are typically short term and thus, build up of NORM at a given site is not expected; however, equipment is moved from site to site and could develop scale that incorporates NORM. Oil and gas production equipment should be assessed at regular intervals. Tanks on-site holding produced water could also develop precipitates with time that contain NORM. Regular inspections and cleaning of equipment and facilities that might be susceptible to the development of TENORM are recommended as part of best management practices for the on-site management of produced water.

Q. Key recommendations

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 groundwater), respectively.

4-B We support Maryland Environmental Code § 14-110.1 (H.B. 1123) and recommend pre-development notification should be made to public and private drinking water well owners.

4-C Pre-drilling groundwater 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 groundwater would be to require post-drilling 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.

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 (e.g., forest management, MSGD, etc.) conducted in Tier II watersheds meet an anti-degradation standard.

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.

4-F Post-construction inspections of stormwater structures should occur prior to well drilling and completion.

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.

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.

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.

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 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.

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5. Protecting terrestrial habitat and wildlife[1]

Despite high levels of development in many areas of the state, western Maryland (Allegany and Garrett County) remains a largely intact landscape relative to other regions of the eastern United States[2]. The dominant land cover type of the Appalachian mountains of western Maryland is forest (>75%; Figure 5-1), including extensive areas of forest interior habitat (Figure 5-2). The total extent of habitat loss potentially caused by Marcellus Shale gas development is anticipated to be small relative to other forms of land conversion in the state (e.g., urban/suburban development, surface mining for bituminous coal), but not insignificant (e.g., Drohan et al. 2012). We estimate that with careful planning new disturbances could be less than 1-2% of the land surface (see Chapter 1). Nevertheless, not all forests are of equal value, and rare or sensitive forest habitat should be avoided. Beyond the direct loss of habitat, many species in western Maryland are potentially sensitive to new construction that reduces the amount of core and connected habitat, creates opportunities for direct exposure to toxic contaminants, provides opportunities for biological invasions, or alters the soundscapes and night-time lightscapes. Eighty-seven animal species and 117 species of plants are currently listed as rare, threatened, or endangered within Maryland's Marcellus Shale region (Appendix 5A). Many of the recommendations in this chapter are aimed at minimizing the fragmentation of the forested landscape with special emphasis on protecting irreplaceable habitats and imperiled terrestrial biota. Forest protection is also protective of downstream aquatic resources (Chapter 6), and practices such as the preservation of forested riparian buffer are important to both terrestrial and aquatic resources. In general, no-net-loss of forest is a goal consistent with the state's overall resource stewardship and a useful guiding principle for shale gas development in western Maryland.

A. Well pad spacing and siting

Any surface disturbance that punctures intact forest provides an impact that is greater than the amount of forest loss alone (Harris 1984). For example, a 1% net loss of total forest, as was observed for the conterminous United States from 2001 to 2006, can translate to net losses of as much as 10% of forest interior area (Ritters and Wickham 2012). A tentative pattern has been reported for Marcellus shale sites in Pennsylvania that interior forest loss is approximately twice that of the overall forest loss (Slonecker et al. 2012). Another recent study in Pennsylvania found that Marcellus well pads and associated infrastructure (roads, water impoundments, and pipelines) required approximately 9 acres per well pad with an additional 21 acres of indirect edge effects[3]. Loss of interior habitat, defined as areas of forest at least 100 m (328 ft) from the

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[2] Saylor, K.L. 2008. Land Cover Trends Project: Central Appalachians. U.S. Department of the Interior, U.S. Geological Survey, Washington, DC, USA, available at http://landcovertrends .usgs.gov/east/eco69Report.html.

[3] Johnson, N. 2010. Pennsylvania energy impacts assessment, Report 1: Marcellus Shale Natural Gas and Wind, The Nature Conservancy, Pennsylvania Chapter, and Pennsylvania Audubon, http://www.nature.org/wherewework/northamerica/states/pennsylvania/news/news3511.html.

forest edge (Harper et al. 2005), can limit the ability of forests to support ecological functions due to edge effects (Figure 5-2). Edge forests tend to have more invasive species, higher rates of atmospheric deposition, greater levels of light, increased predation, and altered biochemical cycling among other differences with forest core (Harper et al. 2005). To minimize these disturbance and edge impacts, New York State encourages well pads spacing to be clustered to minimize the total surface disturbance (NYSDEC 2011). The Pennsylvania DCNR Bureau of Forestry requires approval of spacing for any leases on State Forest Land and also promotes centralization of well pads (PADCNR 2011). As discussed in Chapter 1, multi-well pads are highly encouraged because they increase the regulatory efficiency for operators along with minimizing surface disturbance (NYSDEC 2011).

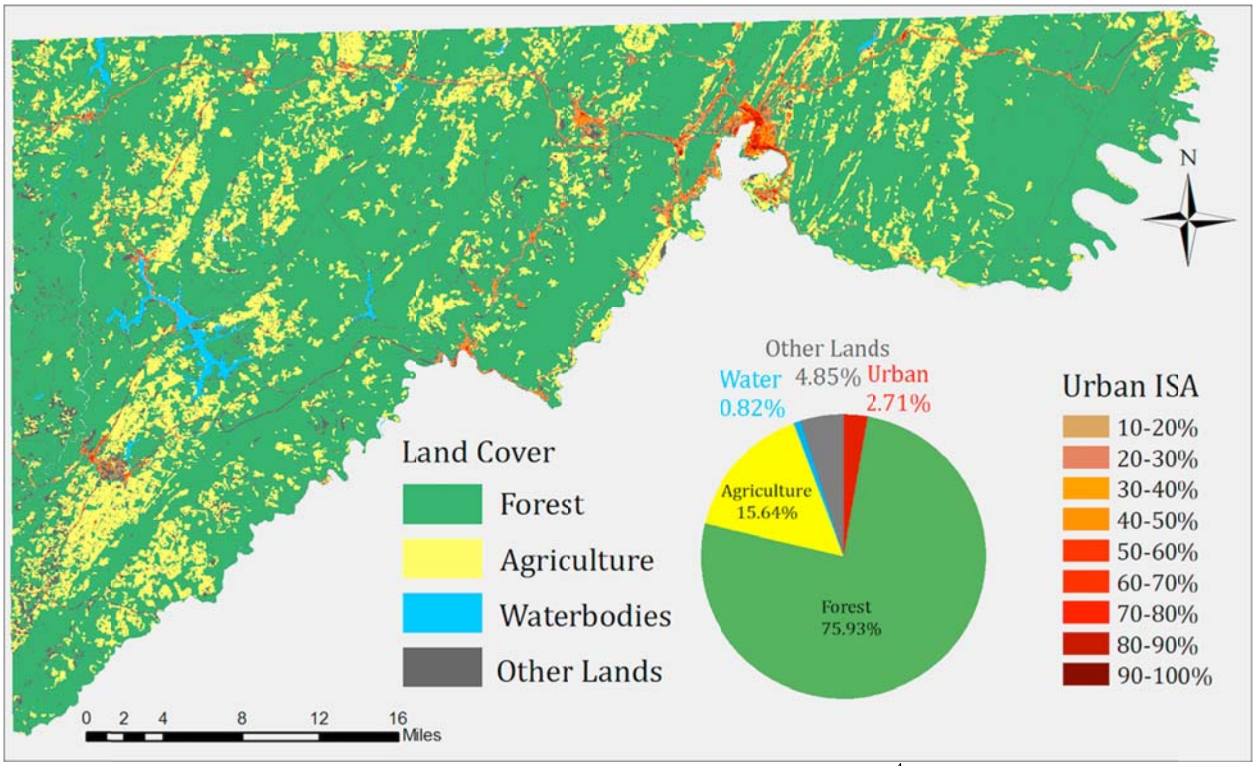

Figure 5-1. Land cover map of Allegany and Garrett County (Source: NLCD 2001)[4]. Over 75% of the landscape is covered by forest. Statewide, Maryland is dominated by agricultural land and less than 40% of the state is forested. Urban and other lands comprise 7.5% of the western Maryland, with urban ISA representing the percentage of each 30 m cell that is covered by impervious surfaces.

The siting of well pads also is addressed in Chapter 1. In general, open lands are preferred for development over forestlands. Pennsylvania emphasizes that well pads should be located in a manner that reduces impacts to forested areas, preferably in already disturbed lands (PADCNR 2011). Upland core forests of Appalachia protect warblers and other species of special concern, while cove forests of the region are highly diverse and productive due to their high moisture and soil fertility (Wickham et al. 2007, Maxwell et al. 2012). However, it should be noted that some

[4] Throughout this report the NLCD 2001 is used to illustrate patterns of land-use and land-cover. At this scale, the NLCD 2001 is indistinguishable from the NLCD 2006. Any subsequent mapping completed to support the regulation of MSGD and/or the protection of natural resources should use the most up-to-date and scale-appropriate data available.

grassland bird species are listed as rare in Maryland (e.g., the Upland Sandpiper), which could limit the siting of MSGD in some non-forest areas. Optimally, well pads and associated facilities should be sited in industrial parks designed and zoned for this type of industrial activity, and/or in close proximity to major interstate highways and exit ramps designed to efficiently handle round-the-clock transportation.

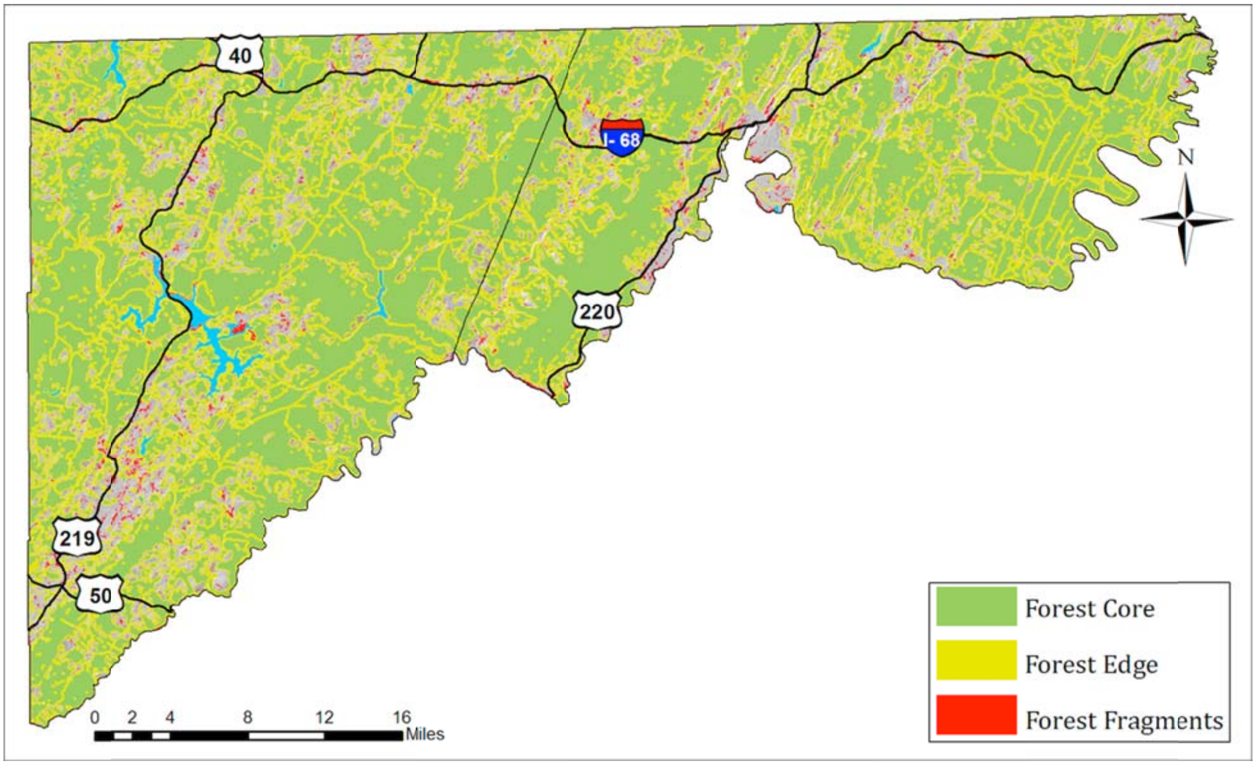

Figure 5-2. Forests of western Maryland classified as forest core (green), edge (yellow), and fragment (red) assuming a depth of edge influence of 328 ft (Source: NLCD 2001). Of the approximately 815 square miles of forest in Allegany and Garrett counties, 60% is core, 38% edge, and 2% fragment by this criterion.

Under the Maryland Forest Conservation Act (FCA) of 1991, any activity requiring an application for a subdivision, grading permit or sediment control permit on areas 40,000 square feet or greater (approximately 1 acre, or about ¼ the area of a typical drill pad site) requires a Forest Conservation Plan. Although the FCA does not specifically call for no-net-loss of forest in Maryland, the required Forest Conservation Plan does include tree protection specifications, mitigation planting, and a long-term protection agreement that is placed on the retained forest and mitigation areas. The Act is at least partially responsible for reversing the rate of forest loss in the state from a high of 0.6%/year in 1990 to 0.1%/year 2002[5]. In 2008, Maryland Senate Bill 431 created a task force to develop a plan to implement a no-net-loss of forests policy for Maryland. A key finding of the task force was that:

> *Maryland needs to move toward a No-Net-Loss of forests as a strategic component in the effort to restore the health of the Chesapeake Bay and its watershed and promote the economic well-being of rural Maryland with strategies and policies that measurably contribute to enhanced forest land retention and improved forest land stewardship without negatively impacting productive agricultural*

[5] Maryland No Net Loss of Forest Task Force Final Report and Recommendations. January 2009. http://www.dnr.maryland.gov/dnrnews/pdfs/NNLTFFINALREPORT1.pdf

> *lands. Such efforts must be conservation oriented rather than preservation oriented in nature to be able to sustain native plant communities in a developed landscape.*[6]

Unfortunately, Allegany and Garrett County are currently exempt from the Maryland FCA because of their high percentages of forest land-cover and perceived lack of threat from residential development relative to the rest of the state. Marcellus shale gas development represents a new land-cover change process on these landscapes. Therefore, Maryland should consider adopting a no-net-loss of forest approach to Marcellus Shale gas development. The primary mechanism for implementing this approach would be through the requirement of forest plantings elsewhere in Maryland to mitigate any well pad or related MSGD that remove forest from the landscape. The requirement might be best implemented by expanding the FCA to include the two counties of western Maryland. Regardless of the mechanism, the siting of mitigation plantings should consider regional conservation goals and water quality improvement potential. Clearly such an approach would help to incentivize the siting of well pads and other infrastructure on non-forest lands.

Following the examples of Colorado and as proposed in Pennsylvania, Maryland might consider well-pad permitting as part of a comprehensive gas development planning process (described in Chapter 1). New York State law allows the environmental impact of more than one project to be considered at the same time (Strong 2008). A small project may not have a negative impact on habitat alone, but when considered in the context of nearby or related projects, the negative impact may be significant. With respect to terrestrial habitat, a comprehensive gas development plan could help channel development into areas with greater amounts of existing disturbance and avoid areas with intact forests (especially forest interior habitat and other high priority conservation areas). Efforts in this area would greatly improve Maryland's ability to address cumulative impacts of MSGD which are likely to be significant without proper regulation.

B. Impoundments

Direct exposure to contaminated water stored on-site and during transportation on- and off-site can come from tank leaks and spills during tank transfers, and is one of the biggest threats to wildlife from hydraulic fracturing operations (Thompson 2012). Although many of the chemicals contained in hydraulic fracturing fluids are potentially toxic to wildlife, there are few studies on the exposure effects of gas operations to animals. One recent study of farm animals in six states (Pennsylvania, New York, Ohio, Colorado, Texas, Louisiana) suggested increased mortality rates in livestock and companion animals (i.e., dogs and cats) living close to active gas-drilling operations (Oswald and Bamberger 2012), with several caveats associated with the lack of controls due to the case study aspect of the survey (Thompson 2012). Although chemicals can be volatized (e.g., by impoundment aerators) and misted into the air creating an inhalation exposure pathway, the most common source of toxicity exposure was likely via contaminated water. Pathways of exposure included, for example, spills of hydraulic fracturing fluids, tears in the liners of wastewater impoundments, and spreading of wastewater on roads to reduced dust and ice followed by animals licking their paws after crossing the roads (Table 5-1). Health impacts

[6] Maryland No Net Loss of Forest Task Force Final Report and Recommendations. January 2009. http://www.dnr.maryland.gov/dnrnews/pdfs/NNLTFFINALREPORT1.pdf

ranged from neurological to sudden death with the most common effects being reproductive. Animals affected include cows, horses, goats, llamas, chickens, dogs, cats, and koi. Because the movement of farm animals is confined they may experience higher cumulative exposure than wildlife with less restricted mobility. However, photographic evidence has been reported of dead and dying songbirds, deer, frogs, and salamanders (Oswald and Bamberger 2012). The lack of controlled dose-response studies is due in part to the lack of information on the specific chemicals used in the hydraulic fracturing. Additionally, substances that occur naturally in the shale may come to the surface as part of the process. These constituents are poorly quantified, but can be equally or more toxic than the hydraulic fracturing fluid.

Table 5-1. Case survey documenting impacts to farm animals living near gas drilling operations (Oswald and Bamberger 2012).

Source of exposure	# of cases
Hydraulic fracturing fluid spill from holding tank	2
Drilling fluids overran well pad during blow out	1
Storm water run-off from well pad to property	3
Wastewater impoundment leak	1
Wastewater impoundment allegedly compromised	1
Wastewater spread on road	2
Wastewater dumped on property	1
Wastewater dumped into creek	3
Wastewater impoundment not contained	3
Well/spring water	17
Pond/creek water	8
Pipeline leak	1
Compressor station malfunction	2
Flaring of well	3

To limit the exposure of wildlife to toxic chemicals, impoundment ponds used to store flowback and produced wastewater should not be permitted in Maryland. Evaporation in wastewater impoundments can increase the concentration of some toxins, making them fatal traps to migratory birds and other wildlife that may try to use the ponds[7]. In the State of New York's revised guidelines, watertight tanks are the preferred option to store flowback and produced water (NYSDEC 2011). Pennsylvania DCNR recommends the following steps to protect ecological resources from off-site spills: (1) use of double-wall tanks for the storage of chemicals and liquids; (2) wherever possible, chemicals and liquids should be stored inside storage trailers (PADCNR 2011). Closed storage tanks with secondary containment should be used for all storage of chemicals and produced waters, especially in areas with significant rainfall such as western Maryland (see Chapter 4). Where impoundments are used (e.g., for temporary storage of freshwater only) fencing of these water features and freeboard of several feet should be maintained. The construction of any impoundments should consider the increases in storm intensities that are projected as a consequence of the state's changing climate (Boicourt and Johnson 2010). Runoff and spill prevention, response and remediation plans should be a necessary part of the permitting process. Finally, to protect wildlife and downstream water quality, spraying of wastewater (flowback or produced water) on roads to minimize dust, for example, should not be permitted under any circumstances.

[7] Ramirez, P. 2009. Reserve Pit Management: Risks to Migratory Birds. U.S. Fish & Wildlife Service, Region 6, Environmental Contaminants Program, http://www.fws.gov/mountain-prairie/contaminants/documents/ReservePits.pdf

C. Riparian setbacks

Forested riparian buffers enhance biodiversity by (1) providing foraging, nesting, brooding, thermal, and escape cover; (2) protecting sensitive habitats; and (3) maintaining landscape connectivity (Bentrup 2008). These terrestrial habitats also provide valuable buffer benefits to aquatic environments, for example, by shading streams to maintain favorable temperature (Moore et al. 2005). Despite strong evidence that forested riparian buffers are an important best management practice, the scientific basis for determining a specific width for the BMP depends on the overall rational for the buffer. Much of the scientific evidence (Table 5-2) supports the use of relatively large forest buffers when the intent is to preserve biological diversity (Bearer et al. in press). For example, herptiles [i.e., amphibians (e.g., frogs, toads, and salamanders) and reptiles (e.g., snakes, turtles, and terrapins)] exhibit life stages during which individuals will migrate great distances from streams and wetlands in search of new habitat (Grant et al. 2010). In a study of marbled salamanders, over 200 juvenile salamanders were captured at distances between 365 and 4,035 ft (median = 883 ft) from natal ponds (Gamble et al. 2006). Similarly, considerable work has been devoted to evaluating the typical dispersal distances of turtles, with most recommendations for forest buffer widths falling in the range of 500-1,000 ft (e.g., Bodie 2001) which is intended to capture 95% of all migrating individuals. There is also abundant evidence that aquatic insects utilize riparian buffers during adult life stages (Bried and Ervin 2006), indicating the unique nature of riparian forests as foraging habitat for rare, threatened and endangered bats (Lookingbill et al. 2010).

Table 5-2. Representative list of studies providing evidence supporting different riparian setback widths.

Response tested	Setback recommended	Citation
Neo-tropical bird activity	330 ft	(Hodges and Krementz 1996)
Dragonfly activity	>530 ft	(Bried and Ervin 2006)
Turtle migration	910 ft	(Burke and Gibbons 1995)
Salamanders	330 ft	(Crawford and Semlitsch 2007)
Salamanders	890 ft	(Gamble et al. 2006)
Birds	660 ft	(Perry et al. 2011)
Freshwater reptiles	1,240 ft	(Roe and Georges 2007)
Salamanders	410 ft	(Semlitsch 1998)
Amphibians and reptiles	960 ft	(Semlitsch and Bodie 2003)
Wildlife	330 ft	(Wanger 1999)
Aquatic diversity	330 ft	(Castelle et al. 1994)
Amphibians and small mammals	330 ft	(McComb et al. 1993)

Many riparian areas in western Maryland are currently forested (e.g., 75.8% of the land area within 300 ft of streams is forest). Any denuded riparian zones provide opportunities for reforestation as part of our recommended no-net-loss of forest policy. Riparian setbacks would help ensure that MSGD was designed to minimize harm to this critical terrestrial habitat. We recommend minimum setbacks of 300 ft from floodplains, wetlands, seeps, vernal pools, streams, or other surface water bodies (Figure 5-3). This distance is consistent with estimated requirements from the scientific literature for terrestrial species that use riparian areas as movement corridors and amphibians, turtles and other aquatic species that use the land for at least part of their life cycles (Table 5-2). The distance is also consistent with U.S. Department of

Agriculture (USDA) recommended corridor widths for terrestrial biota (Bentrup 2008). Operationally, these setbacks could be considered minimum thresholds and would be increased by any additional requirements set by law for specific rare, threatened or endangered species, for example. Setbacks should be measured from the edge of disturbance (not the wellbore) to the specific habitat of concern. In the case of floodplains, the Federal Emergency Management Agency (FEMA) floodplain maps, which have recently been updated for both Garrett and Allegany County, could be used to delineate these habitats.

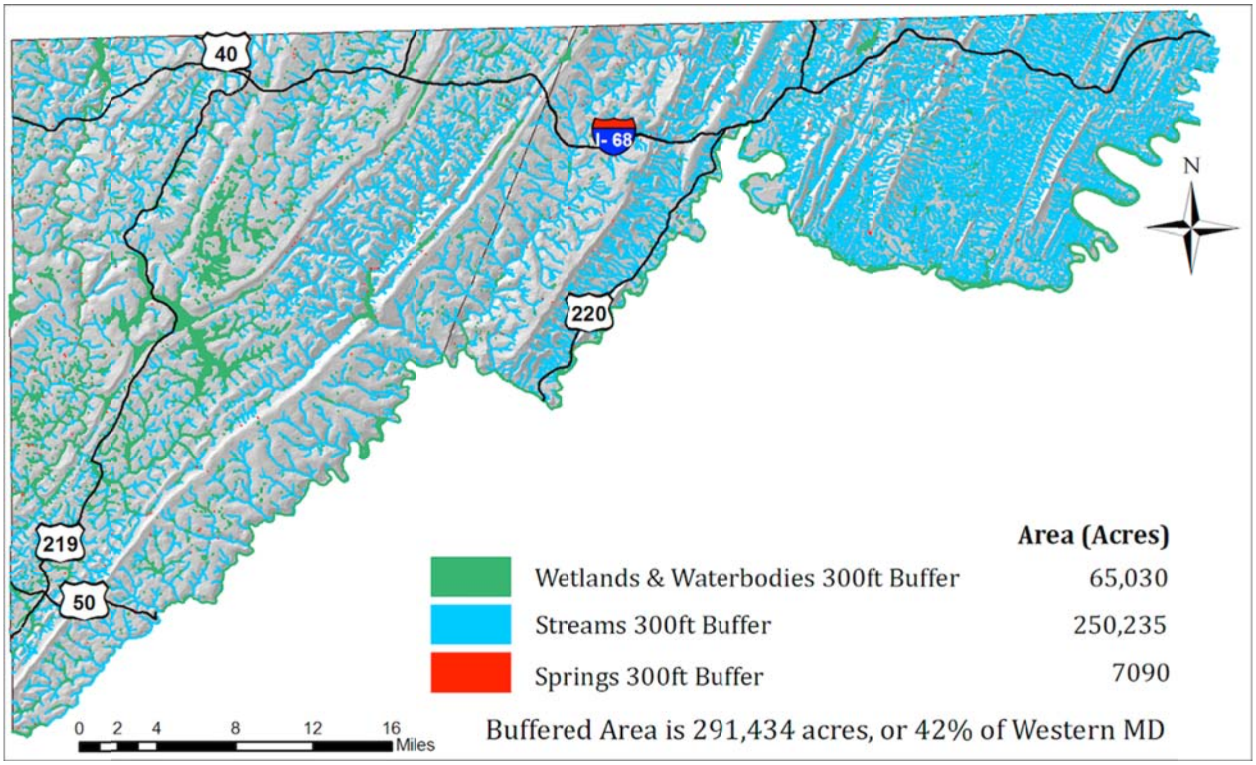

Figure 5-3. Waterways and proposed riparian buffer setbacks for western Maryland. As discussed in Chapter 6, much of the area included in these recommended setbacks is unsuitable or undesirable for multiple reasons, including designation as the 100-yr floodplain, riparian forest, or topographically steep (slope >15%) land.

D. Special protection areas

Several states have implemented additional setback requirements for forest focus areas. Pennsylvania requires that a 600 ft boundary be maintained between well pad sites and state park land or designated wild and natural areas on state forest land (PADCNR 2011). New York State's proposed guidelines designate forest focus areas based on Nature Conservancy and Landscape Connectivity Analysis. These focus areas would be subject to site-specific ecological assessment, including pre-disturbance biological studies and an evaluation of potential impacts on forest interior birds from the project. More stringent mitigation measures may then be instituted for these areas (NYSDEC 2011).

Fortunately, Maryland has already made significant progress in identifying critical areas for special protection. The Maryland Department of Natural Resources (DNR) Natural Heritage

Program has developed a digital map known as BioNet (Biodiversity Conservation Network) that effectively prioritizes areas of the state for conservation of freshwater and terrestrial plants, animals, habitats, and landscapes. The purpose of the assessment was to provide decision support for species and land conservation programs including the guidance of compatible land uses and land management practices. These data represent the most up-to-date understanding of the spatial distribution of biotic resources in the state and guide the state's overall biodiversity stewardship strategy. The criteria used within BioNet have a dual focus on the rarest species and habitats, as well as the habitats that concentrate the largest numbers of rare species and habitat. Thus, BioNet considers areas with: (1) only known occurrences of species and habitats; (2) globally rare species and habitats; (3) state rare species and habitats; (4) animals of greatest conservation need; (5) watch list plants and indicators of high quality habitats; (6) animal assemblages (e.g., colonial nesting waterbirds, forest interior species); (7) hotspots for rare species and habitats; (8) intact watersheds; and (9) wildlife corridors and concentration areas. These areas are prioritized into a five-tiered system:

- Tier I – area is critically significant for biodiversity conservation
- Tier II – area is extremely significant for biodiversity conservation
- Tier III – area is highly significant for biodiversity conservation
- Tier IV – area is moderately significant for biodiversity conservation
- Tier V – area is significant for biodiversity conservation

Areas identified include those that support the 204 state-listed species (Table 5A), rare and high quality plant and animal communities, high wildlife densities, and important habitats needed for wildlife migration and movements related to climate change. Tier I and Tier II sites represent locations that Maryland DNR has designated as "irreplaceable natural areas"[8].

Consistent with Pennsylvania state forest policy, we recommend a no-disturbance setback within and 600 ft around any priority conservation area (Figure 5-4). Priority conservation areas should be defined using the best available science and designed so that no irreplaceable areas of unique habitat could be impacted by MSGD. Portions of the BioNet dataset, specifically irreplaceable natural areas (BioNet Tier I and II sites) and wildlands should initially be considered as priority conservation areas and receive the recommended 600 ft setback. BioNet data products should be kept up to date and publically available, so that potential MSGD operators have the information required to identify lands for their activities that would have the least impact on the natural resources of Maryland. The methods used to generate BioNet products should be published in the scientific literature.

Caves were addressed in Chapter 1 while discussing potential complications arising during drilling, well casing and cementing; however, caves (including those subterranean voids that are man made) are also a terrestrial habitat of special concern. Western Maryland is home to two globally ranked species of bat that are critically imperiled in the state because of extreme rarity (Table 5-1). The Indiana bat *(Myotis sodalis*) is a federally listed endangered species in danger of extinction throughout significant portions of its range. However, even common species of cave-dwelling bats are currently in a status of extreme flux due to the poorly understood white-nose

[8] Jonathan McKnight (DNR - Wildlife and Heritage Service, Associate Director Natural Heritage Program), personal communication

syndrome that has resulted in the death of millions of North American bats (Frick et al. 2010). In response, the U.S. Fish and Wildlife Service (USFWS) called on all activities in affected areas to be curtailed[9]. Extreme caution is advisable around all Maryland caves that support obligate cave-dwelling species[10]. The true extent of caves in western Maryland is likely highly underrepresented by the 33 caves that are currently mapped in Garrett and Allegany County (Franz and Slifer 1971). Because drilling activities have the potential to add to the already significant levels of stress being experienced by cave-dwelling bat populations, pre-drilling testing should be used to identify the locations of subterranean voids, and a 1,000 ft setback should be observed around any naturally occurring cave. This recommendation assumes that all voids are connected to the surface via conduits sufficient in size to be accessible to bats. While some of these spaces may be inaccessible, hibernacula entrances can be very small and difficult to detect by simple observation of the land surface in many cases[11]. Regardless, the occurrence of voids is also indicative of potential habitat for other forms of subterranean life whose presence is not dictated by connections to the surface.

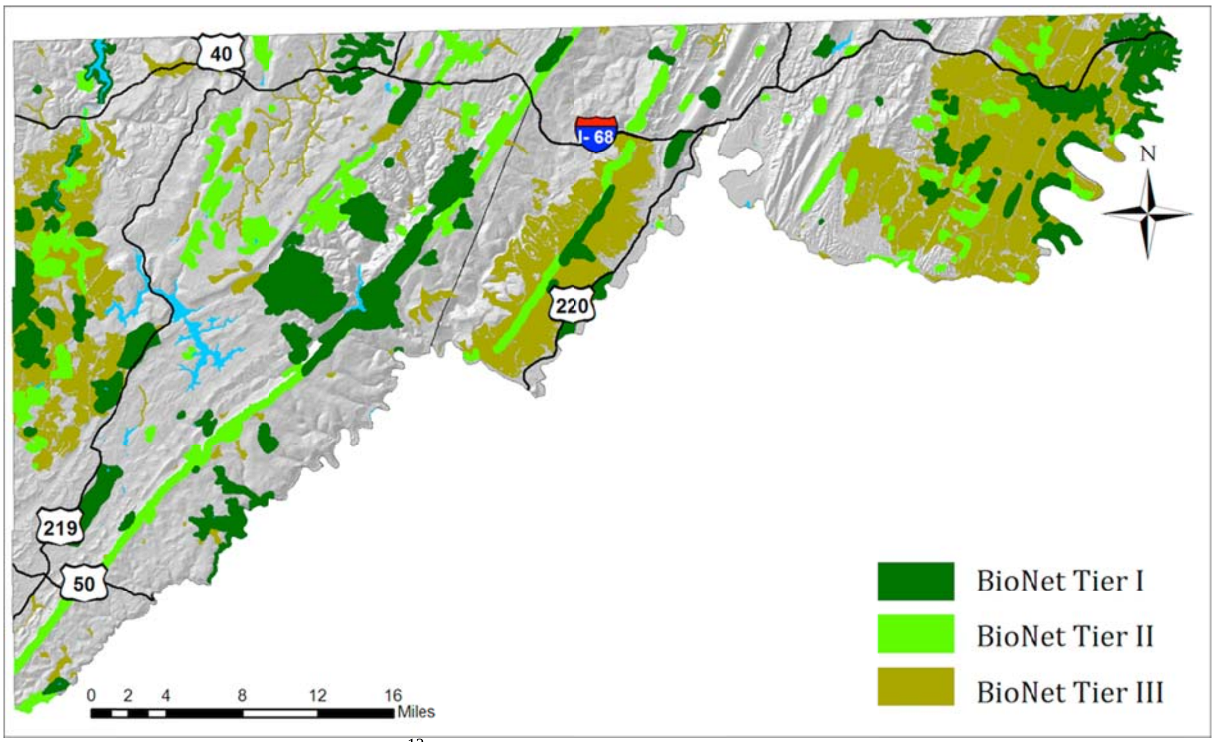

Figure 5-4. Maryland BioNet I and II[12] sites in Allegany and Garrett County with a 600 ft setback buffer. These sites represent locations that are considered irreplaceable natural areas by the state. Tier III sites (highly significant for biodiversity conservation) are also shown.

[9] http://www.caves.org/WNS/USFWS-WNS_cave_advisory_news_rls_2009-03-26_final-1.pdf.
[10] A map of the density of obligate cave dwelling species in the eastern United States can be found at: http://www.karstwaters.org/files/speciesmaps.htm
[11] Dan Feller (Maryland DNR - Wildlife and Heritage Service, Western Region Ecologist), personal communication
[12] www.dnr.maryland.gov/wildlife/Plants_Wildlife/digitaldata.asp

E. Noise and light

Noise and light pollution associated with unconventional gas development have not been studied in depth, but increasing evidence suggests that these factors have significant effects on wild animals (Beier 2005, Pijanowski et al. 2011). More research on the topic is needed, particularly with respect to noise. Noise pollution can affect wildlife in at least two ways: (1) disruption of communication by masking acoustic signals (primarily an issue for birds, but may also affect amphibians and terrestrial mammals); and (2) reductions in abundance, distribution and density of species due to avoidance behavior (Patricelli and Blickley 2006, Barber et al. 2009). In a study of gas well operations in northwestern New Mexico, noise amplitude was amplified over baseline amplitudes up to distances of 3000 ft from a compressor (Francis et al. 2010). Nest occupancy was depressed for bird species within this affected area by an average of 5%. In a study of Wyoming sage-grouse, natural gas drilling and road noises were recorded and played at 70 dB(f) in front of leks[13] (Blickley et al. 2012). This sound pressure level is similar to what is measured 1300 ft from drilling rigs and main access roads in that landscape. After three years of study, intermittent noise from roads decreased male attendance at the leks by 73% relative to paired controls. Drilling noise decreased attendance by 29%. Another study on mule deer indicated significant decreases in populations in areas within close proximity to well pads due to avoidance behavior (Francis et al. 2010).

The use of sound barrier walls around compressors can reduce the area affected by noise by up to 70% and maintain occupancy and nest success rates at levels close to those expected in a landscape without compressor noise (Francis et al. 2010). New York State (NYSDEC 2011) and API (API 2011) have established techniques for evaluating and mitigating noise impacts of gas operations. Following these guidance documents and consistent with Chapter 9 we recommend that Maryland require as part of the permitting process: (1) maintaining a maximum distance between well pads and BioNet irreplaceable natural areas to reduce noise effects on these sensitive lands; (2) constructing artificial sound barriers where natural noise attenuation would be inadequate; (3) equipping all motors and engines with appropriate mufflers; and (4) avoiding construction and drilling operations during sensitive migrating and mating seasons.

All bats and many other mammals, amphibians, and birds are nocturnal. When subjected to artificial lighting at night, documented animal responses include altered forage and mating behavior that, depending on the species and circumstances, can lead to changes in survival and fecundity (e.g., Beier 2005). Bats, for example, use their limited vision to exploit low levels of light as they leave a roost and to avoid obstacles [such as the capture nets used by biologists that study bats (Wang et al. 2004)]. Notably, bats are known to avoid disorienting bright light. Bats are farsighted, suggesting they use light more often when it is further away and dim, and switch to echolocation for objects that are closer. When migrating, bats will use vision rather than echolocation, which helps to explain why they are known to fly into wind turbines (Johnson et al. 2003). With song birds, artificial lighting has been shown to shift singing to earlier morning hours, alter mating success, and result in an earlier start of egg laying in spring (Miller 2006, Kempenaers et al. 2010). Artificial lighting alters foraging, reproductive, and defensive

[13] A lek is a gathering of males, of certain animal species, for the purposes of competitive mating display.

behaviors in amphibian species (Andrews et al. 2008). For example, frog calls are reduced under artificial lighting, which can reduce mating success and thus affect population dynamics (Baker and Richardson 2006). Artificial lighting near aquatic habitat can also become an attractive nuisance, attracting insects that subsequently die before finding new habitat.

There are two sources of light that are commonly found at drill pad sites during MSGD: (1) artificial lighting, used to illuminate the site or transportation routes to and from, or between drill pad sites, and (2) flaring of unwanted or waste gas during well completion. Although the impact of artificial light in rural settings such as western Maryland is fairly well documented, relatively little has been recommended as BMPs by the various states for unconventional gas development. Some states have suggested flaring is the most egregious source of light. For example, Pennsylvania requires gas operators to provide a minimum of 10 days notice to the Forest District Manager when flaring activities are anticipated, but this requirement only pertains to Dark Sky Areas. The Forest District Manager is required to coordinate with drilling operators to reduce conflicts during special events on state lands that require dark skies (PADCNR 2011). Proposed rules in Colorado and BMPs recommended by API also mention light pollution (API 2011), but only suggest considering light as a motivation for increasing setbacks from residences. Proposed rules in New York are the most protective of wildlife, requiring lighting used at well pads to shine downward during bird migration periods (April 1–June 1 and August 15–October 15)(NYSDEC 2011).

Additional best management practices available to Maryland include requiring: (1) diffuse downward pointing lighting at all times; (2) the use of low-pressure sodium lamps (most energy efficient) instead of high-pressure sodium or mercury lamps; (3) the use of UV filters; (4) reduced lighting to only locations and intensity needed; and (5) using green light rather than red or blue where possible. Green light and UV filtered light has been found to be less disorienting to migrating birds than is red or blue light (Wiltschko et al. 1993, Poot et al. 2008). Limiting the height of lighting columns (e.g., to a height less than 8 m) and directing light downward reduces the ecological impact of the light (Fure 2006). In some circumstances, outfitting sensors to lights that are activated when light is needed could be an effective means of reducing light levels on average. Flaring during the completion process should be minimized or eliminated, which will be required by USEPA starting in 2015 (Chapter 1). When we visited a drill pad site in West Virginia operated by Chesapeake Energy, we noted that lighting was mounted appropriately low and was covered with diffusing fabric, presumably to reduce glare and shadows. Each lamp was “capped” with a downward-reflecting shield, which might be effective at reducing light pollution of dark skies (Figure 5-5). We did not see these lamps in

Figure 5-5. The authors observed lamps at this well pad in Brooke County, WV (operated by Chesapeake Energy) that appeared to be consistent with recommended lighting BMPs. Photo by A.J. Elmore.

operation, but they appeared to be consistent with the BMPs recommended by the states and by API.

F. Construction of roads and pipelines

Roads, pipelines, and other built linear features can have significant effects on even a largely forested landscape such as western Maryland. Fragmentation created by infrastructure development is a major threat to biodiversity and a primary concern resulting from MSGD (e.g., Alkemade et al. 2009). A recent meta-analysis of 49 studies on 234 species of birds and mammals found the effect of infrastructure to extend up to 1 km for bird populations, and 5 km for mammal populations (Francis et al. 2010). These impacts include: mortality from road construction, mortality from collision with vehicles, modification of animal behavior, alteration of the physical environment, alteration of the chemical environment, spread of exotics, and increased use of areas by humans (Trombulak and Frissell 2000). Threats to wildlife can be elevated by increased traffic on roads that have historically received little activity (Gibbs and Shriver 2005) and by genetic isolation of species with poor dispersal abilities (Keller et al. 2004). These studies illustrate the importance to terrestrial wildlife of minimizing new infrastructure development in lands that are currently relatively undisturbed. The potential impacts of road noise have been discussed above, and the consequences of increased impervious surface on aquatic resources are addressed in Chapter 6 of this report.

A relatively sparse network of roads currently fragments the Marcellus Shale region of western Maryland, which translates to significantly lower cumulative ecological risk than the much denser road network of the eastern part of the state. In general, regions in which more than 60% of the total land area is within 1,250 ft of a road are at elevated risk of having those roads impact ecosystem condition (Riitters and Wickham 2003). The median distance to roads in western Maryland is currently 630 ft (Figure 5-6). The contribution of new roads to forest fragmentation is greatest in largely forested areas such as the Appalachian Mountains (Riitters and Wickham 2003). An intensive network of new secondary roads and pipelines can be anticipated with MSGD. A study of the landscape changes due to natural gas extraction in the Marcellus shale region of Pennsylvania found an increase in forest edge of 380 miles in Bradford County and 721 miles in Washington County between 2004 and 2010, with the largest amount (55%) attributable to road and pipeline construction (Slonecker et al. 2012). For both counties, pipeline construction was the major contributor to overall forest loss, increase in patchiness, and decrease in mean forest patch size.

We recommend minimizing the amount and impact of new road and pipeline construction as much as practicable by following the guidance proposed by New York State: (1) limiting the linear distance of new roads through strategic siting of operations; and (2) co-locating project infrastructure with current roads, power lines, and pipelines (NYSDEC 2011). Centralization and co-location of infrastructure also offset air pollution by decreasing truck traffic (PADCNR 2011). As the extent of road effects is thought to be at least as far-reaching as drilling operations, it would be most protective if all setbacks described in this chapter be applied to road construction as well as well-pad development: 300 ft from riparian areas, 600 ft from irreplaceable natural areas and wildlands, and 1,000 ft from caves. All new infrastructure construction should consolidate facilities and pipeline rights-of-way[14]. When practical, new construction could utilize pre-existing disturbance and be scheduled using seasonal restrictions to avoid migratory and mating seasons (e.g., peak breeding season approximately May 15-July 15) (NYSDEC 2011).

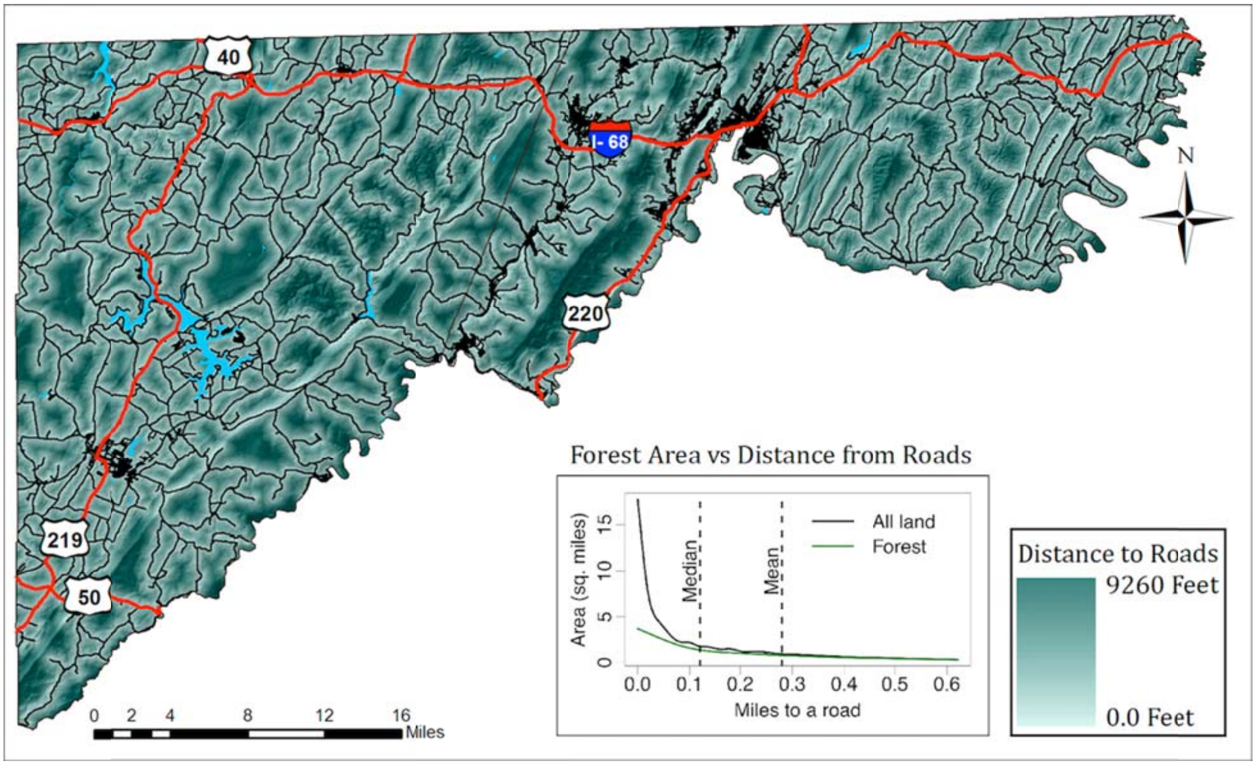

Figure 5-6. Map of the road network of Garrett and Allegany County showing distance to the closest road for each 30-m grid cell. Locations close to roads would be preferred for siting well pads to reduce the amount of new infrastructure and associated disturbance required. The histogram (inset) provides the distribution of landscape area and forested landscape area at specified distances from roads (for all land only, the median = 0.12 miles and mean = 0.28 miles are shown).

G. Invasive plants and wildlife

Gas development can disrupt native plant communities, providing opportunities for invasions of exotic species. Most states with active shale gas operations have current or proposed recommended practices for pre-construction inventory, prevention, management, control, and monitoring of invasive species. New York State has proposed baseline surveys and the development of a comprehensive management plan for all taxa of invasive species in the state that emphasizes early detection and rapid response (NYSDEC 2011). Pennsylvania DCNR has outlined BMPs for state forests that includes pre-construction inventories, cleaning procedures for equipment, annual surveys, and species specific control measures for post-disturbance infestations (PADCNR 2011). Colorado requires all heavy equipment, hand tools, boots and

[14] University of Colorado. Intermountain Oil and Gas BMP Project: http://www.oilandgasbmps.org/

other equipment to be disinfected prior to moving the equipment for use at a new site[15]. Additional BMPs advocated by Pennsylvania DCNR include (PADCNR 2011):

- *A pre-construction inventory should be performed within the anticipated areas of disturbance to determine the appropriate prevention methods, predict control needs and assess its level of responsibility for management.*
- *Soil disturbance should be minimized to decrease introduction. Consider co-location within previously disturbed areas and/or alternative construction methods.*
- *The operator should clean equipment in an appropriate manner prior to bringing equipment into un-invaded areas or ecologically sensitive areas.*
- *It is recommended that the operator use weed-free seed, soil, gravel, and mulch. Failure to use of weed-free material increases the potential to introduce invasive plant species and requires stringent monitoring.*
- *Pre-treat invasive plant species infestations that reproduce prolifically from rhizome/root segments prior to disturbance. Pre-treatment may limit the spread of the invasive plant infestations upon completion of disturbance activities.*
- *Disturbed areas should be surveyed annually at the appropriate time of year to detect early infestations.*
- *Management and control of post-disturbance infestations of invasive plant populations should be species specific. In some situations, it may be best to wait another growing season to assess the spread before moving forward with management techniques.*

We recommend that permitting require specific plans for: (1) flora and fauna inventory surveys of sites prior to operations; (2) interim reclamation following construction and drilling to reduce opportunities for invasion; (3) annual monitoring and treatment of new invasive plant populations as long as the lease is active; and (4) post-activity restoration to pre-treatment community structure and composition using seed that is certified free of noxious weeds.

H. Reclamation

Reclamation and site decommissioning were discussed in Chapter 4 in the context of water and water quality management, but reclamation is also important in terms of providing forage and cover habitat for terrestrial species and minimizing opportunities for non-native plant invasions. Consistent with our recommendations in Chapter 4, reclamation planning should be conducted in two separate phases. Within an established period of time following the construction and drilling phases of development and bringing a well into production, any portion of a well pad site that is not needed for gas production should be revegetated. New York and Pennsylvania provide specific recommendations for this interim phase including creating soft edges around new clearings by maintaining current understory shrubbery or planting native plants (NYSDEC 2011); revegetation should avoid wet seasons and wet periods outside of wet seasons to minimize impacts on soils, water, and vegetation (PADCNR 2011). Monitoring of native and invasive species could occur on-site throughout the length of the lease. For example, proposed protocols in New York call for monitoring of forest interior or grassland birds during the construction phase of the project and for a minimum of two years following well completion (NYSDEC 2011). A second phase of terrestrial habitat reclamation occurs after the wells have been plugged and gas production activities have ceased at a site. Permanent site restoration should remove the built infrastructure, restore the disturbed soil, re-contour the site, and provide

[15] Ibid.

a permanent vegetative cover. Clear objectives for final site restoration should be specified as part of the permitting process. Options include reverting the site back to its original land cover or restoring the landscape to its native condition, which in this area of the country is forest cover. In all cases, species planted should be in their natural geographic range and local stock should be preferred (PADCNR 2011).

I. Key recommendations

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.

- 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.
- 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.
- 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).

5-B Allow for freshwater impoundments only. Impoundments should not be used for flowback or produced wastewater.

- 5-B.1 Require watertight, closed metal tanks with secondary containment for all storage of chemicals and wastewater.
- 5-B.2 Include runoff and spill prevention, response, and remediation plans as part of the permitting process

5-C Establish and enforce setbacks to conserve terrestrial and aquatic biodiversity.

- 5-C.1 Enforce 300 ft minimum setbacks from all floodplains, wetlands, seeps, vernal pools, streams, or other surface water bodies.
- 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.
- 5-C.3 Enforce 1,000 ft setback from any cave to reduce stress to bats and other obligate subterranean species.

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.

- 5-D.1 Avoid construction and drilling operations during sensitive migratory and mating seasons.

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.

5-E.1 When drill pads are located within 1,000ft of aquatic habitat, vegetative screens and additional lighting restrictions could be required to reduce light pollution into these sensitive areas.

5-F Co-locate linear infrastructure as practicable with current roads, pipelines and power lines to avoid new disturbance.

5-F.1 Avoid stream crossings and any disturbances to wetlands and riparian habitat.

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.

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.

5-H Develop a two-phased reclamation strategy comprised of (1) interim reclamation following construction and drilling to reduce opportunities for invasion and (2) post-activity restoration using species native to the geographic range and seed that is certified free of noxious weeds.

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Appendix 5A

Rare, Threatened, and Endangered Species with Current or Recent Populations in Maryland's Marcellus Shale Region (within or west of Town Creek, Allegany County)

Scientific Name	Common Name	Global Rank	State Rank	State Status	US Status
ANIMALS					
Accipiter gentilis	Northern Goshawk	G5	S1B	E*	
Accipiter striatus	Sharp-shinned Hawk	G5	S1S2B		
Aeshna canadensis	Canada Darner	G5	S2		
Aeshna tuberculifera	Black-tipped Darner	G4	S2		
Amblyscirtes hegon	Pepper and Salt Skipper	G4	S2	I	
Ammodramus henslowii	Henslow's Sparrow	G4	S1S2B	T	
Aneides aeneus	Green Salamander	G3G4	S2	E	
Apalone spinifera*	Eastern Spiny Softshell	G5	S1	I	
Arrhopalites sp. 1*	Crabtree Cave Springtail	GNR	SU		
Bartramia longicauda	Upland Sandpiper	G5	S1B	E	
Boyeria grafiana	Ocellated Darner	G5	S1		
Caecidotea franzi	Franz's Cave Isopod	G2G4	S1	E	
Caecidotea sp. 1	An Isopod	G1	S1		
Caecidotea sp. 6	An Isopod	GNR	S2		
Calephelis borealis	Northern Metalmark	G3G4	S2	T	
Callophrys irus	Frosted Elfin	G3	S1	E	
Calopteryx amata	Superb Jewelwing	G4	S1S2	T	
Chlosyne harrisii	Harris's Checkerspot	G4	S2	T	
Cicindela patruela	Northern Barrens Tiger Beetle	G3	S1	E	
Circus cyaneus	Northern Harrier	G5	S2B		
Cistothorus platensis	Sedge Wren	G5	S1B	E	
Colias interior	Pink-edged Sulphur	G5	S1		
Cordulegaster obliqua	Arrowhead Spiketail	G4	S2		
Cryptobranchus alleganiensis	Eastern Hellbender	G3G4	S1	E	
Dactylocythere scotos	An Entocytherid Ostracod	GNR	S1		
Dendroica fusca	Blackburnian Warbler	G5	S1S2B	T	
Discus catskillensis	Angular Disc	G5	S1		
Empidonax alnorum	Alder Flycatcher	G5	S2B	I	
Enallagma annexum	Northern Bluet	G5	S1		
Enallagma antennatum	Rainbow Bluet	G5	S1		
Erethizon dorsatum	Porcupine	G5	S1S2	I	
Erora laeta	Early Hairstreak	GU	S1	E	
Euchloe olympia	Olympia Marble	G4G5	S2	I	
Eumeces anthracinus	Northern Coal Skink	G5	S1	E	
Euphyes bimacula	Two-spotted Skipper	G4	S1	E	
Fontigens bottimeri	Appalachian Spring Snail	G2	S2		
Glaucopsyche lygdamus	Silvery Blue	G5	S2	I	
Gomphus rogersi	Sable Clubtail	G4	S2	I	
Hendersonia occulta	Cherrydrop Snail (Cherrystone Drop)	G4	S2	I	
Junco hyemalis	Dark-eyed Junco	G5	S2B		
Lanthus parvulus	Northern Pygmy Clubtail	G4	S2		

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Lanthus vernalis	Southern Pygmy Clubtail	G4	S2		
Leucorrhinia glacialis	Crimson-ringed Whiteface	G5	S1		
Leucorrhinia hudsonica	Hudsonian Whiteface	G5	S1		
Lophodytes cucullatus	Hooded Merganser	G5	S1B		
Lycaena epixanthe	Bog Copper	G4G5	S1	E	
Microtus chrotorrhinus carolinensis	Southern Rock Vole	G4T3	S1	E	
Mustela nivalis	Least Weasel	G5	S2S3	I	
Myotis leibii	Eastern Small-footed Bat	G3	S1	E	
Myotis sodalis	Indiana Bat	G2	S1	E	LE
Neotoma magister	Allegheny Woodrat	G3G4	S1	E	
Noturus flavus	Stonecat	G5	S1	E	
Nymphalis vaualbum	Compton Tortoiseshell	G5	S1B	E	
Oporornis philadelphia	Mourning Warbler	G5	S1B	E	
Papilio cresphontes	Giant Swallowtail	G5	S2	I	
Planaria dactyligera	A Planarian	GNR	S2		
Plethodon wehrlei	Wehrle's Salamander	G4	S2	I	
Porrhomma cavernicola	Appalachian Cave Spider	G5	S2		
Porzana carolina	Sora	G5	S1B		
Procotyla typhlops*	A Planarian	G1G2	S1	E	
Pseudacris brachyphona	Mountain Chorus Frog	G5	S1	E	
Pseudanophthalmus sp. 15	Maryland Cave Beetle	G1	S1		
Pyrgus wyandot	Grizzled Skipper	G1G2Q	S1	E	
Regulus satrapa	Golden-crowned Kinglet	G5	S2B		
Rhionaeschna mutata	Spring Blue Darner	G4	S1	E	
Sitta canadensis	Red-breasted Nuthatch	G5	S1B		
Somatochlora elongata	Ski-tailed Emerald	G5	S2		
Sorex dispar	Long-tailed Shrew	G4	S2	I	
Sorex fumeus	Smoky Shrew	G5	S2S3	I	
Sorex palustris punctulatus	Southern Water Shrew	G5T3	S1	E	
Speyeria atlantis	Atlantis Fritillary	G5	S1	T	
Sphalloplana sp. 1	A Planarian	GNR	S1S2		
Strophitus undulatus	Creeper	G5	S2	I	
Stygobromus allegheniensis	Allegheny Cave Amphipod	G5	S2S3	I	
Stygobromus emarginatus*	Greenbrier Cave Amphipod	G3	S1	E	
Stygobromus franzi	Franz's Cave Amphipod	G3G4	S2S3	I	
Stygobromus sp. 5	Barrelville Amphipod	GNR	S1		
Stygobromus sp. 6*	Devil's Hole Cave Amphipod	GNR	S1		
Stylurus scudderi	Zebra Clubtail	G4	S1		
Sylvilagus obscurus	Appalachian Cottontail	G4	S1	I	
Triodopsis picea	Spruce Knob Threetooth	G3	S1		
Troglodytes troglodytes	Winter Wren	G5	S2B		
Vermivora ruficapilla	Nashville Warbler	G5	S1S2B	I	
Virginia valeriae pulchra	Mountain Earthsnake	G5T3T4	S1S2	E	
Webbhelix multilineata*	Striped Whitelip	G5	S1		
PLANTS					
Abies balsamea	Balsam Fir	G5	S1		
Aconitum uncinatum	Blue Monkshood	G4	S1	E	
Actaea podocarpa	American Bugbane	G4	S2		

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Adlumia fungosa	Climbing Fumitory	G4	S2	T
Amelanchier humilis	Running Serviceberry	G5	S1	T
Amelanchier sanguinea	Round-leaf Serviceberry	G5	S1	E
Amelanchier stolonifera	Running Juneberry	G5	S2	
Angelica triquinata	Filmy Angelica	G4	S1	E
Aralia hispida	Bristly Sarsaparilla	G5	S1	E
Aristolochia macrophylla	Pipevine	G5	S1	T
Asplenium pinnatifidum	Lobed Spleenwort	G4	S1	E
Botrychium oneidense	Blunt-lobe Grape-fern	G4Q	S1	E
Bouteloua curtipendula	Side-oats Grama	G5	S2	
Bromus latiglumis	Broad-glumed Brome	G5	S1	E
Calla palustris	Wild Calla	G5	S1	E
Calystegia spithamaea	Low Bindweed	G4G5	S2	
Campanula rotundifolia	Harebell	G5	S2	
Carex aestivalis	Summer Sedge	G4	S1	E
Carex appalachica	Appalachian Sedge	G4	S1?	
Carex buxbaumii	Buxbaum's Sedge	G5	S2	T
Carex careyana	Carey's Sedge	G4G5	S1	E
Carex diandra*	Lesser Panicled Sedge	G5	S1	E
Carex eburnea*	Ebony Sedge	G5	S1	E
Carex haydenii	Cloud Sedge	G5	S1	E
Carex lacustris	Lake-bank Sedge	G5	S2	
Carex pedunculata	Long-stalked Sedge	G5	S1	E
Carex plantaginea	Plantain-leaved Sedge	G5	S1?	
Carex tuckermanii	Tuckerman Sedge	G4	S1	E
Castilleja coccinea	Indian Paintbrush	G5	S1	E
Chenopodium gigantospermum	Maple-leaved Goosefoot	G5	S1	E
Chenopodium standleyanum	Standley's Goosefoot	G5	S1	E
Clematis occidentalis	Purple Clematis	G5	S1	E
Clintonia alleghaniensis	Harned's Swamp Clintonia	G1Q	S1	
Clintonia borealis	Yellow Clintonia	G5	S2	T
Coptis trifolia	Goldthread	G5	S1	E
Corallorhiza trifida	Early Coralroot	G5	S1	E
Cornus canadensis*	Bunchberry	G5	S1	E
Cornus rugosa	Round-leaved Dogwood	G5	S1	E
Cymophyllus fraserianus	Fraser's Sedge	G4	S1	E
Delphinium exaltatum	Tall Larkspur	G3	S1	E
Dicentra eximia	Wild Bleeding-heart	G4	S2	T
Diplazium pycnocarpon	Glade Fern	G5	S2	T
Dirca palustris	Leatherwood	G4	S2	T
Dryopteris campyloptera	Mountain Wood-fern	G5	S1	E
Epilobium leptophyllum	Linear-leaved Willowherb	G5	S2S3	
Epilobium strictum	Downy Willowherb	G5?	S1	E
Equisetum sylvaticum	Wood Horsetail	G5	S1	E
Erigeron pulchellus var. brauniae	Lucy Braun's Robin Plantain	G5T4	S1	
Erythronium albidum	White Trout Lily	G5	S2	T
Eupatorium maculatum	Spotted Joe-pye-weed	G5	SU	X
Eurybia radula	Rough-leaved Aster	G5	S1	E
Gaultheria hispidula	Creeping Snowberry	G5	S1	E
Gentiana andrewsii	Fringe-tip Closed Gentian	G5?	S2	T

Gentianella quinquefolia	Stiff Gentian	G5	S1	E
Geum aleppicum	Yellow Avens	G5	S1	E
Glyceria grandis	American Mannagrass	G5	S1	E
Gymnocarpium dryopteris	Oak Fern	G5	S1	E
Hasteola suaveolens	Sweet-scented Indian-plantain	G4	S1	E
Helianthus laevigatus*	Smooth Sunflower	G4	S1	E
Juglans cinerea	Butternut	G4	S2S3	
Juncus articulatus	Jointed Rush	G5	S1	
Juncus brevicaudatus	Narrow-panicled Rush	G5	S2	
Larix laricina	American Larch	G5	S1	E
Listera smallii	Appalachian Twayblade	G4	S1	E
Lithospermum latifolium	American Gromwell	G4	S1	E
Lycopodiella inundata	Bog Clubmoss	G5	S2	
Matelea obliqua	Climbing Milkweed	G4?	S1	E
Matteuccia struthiopteris	Ostrich Fern	G5	S2	
Melica nitens	Three-flowered Melicgrass	G5	S2	T
Menyanthes trifoliata	Buckbean	G5	S1	E
Minuartia michauxii	Rock Sandwort	G5	S2	T
Moehringia lateriflora	Grove Sandwort	G5	S1	E
Onosmodium molle	Shaggy False-gromwell	G4G5	S1	E
Oryzopsis asperifolia	White-fruited Mountainrice	G5	S2	T
Oxydendrum arboreum*	Sourwood	G5	S1	E
Paxistima canbyi*	Canby's Mountain Lover	G2	S1	E
Pedicularis lanceolata	Swamp Lousewort	G5	S1	E
Phegopteris connectilis	Northern Beech Fern	G5	S2	
Piptatherum racemosum	Black-fruited Mountainrice	G5	S2	T
Platanthera flava	Pale Green Orchid	G4	S2	
Platanthera grandiflora	Large Purple Fringed Orchid	G5	S2	T
Platanthera peramoena	Purple Fringeless Orchid	G5	S1	T
Poa alsodes	Grove Meadow-grass	G4G5	S2	
Poa saltuensis	Drooping Bluegrass	G5	S1	E
Polemonium vanbruntiae	Jacob's-ladder	G3G4	S2	T
Polygala senega	Seneca Snakeroot	G4G5	S2	T
Prunus alleghaniensis	Alleghany Plum	G4	S2	T
Pycnanthemum virginianum	Virginia Mountain-mint	G5	S2	
Rosa blanda	Smooth Rose	G5	S1	E
Sanguisorba canadensis	Canada Burnet	G5	S2	T
Sarracenia purpurea	Northern Pitcher-plant	G5	S2	T
Schizachne purpurascens	Purple Oat	G5	S1	E
Scutellaria galericulata	Common Skullcap	G5	S1	
Scutellaria leonardii	Leonard's Skullcap	G4T4	S2	T
Sedum glaucophyllum	Cliff Stonecrop	G4	S1	E
Sida hermaphrodita	Virginia Mallow	G3	S1	E
Silene nivea	Snowy Campion	G4?	S1	E
Solidago curtisii	Curtis' Goldenrod	G4G5	S1	E
Solidago roanensis	Mountain Goldenrod	G4G5	S1?	E
Spiranthes lucida	Wide-leaved Ladys' Tresses	G5	S1	E
Spiranthes ochroleuca	Yellow Nodding Ladys' Tresses	G4	S1	E
Streptopus roseus	Rose Twisted-stalk	G5	S1S2	T
Taenidia montana	Mountain Pimpernel	G3	S2	T

Talinum teretifolium	Fameflower	G4	S1	T
Taxus canadensis	American Yew	G5	S2	T
Thelypteris simulata	Bog Fern	G4G5	S2	T
Thuja occidentalis	Arbor-vitae	G5	S1	T
Torreyochloa pallida var. fernaldii	Fernald's Mannagrass	G5T4Q	S1	
Trifolium virginicum	Kate's-mountain Clover	G3	S2S3	T
Uvularia grandiflora	Large-flowered Bellwort	G5	S1	
Vaccinium oxycoccos	Small Cranberry	G5	S2	T
Valerianella chenopodiifolia	Goose-foot Cornsalad	G5	S1	E
Viburnum lentago	Nannyberry	G5	S1	
Viola appalachiensis	Appalachian Blue Violet	G3	S2	
Woodsia ilvensis	Rusty Woodsia	G5	S1	T
Zanthoxylum americanum	Northern Prickly-ash	G5	S1	E

NOTE: Asterisked scientific names indicate species with only a single known population in Maryland. See accompanying document for an explanation of rank and status codes.

EXPLANATION OF SPECIES RANK AND STATUS CODES

Maryland Department of Natural Resources
Wildlife and Heritage Service
Natural Heritage Program

July 20, 2006

The global and state ranking system is used by all 50 state Natural Heritage Programs and numerous Conservation Data Centers in other countries in this hemisphere. Because they are assigned based upon standard criteria, the ranks can be used to assess the range-wide status of a species as well as the status within portions of the species' range. The primary criterion used to define these ranks is the number of known distinct occurrences, with consideration given to the total number of individuals at each locality. Additional factors considered include the current level of protection, the types and degree of threats, ecological vulnerability, and population trends. Global and state ranks are used in combination to set inventory, protection, and management priorities for species at the state, regional, and national levels.

GLOBAL RANK

G1 Highly globally rare. Critically imperiled globally because of extreme rarity (typically 5 or fewer estimated occurrences or very few remaining individuals or acres) or because of some factor(s) making it especially vulnerable to extinction.

G2 Globally rare. Imperiled globally because of rarity (typically 6 to 20 estimated occurrences or few remaining individuals or acres) or because of some factor(s) making it very vulnerable to extinction throughout its range.

G3 Either very rare and local throughout its range or distributed locally (even abundantly at some of its locations) in a restricted range (e.g., a single western state, a physiographic region in the East) or because of other factors making it vulnerable to extinction throughout its range; typically with 21 to 100 estimated occurrences.

G4 Apparently secure globally, although it may be quite rare in parts of its range, especially at the periphery.

G5 Demonstrably secure globally, although it may be quite rare in parts of its range, especially at the periphery.

GH No known extant occurrences (i.e., formerly part of the established biota, with the expectation that it may be rediscovered).

GU Possibly in peril range-wide, but its status is uncertain; more information is needed.

GX Believed to be extinct throughout its range (e.g., passenger pigeon) with virtually no likelihood that it will be rediscovered.

G? The species has not yet been ranked.

_Q Species containing a "Q" in the rank indicates that the taxon is of questionable or uncertain taxonomic standing (i.e., some taxonomists regard it as a full species, while others treat it at an infraspecific level).

_T Ranks containing a "T" indicate that the infraspecific taxon is being ranked differently than the full species.

STATE RANK

S1	Highly State rare. Critically imperiled in Maryland because of extreme rarity (typically 5 or fewer estimated occurrences or very few remaining individuals or acres in the State) or because of some factor(s) making it especially vulnerable to extirpation. Species with this rank are actively tracked by the Natural Heritage Program.
S2	State rare. Imperiled in Maryland because of rarity (typically 6 to 20 estimated occurrences or few remaining individuals or acres in the State) or because of some factor(s) making it vulnerable to becoming extirpated. Species with this rank are actively tracked by the Natural Heritage Program.
S3	Watch List. Rare to uncommon with the number of occurrences typically in the range of 21 to 100 in Maryland. It may have fewer occurrences but with a large number of individuals in some populations, and it may be susceptible to large-scale disturbances. Species with this rank are not actively tracked by the Natural Heritage Program.
S3.1	A species that is actively tracked by the Natural Heritage Program because of the global significance of Maryland occurrences. For instance, a G3 S3 species is globally rare to uncommon, and although it may not be currently threatened with extirpation in Maryland, its occurrences in Maryland may be critical to the long term security of the species. Therefore, its status in the State is being monitored.
S4	Apparently secure in Maryland with typically more than 100 occurrences in the State or may have fewer occurrences if they contain large numbers of individuals. It is apparently secure under present conditions, although it may be restricted to only a portion of the State.
S5	Demonstrably secure in Maryland under present conditions.
SA	Accidental or considered to be a vagrant in Maryland.
SE	Established, but not native to Maryland; it may be native elsewhere in North America.
SH	Historically known from Maryland, but not verified for an extended period (usually 20 or more years), with the expectation that it may be rediscovered.
SP	Potentially occurring in Maryland or likely to have occurred in Maryland (but without persuasive documentation).
SR	Reported from Maryland, but without persuasive documentation that would provide a basis for either accepting or rejecting the report (e.g., no voucher specimen exists).
SRF	Reported falsely (in error) from Maryland, and the error may persist in the literature.
SU	Possibly rare in Maryland, but of uncertain status for reasons including lack of historical records, low search effort, cryptic nature of the species, or concerns that the species may not be native to the State. Uncertainty spans a range of 4 or 5 ranks as defined above.
SX	Believed to be extirpated in Maryland with virtually no chance of rediscovery.
SYN	Currently considered synonymous with another taxon and, therefore, not a valid entity.
SZ	A migratory species which does not inhabit specific locations for long periods of time.
S?	The species has not yet been ranked.
-B	This species is migratory and the rank refers only to the breeding status of the species. Such a migrant may have a different rarity rank for non-breeding populations.
-N	This species is migratory and the rank refers only to the non-breeding status of the species. Such a migrant may have a different rarity rank for breeding populations.

STATE STATUS

This is the status of a species as determined by the Maryland Department of Natural Resources, in accordance with the Nongame and Endangered Species Conservation Act. Definitions for the following categories have been taken from Code of Maryland Regulations (COMAR) 08.03.08.

E Endangered; a species whose continued existence as a viable component of the State's flora or fauna is determined to be in jeopardy.

I In Need of Conservation; an animal species whose population is limited or declining in the State such that it may become threatened in the foreseeable future if current trends or conditions persist.

T Threatened; a species of flora or fauna which appears likely, within the foreseeable future, to become endangered in the State.

X Endangered Extirpated; a species that was once a viable component of the flora or fauna of the State, but for which no naturally occurring populations are known to exist in the State.

* A qualifier denoting the species is listed in a limited geographic area only.

PE Proposed Endangered; a change is COMAR is pending that would list the species as Endangered (see definition above).

PT Proposed Threatened; a change is COMAR is pending that would list the species as Threatened (see definition above).

PX Proposed Endangered Extirpated; a change is COMAR is pending that would list the species as Endangered Extirpated (see definition above).

PD Proposed to be deleted or removed from the State Threatened & Endangered Species list within COMAR.

FEDERAL STATUS

This is the status of a species as determined by the U.S. Fish and Wildlife Service's Office of Endangered Species, in accordance with the Endangered Species Act. Definitions for the following categories have been modified from 50 CRF 17.

LE Taxa listed as endangered; in danger of extinction throughout all or a significant portion of their range.

LT Taxa listed as threatened; likely to become endangered within the foreseeable future throughout all or a significant portion of their range.

PE Taxa proposed to be listed as endangered.

PT Taxa proposed to be listed as threatened.

C Candidate taxa for listing for which the Service has on file enough substantial information on biological vulnerability and threat(s) to support proposals to list them as endangered or threatened.

6. Protecting aquatic habitat, wildlife, and biodiversity[1]

Freshwater aquatic habitats (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and floodplains) are unique and critical components of watersheds, providing hotspots of biodiversity and transfers of energy, nutrients, and matter to coastal ecosystems such as Chesapeake Bay (Likens and Bormann 1974, Lowe and Likens 2005, Alexander et al. 2007, Meyer et al. 2007). Risks to aquatic habitat and wildlife from Marcellus shale gas development activities are numerous and include both direct impacts to the aquatic environment through stream dewatering, runoff generation, non-point and point source pollution, elevated thermal regimes, and indirect impacts through riparian habitat degradation. In Chapter 4 we discussed the possible adverse impacts of temporary stream dewatering on surface water supplies, but it must be emphasized that streamwater itself is a critical physical habitat characteristic that must be maintained to support aquatic biota, including species that contribute to Maryland's biotic diversity and recreational opportunities (e.g., trout). Land surface and channel erosion can greatly increase suspended sediment concentrations and turbidity levels—particularly during runoff events—resulting in decreases in water clarity and increased sedimentation of fine materials. Turbidity and sedimentation reduce water column and benthic light availability, influencing fish foraging success and the quality of substrate for habitat. Excessive sedimentation fills the pore spaces in which fish lay their eggs, adversely impacts benthic organisms such as freshwater mussels, and reduces the production of submersed aquatic vegetation (SAV). Increases in water temperature due to forest clearing, riparian vegetation disturbances, or the inadvertent discharge of previously impounded water into streams could negatively affect habitat quality and impose additional stresses on trout and other cold-water fish populations.

Conservation of aquatic habitat and wildlife requires more extensive analysis than a simple evaluation of the closest wetland or stream landscape feature. The numbers of tributaries, and their respective size and location within the stream network (Palmer et al. 2000, Benda et al. 2004) are critical to understanding population dynamics and ecosystem function (Rice et al. 2001, Rice et al. 2006). Organisms certainly vary in their susceptibility to disruptions in aquatic habitat quality, area, and connectivity due to variation in degree of habitat specificity (e.g., restricted movement within a small range of stream size) and ability or inability to travel over land between wetlands or stream reaches (Fagan 2002). While less common than dispersal within aquatic habitat, overland dispersal plays a critical role in the exchange of individuals and genetic material between distant populations (Bunn et al. 1999, Bilton 2001). Human alteration of land cover proximate to and between aquatic habitat has the potential to adversely impact the fitness, survival, and mating success of a wide variety of organisms (Oke et al. 1989, Sweeney 1993, Urban et al. 2006), leading to population declines or localized extinctions by restricting overland dispersal. As part of a comprehensive plan for conserving aquatic habitat and wildlife, Maryland should consider the larger landscape context of aquatic habitat. This should include considering: (1) how habitat is connected through physical transport and biological dispersal; and (2) cumulative impacts to watersheds from the combined effects of agriculture, urbanization, and MSGD. Because conservation of aquatic habitat, wildlife, and diversity is related to land use within the entire watershed, much of the discussion of terrestrial habitat, wildlife, and biodiversity is relevant to this

[1] Chapter co-authors: Andrew J. Elmore, Ph.D., and Keith N. Eshleman, Ph.D. (both at: Appalachian Laboratory, University of Maryland Center for Environmental Science, Frostburg, MD 21532)

chapter and many of the key recommendations (e.g., riparian buffer setback distances) were discussed in Chapter 5.

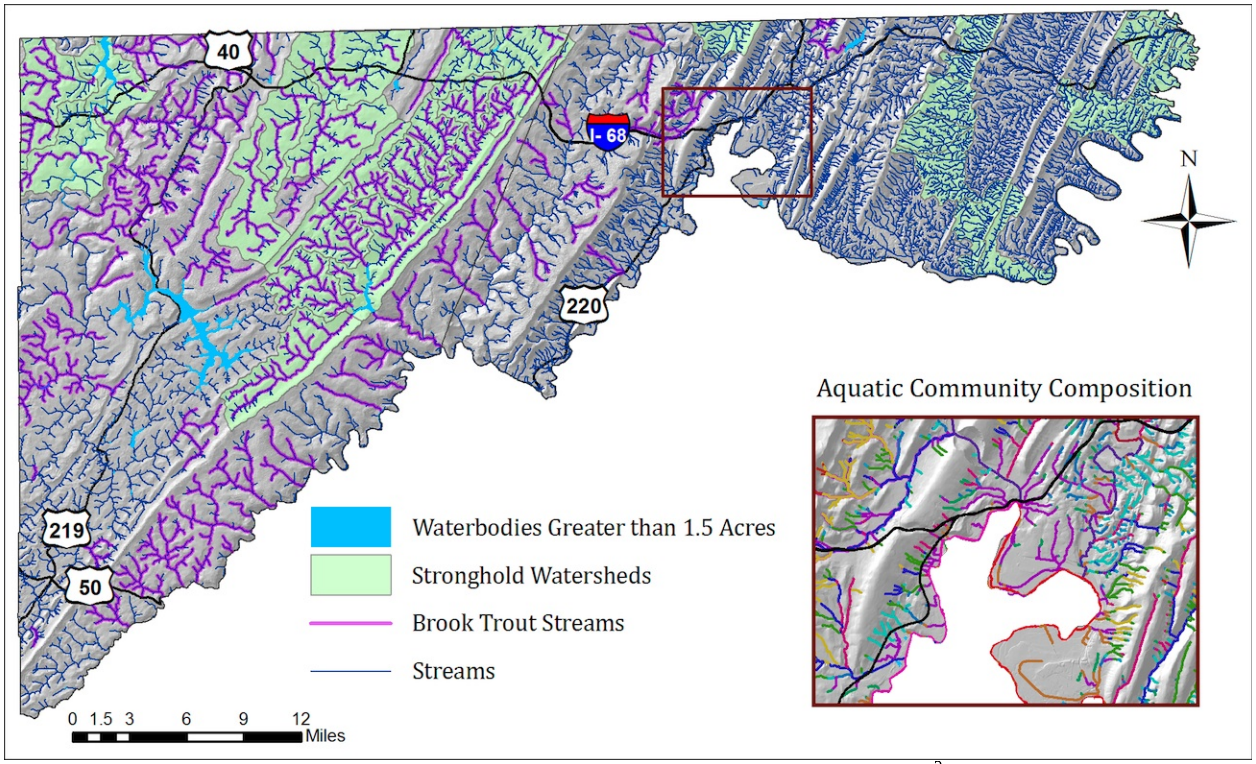

Figure 6-1. Stream density in western Maryland ranges from approximately 1.5 km/km^2 (stream length divided by watershed area) in the west to nearly 4.0 km/km^2 in the east (Julian et al. 2012, Elmore et al. in review). High stream density has the potential to complicate the siting of well pads, particularly in Stronghold watersheds (cyan) or where reproducing populations of native brook trout[2] have been identified (purple)[3]. Many streams contain unique assemblages of rare, threatened and endangered species and all streams are essential hotspots for biotic life, supporting a wide range of visitors from the terrestrial landscape. Maryland DNR as part of their Maryland Biological Stream Survey measures stream community composition annually[4]. Recent work to synthesize these data has advanced in many areas resulting in detailed maps (inset) delineating classes of stream reaches with similar community composition (represented by different colors in the map)[5].

During Marcellus shale gas development, BMPs could be employed that reduce non-point source pollution, maintain habitat of sufficient quality for rare, threatened, and endangered species as well as for species of significant commercial or recreational value (e.g., trout fisheries), and limit the introduction of non-native species. Fortunately, Maryland's aquatic environment has been under intensive study for many decades, including detailed stream survey work (MDNR 2010) and synthetic analyses aimed at establishing robust descriptions of both reference and impacted aquatic populations (Utz et al. 2009). There are many important considerations to be made when evaluating potential BMPs, but perhaps the most important is to generate and use accurate maps of wetlands and the stream network (Julian et al. 2012, Elmore et al. in review). Such data ideally

[2] Data on stronghold watersheds and brook trout were acquired from Maryland Department of Natural Resources
[3] Additional complications can arise when MSGD is proposed in Tier II streams and watersheds. We view this as a water quality concern and therefore address this topic in Chapter 4; however, clearly the available BMPs have considerable overlap.
[4] Maryland Department of Natural Resources. 2010. Retrieved from http://www.dnr.state.md.us/streams/MBSS.asp
[5] Unpublished model results, Matthew Fitzpatrick, UMCES, Appalachian Laboratory.

provide a detailed spatial representation of the aquatic resources at risk and their proximity to the proposed development. BMP selection should also be sensitive to existing conservation efforts, which are currently used in Maryland to identify watersheds and wetlands of particular value to the overall biodiversity of Maryland's aquatic habitat and to identify current threats to this biodiversity (e.g., climate change). As has been the case in Maryland's neighboring states that have active shale gas development, a variety of BMPs have been developed that cover activities in both upland and riparian environments. To best protect aquatic, wetland, and riparian habitats and wildlife in Maryland, the choice of BMPs should be based on the best available science and detailed site analyses.

A. Buffers and setbacks

A primary BMP that has been widely employed to mitigate against adverse impacts on aquatic systems is the use of a forest riparian buffer or, where forest is not present, a minimum setback distance from aquatic habitat. Upland forest buffers provide benefits to aquatic environments that can be classified as chemical, physical, or biological. The scientific basis for imposing a buffer with a specific width depends on the overall rationale for the buffer. Many favorable chemical and physical characteristics (e.g., stream nitrate concentration, sediment concentration, water temperature, benthic light availability) can be achieved by imposing a relatively small forest buffer that might not be much wider than the average canopy height (~100 ft). Consequently, a broad array of literature that focuses on aquatic habitat condition and biological diversity supports the adoption of a 100 ft buffer from aquatic habitat (see Wanger 1999 and references therein). Wider buffers are required to protect herptiles (reptiles and amphibians) that use forest riparian buffers (particularly on floodplains) for forage or dispersal. Therefore, the most appropriate forest riparian buffer width is generally larger than what would be determined if only the aquatic environment were considered. For this reason, forest riparian buffer widths described in Chapter 5 (terrestrial biodiversity conservation) generally supersede setbacks required for aquatic habitat, wildlife, and biodiversity wherever forest is present in the proposed setback.

Where forest riparian buffers are not present, either because agricultural activity or developed land cover extends all the way or most of the way to aquatic habitat, the benefit realized from setback restrictions can take different forms. Setbacks from aquatic habitat in agricultural lands can be justified wherever MSGD would produce stormwater runoff, potentially transporting sediment-laden or nutrient-rich water to streams, rivers, and wetlands. For example, productive pastures have the potential to abate the impact of such stormwater before it enters aquatic habitat. Similarly, in urban settings setbacks provide needed space for stormwater management, including retention and diversion of stormwater, thus reducing the chance that any spills and leaks would lead to contamination of aquatic habitat (see Chapter 4). Finally, in all settings (forest, agricultural, and urban), setbacks from aquatic habitat provide benefits to recreational resources. Many streams, some located close to urban and suburban communities, are used frequently for birding, fishing, boating, and swimming. To maintain the quality of these locations and reduce conflicts with these other uses, MSGD infrastructure should always be set back from aquatic habitat. Wherever possible, this setback should be forested (i.e., a riparian forest buffer) and Maryland should use MSGD as an impetus to continue it's overall efforts to increase the coverage of riparian forest buffers throughout western Maryland (e.g., mitigation plantings under Maryland's no-net-loss of forest program). However, as stated above, the lack of forest in the riparian zone should not be used as justification to reduce the setback distance.

As in many other states, no direct disturbance of any aquatic habitat for shale gas development should be permitted in Maryland. We specifically define direct disturbance as any site preparation, earth-moving, well pad construction, grading, well drilling, equipment storage, or other development activity on the land surface anywhere aquatic habitat is present (*exceptions* would be disturbances associated with any necessary access road, utility and pipeline corridor construction activities that are specifically addressed in a later section of this chapter). In addition, consistent with the most stringent setback requirements that we identified in our reviews (Lien and Manner 2010), we recommend that a minimum 300 ft aquatic habitat setback be applied in western Maryland (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). Because setbacks are intended in part to reduce the chance that spills of contaminated or sediment laden water reach aquatic habitat, the 300 ft setback should not be decreased in situations where the setback space is already cleared of forest (e.g., in agricultural settings). In all cases the intent is to protect the aquatic habitat, therefore while slope, land-cover, and soil condition likely influence the calculation of the most appropriate setback distance, a 300 ft setback should never be reduced. The 300 ft setback is consistent with, but slightly more protective, than what is being proposed or used in other states. Pennsylvania DCNR uses a 300 ft no-disturbance buffer for situations where a body of water contains threatened or endangered species or is considered either a high quality or exceptional value stream or body of water[6]. Similarly, West Virginia also enforces a 300 ft buffer for development near streams with naturally reproducing trout populations[7]. The 300 ft buffer exceeds the 100 ft requirement used on non-DCNR lands in Pennsylvania, as well as the 150 ft requirement used by New York for conventional gas development to protect permanent surface bodies of water and springs that provide domestic water (NYSDEC, 2011).

Due to the nature of horizontal drilling and the linear shape of many aquatic habitats (e.g., streams and rivers), the requirement of a 300 ft minimum setback will not significantly restrict the placement of MSGD infrastructure. Through the use of compact industrial parks for MSGD, we are confident that MSGD operators will be able to effectively access the majority of Marcellus shale gas reserves without disturbing lands within 300 ft of streams. Further, the topography of western Maryland is highly dissected, with the majority of streams located in deep, narrow ravines. Once out of these ravines, the Appalachian Plateau affords considerable area of relatively flat (<15% slope) land that, if other conditions are met, could be available for MSGD. Excluding floodplains[8], which we do not

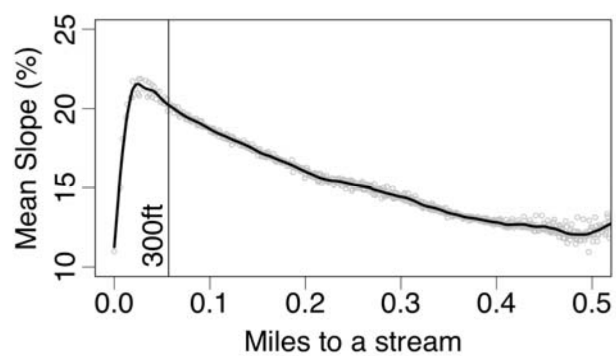

Figure 6-2. A plot of mean slope vs. distance to a stream reveals that aside from the floodplain (occurring on average within the first 100 ft of streams), the mean slope of land within 300 ft of streams is too steep for MSGD (i.e., > 15%). Note that the mean slope includes many very steep ravines, which skews the mean towards higher than expected values. In a separate calculation we found that only 40% of lands within the 300 ft stream setback were sufficiently flat to accommodate MSGD.

[6] However, PADEP enforces a 150 ft buffer for high quality streams and a 100 ft buffer for Class A trout streams outside of Pennsylvania state forests.

[7] West Virginia Horizontal Well Act; http://www.legis.state.wv.us/Bill_Status/bills_text.cfm?billdoc=hb401%20enr.htm&yr=2011&sesstype=4X&i=401.

[8] Floodplains can be adequately described by FEMA floodplain maps, which have recently been updated for western Maryland.

recommend for MSGD, only 40% of the area within 300 ft of streams exhibits a slope <15%, making it appropriate for MSGD. This statistic, combined with the fact that most of the area within 300 ft of streams is forested (and no-net-loss of forest is recommended), suggests that there are multiple interacting characteristics of lands within 300 ft of streams that make these lands unsuitable for MSGD.

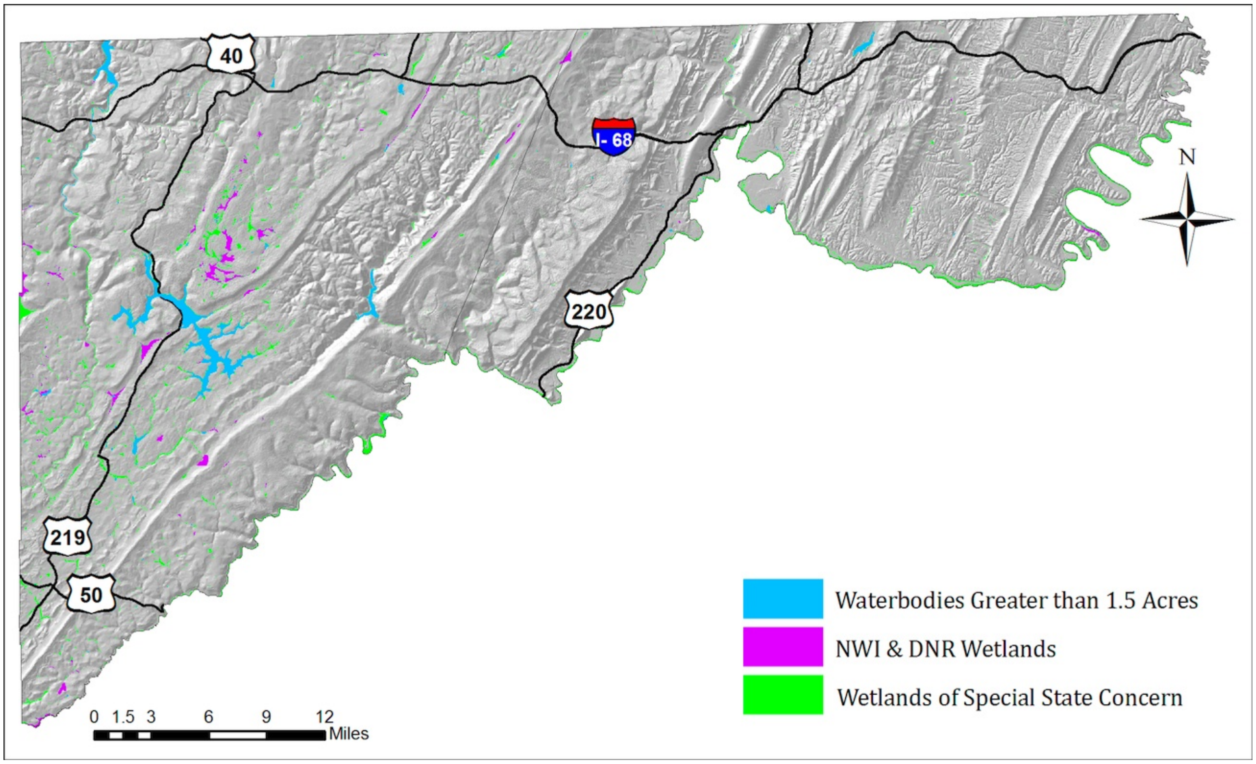

Figure 6-3. Wetlands in western Maryland are defined for regulatory purposes by the National Wetlands Inventory[9] (NWI) and by additional mapping efforts conducted by the Maryland DNR[10]. Total wetland area as defined by the union of these data sets is 20,000 acres, 7000 acres of which is made up of small wetlands with an area less than 10 acres. Certain wetlands with rare, threatened, endangered species or unique habitat receive special attention. Code of Maryland Regulations (COMAR) Title 26, Subtitle 23, Chapter 06, Sections 01 & 02 identify these Wetlands of Special State Concern (WSSC) and affords them additional protections; MDE is responsible for identifying and regulating these wetlands.

B. Special protection of high-value assets

We have identified many examples of specific BMPs that are being used by other states to provide additional protection of high-value or highly sensitive assets such as 100-year floodplains, wetlands, high quality streams, natural trout streams, and rare, threatened and endangered species beyond that provided through minimal setbacks. It has been strongly recommended that states with actual or proposed unconventional gas development undertake efforts to identify critical areas with known endangered species, unique habitats, significant migration and breeding areas for birds, mammals and aquatic organisms, and significant riparian areas (Lien and Manner 2010).

[9] U.S. Fish and Wildlife Service. 2012. National Wetlands Inventory website. U.S. Department of the Interior, Fish and Wildlife Service, Washington, D.C. http://www.fws.gov/wetlands/

[10] All DNR data for this map was acquired from Maryland Department of Natural Resources at http://dnrweb.dnr.state.md.us/gis/data/index.asp

The goal would be to develop maps that would allow identification and consideration of high value assets before initial site selection, thus reducing the chance of selecting sites that turn out to be unsuitable or unfeasible for MSGD. Pennsylvania has already developed a Pennsylvania Natural Diversity Inventory (PNDI) and associated Environmental Review Tool (ERT) that allows the public, a consultant, property owner, or project planner to perform on-line searches to identify potential impacts to threatened, endangered, special concern species and special concern resources in the Commonwealth. The ERT can now accommodate linear projects up to 10 miles in length and area projects up to 1,200 acres in size; projects that exceed these limits can be submitted for environmental review as "large projects". The County Natural Heritage Inventory (CNHI) effort in Pennsylvania is another example of a cooperative program undertaken by the Pennsylvania Natural Heritage Program (PNHP) partnership. The CNHI performs systematic studies of critical biological resources of the state on a county-by-county basis that form the basis for the PNDI permit review data.

As discussed in Chapter 1, prior to submitting a drilling application or comprehensive drilling plan for review and approval, a prospective shale gas developer could be required to consult available data on high-valued biological and water quality assets (e.g., Tier II streams and watersheds, see Chapter 4) within the western Maryland region. Similar to activities in other states, such an exercise would ideally allow a prospective operator to quickly determine the applicable BMPs governing MSGD at a particular site—thus saving considerable time and money during the planning stages of a project. To support this effort, Maryland will likely need to continue its efforts to identify high-value assets and publish in the scientific literature the methods used to make this designation. Maryland has made considerable progress in this area with the creation of its BioNet classification of irreplaceable natural areas (Chapter 5). Addressing *aquatic* biodiversity specifically, Maryland has taken the BioNet approach one step further by identifying those "stronghold watersheds" (Figure 6-1) that are: (1) the most important areas for the protection of Maryland's aquatic biodiversity; (2) where rare, threatened, or endangered freshwater fish, amphibians, reptiles, or mussel species occur in the highest densities; and (3) where special protection is deemed necessary to ensure the persistence of imperiled fauna[11]. When documented properly, such data could be effectively used to channel MSGD into watersheds or sites within watersheds where it will have the least impact on aquatic habitat and biodiversity.

The use of "stronghold watersheds" implicitly assumes that aquatic biodiversity conservation should take a "watershed approach" since some particularly sensitive species may cease to persist if even relatively small portions of these watersheds become degraded. Such is the case with remaining populations of brook trout (*Salvelinus fontinalis*), which is the only salmonid native to Maryland. Brook trout were once widely distributed throughout the central Appalachians, including western Maryland. Brook trout are sensitive to increased stream temperatures (McCormic et al. 1972, Eaton and Scheller 1996), sediment and habitat alteration, and altered stream chemistry (Leivestad 1982, Mount et al. 1988, Ingersoll et al. 1990). Altered land use is associated with disappearance of brook trout populations, with sensitivity to agriculture west of the Blue Ridge in Maryland (Utz et al. 2010) and near universal extirpation from watersheds exceeding 4% impervious surfaces (Stranko et al. 2008). Brook trout are now dramatically reduced throughout their historic range (Hudy et al. 2008). Although populations occasionally occur in highly modified watersheds, these are the exceptions rather than the rule, as is evident by

[11] http://www.streamhealth.maryland.gov/stronghold.asp

their continued disappearance from watersheds. Many of Maryland's populations currently inhabit only portions of streams, are disconnected from other streams, and are present at low abundances. Thus, many of the existing populations do not have sufficient space or numbers for long term viability (Hilderbrand and Kershner 2000, Hilderbrand 2003) and many existing populations will likely be extirpated within 20 years if the previous 20 years is a guide (Stranko et al. 2008)). Activities that decrease abundance or fragment existing populations will further increase extirpation risk in even the stronghold watersheds.

Our research into BMPs proposed or in use to protect aquatic habitat in other states suggest that stream setbacks represent the primary instrument used to provide protection of aquatic biodiversity, which in many cases leaves the door open to cumulative impacts from the linear combination of many disturbances, regardless of their distance to aquatic habitat. Increasing setbacks might offer some additional protection, but primarily for species with terrestrial life stages (see Table 5-3). Therefore, some states have included language attempting to address cumulative impacts in other ways. For example, in Colorado the responsibility is put on drilling operators to minimize land disturbance, consolidate facilities, and co-locate infrastructure whereever possible. Similarly, in Pennsylvania, operators are required to provide PADEP with a description of their efforts to avoid, minimize, or mitigate for impacts to high-valued biological assets (e.g., co-location and centralization of infrastructure, use of specialized BMPs, well pad spacing and density adjustments, working with other companies holding leases in this area to reduce cumulative impacts, etc.). In particular, there is recognition that minimizing the number of well pads through coordinated planning, consultation, and utilization of existing rights of way, can mitigate the cumulative impact on forests. Our opinion of these efforts is that, while well intended, they generally lack teeth, and will do little to address cumulative impacts in watersheds highly sensitive to even low levels of development.

In select high-value watersheds[12], Maryland should consider novel ways of establishing areal limits on surface development of all kinds (e.g., residential, commercial, wind power, unconventional shale gas, etc.) to address cumulative impacts. There is substantial scientific evidence that aquatic habitat and biodiversity respond to cumulative land disturbances or land use changes (e.g., urbanization), either linearly or non-linearly (Booth et al. 2002, Walsh et al. 2005, Petty et al. 2010, Merriam et al. 2011). While establishing fixed response thresholds for aquatic systems has proven difficult, there is considerable empirical evidence from the urban stormwater literature that cumulative surface imperviousness causes declines in aquatic biodiversity or ecological condition beginning at impervious cover well below 10% (Walsh et al. 2005, Petty et al. 2010). In Maryland's Piedmont watersheds, over half the aquatic insect species have become extinct from watersheds with 10% impervious cover (Utz et al. 2009). Among the most sensitive aquatic species is brook trout, which is almost entirely restricted to watersheds with less than 4% impervious surface (Stranko et al. 2008).

To provide an adequate margin of safety, we recommend that cumulative impervious cover (including all well pads, access roads, public roads, etc.) be maintained at less than 2% of the watershed area in select high-valued watersheds. In some cases, stronghold and Tier II watersheds (e.g., the Savage River watershed) might be excellent candidates for such additional protections, but also possibly many or all of the watersheds containing brook trout. However, additional

[12] For example, stronghold watersheds and Tier II watersheds, the second of which have anti-degradation protection under MDE's Clean Water Act regulatory authority (see Chapter 4).

analysis is warranted given the important ramifications of any approach limiting development. We believe that use of multi-well pads to access relatively large (~2 mi^2) resources of shale gas throughout western Maryland will help to maintain these recommended low levels of surface development, thus protecting aquatic systems. In addition to recommending relatively large (~2 mi^2) drilling units, Maryland could also consider employing strategic land purchases (and subsequent incorporation into the existing state forest system), as well as strategic conservation easement programs, to maintain surface imperviousness at current levels in select high-value watersheds. An overall policy of no net loss of forest (Chapters 1 and 5) will provide additional protection to aquatic diversity where other, more specific, restrictions fall short. MSGD operators should be required to follow state-of-the-art land reclamation procedures (Chapters 1 and 5) that effectively return soil permeability to pre-disturbance values before attempting to permit addition drill pads in the same watershed. Finally, it should be recognized that most stream segments in western Maryland currently have very low (<1%) cumulative impervious cover within their contributing basins (Figure 6-4), suggesting that it may be possible to site MSGD in many areas without exceeding the recommended 2% impervious cover threshold.

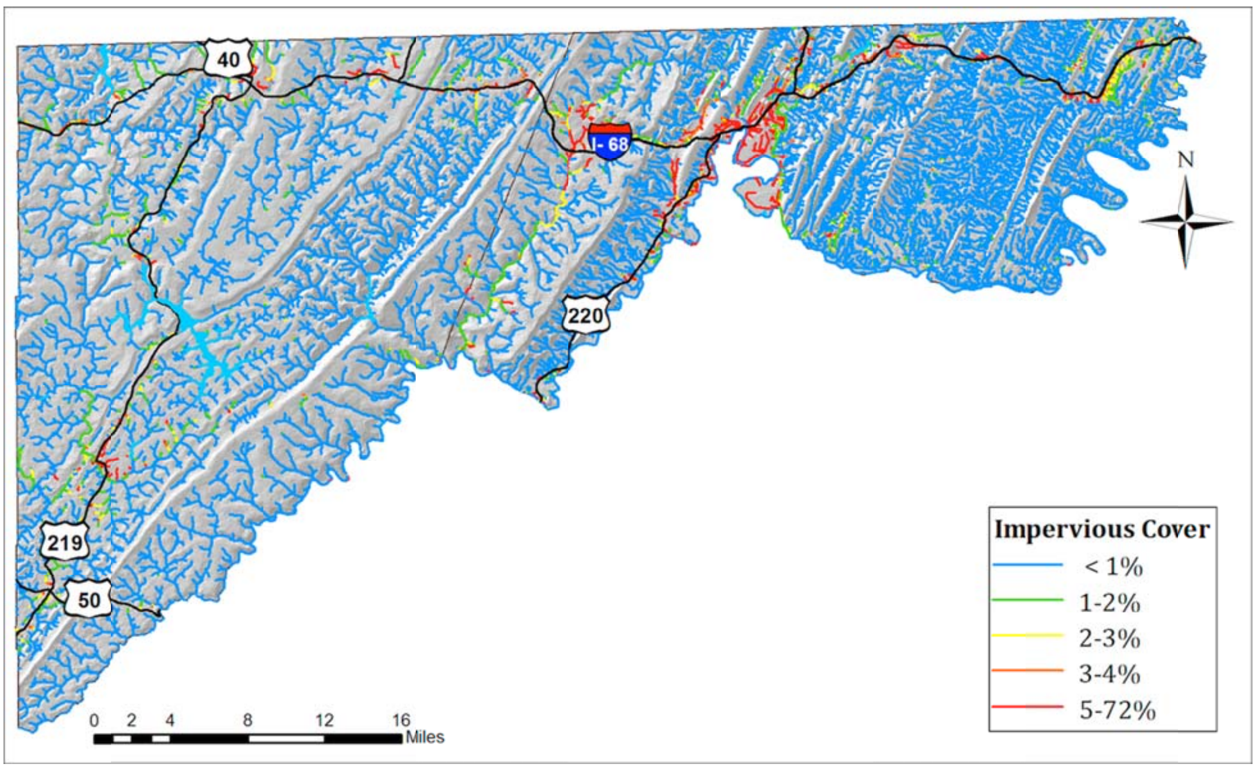

Figure 6-4. New mapping technologies (Tarboton and Baker 2008) make possible the calculation of percent impervious cover within the contributing basin of every stream segment in a landscape. The resulting map (using 2001 NLCD data on impervious cover) shows that many western Maryland watersheds have less than 1% impervious cover. This low impervious cover enables the continued existence of brook trout populations and generally elevated aquatic biodiversity relative to other areas of the state.

C. Design and construction of well pads, access roads, pits, utility corridors, and pipelines

Implementation of BMPs in design and construction of well pads, access roads, and other ancillary infrastructure associated with Marcellus shale gas development can also minimize degradation or losses of aquatic habitat and aquatic biodiversity. In addition to utilizing appropriate no-disturbance setbacks to protect aquatic habitat, proper implementation of appropriate erosion and sediment control measures (see Chapter 4) and stormwater pollution prevention techniques are important ways that aquatic habitat can be conserved.

Well pads. We have recommended "zero-discharge" well pads as a BMP for western Maryland primarily to control stormwater (and associated sediment pollution; see Chapter 4), as well as spills/leakage of chemicals from the surface to ground and surface water systems. We expect stormwater impacts to be most significant *during* well pad construction when the system is most susceptible to failure resulting from heavy rainfall events and *after* well drilling and completion activities have ended and active collection, treatment, and disposal of stormwater runoff has ceased. During well drilling when well pads are being regularly monitored, operation of passive and active stormwater collection should be able to minimize downstream impacts from the pad (i.e., this is the period in which stormwater can be actively collected in vacuum trucks, treated, disposed of, or used on site). Vacuum trucks should be kept on site throughout the period in which active stormwater collection is needed. However, only passive structural stormwater BMPs would be operational after well development is completed (or possibly during periods between individual well drilling events). Under these conditions, and without additional BMPs, the well pad would likely be functioning largely as an impervious surface, thus increasing stormwater discharge, channel erosion in small receiving streams, and downstream sedimentation. Stormwater could also become contaminated with salts or other pollutants through leaks from produced water storage tanks or liquid lines on-site, or from tanker trucks used to transport the produced water off-site. Therefore, other (passive) urban stormwater BMPs would still be needed. Since there exists the very real possibility that runoff from these pads could carry pollutants off-site, we do not recommend use of any BMPs that would promote infiltration due to the concern for groundwater pollution. The best solution for addressing both quality (i.e., suspended solids) and quantity (i.e., peak discharge) issues might be through 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 any passive phases. Regular (annual) maintenance of the pond would also be needed to ensure that the system is functioning correctly at all times. Additional water quality treatment could be obtained through operation of a constructed wetland sited downstream of the pond outlet.

As discussed in Chapter 4, these recommendations are at least in partial conflict with two of Maryland's performance standards for controlling stormwater pollution[13]: standard no. 1: site designs shall minimize the generation of stormwater and maximize pervious areas for stormwater treatment; and standard no. 2: annual groundwater recharge rates shall be maintained by promoting infiltration through the use of structural and non-structural methods. Clearly,

[13] Maryland Stormwater Design Manual , Volumes I & II (effective October 2000, revised May 2009); http://www.mde.state.md.us/programs/Water/StormwaterManagementProgram/MarylandStormwaterDesignManual/Pages/programs/waterprograms/sedimentandstormwater/stormwater_design/index.aspx

Maryland's stormwater designs originate from experience mostly with urban and suburban development and thus emphasize the use of BMPs that tend to maximize infiltration. Since these are not recommended, there will need to be some significant attention given to alternative approaches such as the ones we have identified to address these problems during periods when active stormwater management would not be a viable option.

Access roads. Wherever feasible, use of existing roads is the preferred option for facilitating transport of materials and personnel to well sites. However, we anticipate that there will be many cases where existing roads are nonexistent or inadequate and new roads will be needed. To protect aquatic habitat and minimize associated stormwater runoff, the design, routing, construction, and maintenance of any access roads to a well pad should be done in a manner that can safely support considerable heavy truck traffic, minimizes the clearing of forests, avoids steep slopes, avoids wetland and stream crossings, utilizes bridges or arched culverts for all stream crossings (leaving the stream bed relatively undisturbed), and promotes sheet flow runoff from the road surface onto surrounding soils wherever possible. Roads should not be located in or parallel to perennial or intermittent stream channels (i.e., no stream fords). Consistent with Pennsylvania DEP proposed rules, all wetland crossings should be avoided. Pennsylvania DCNR describes particularly good practices for constructing and maintaining such gravel roads to facilitate Marcellus shale gas development in Pennsylvania state forests that would also be highly applicable to western Maryland (PADCNR 2011). For road construction, Pennsylvania DCNR: (1) recommends utilizing materials and designs (e.g., crowning, elimination of ditches, etc.) that encourage sheet flow as the preferred drainage method for any new construction or upgrade of existing gravel roadways; (2) provides specific recommendations about aggregate depth, type, and placement; and (3) promotes the use of geotextiles as a way of reducing rutting and maintaining sub-base stability (PADCNR 2011). In Pennsylvania (as in western Maryland), it is typical for water to be a seasonal problem on dirt and gravel roads and 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.

Pits. We do not recommend the use of any open pits on-site for collecting and storing drilling wastes, flowback, or produced water due to concerns about surface water quality (see Chapter 4). We strongly recommend closed drilling systems in which all drilling and hydraulic fracturing fluids, chemicals, and liquid wastes are collected and stored in steel tanks that provide superior primary containment. Secondary containment can be provided by berms and liners placed strategically under tanks and areas where liquid transfers take place. Tertiary containment can be provided by construction of zero-discharge pads.

Utility corridors and pipelines. In addition to providing vehicular access to sites, road corridors can also be designed and constructed to facilitate below-ground transmission of gas, water, and AC power (if desired) to each well pad (as in the case of Pennsylvania state forests). Gathering (or feeder) pipelines provide a way of transmitting the gas to compressor stations and to larger transmission pipelines that would also need to be co-located along major roads and highways. Flexible (e.g., HDPE) pipelines could be used to transmit water to each well pad to support hydraulic fracturing operations. AC power could be used to power drilling equipment, lights, and other equipment on-site (in lieu of diesel generators). At Tiadaghton State Forest, for example, it was possible to co-locate such infrastructure within a ~35-foot wide corridor immediately adjacent to the access road. Co-location of this ancillary infrastructure along the road corridor helps minimize the extent of surface disturbance. Another viable alternative that would further minimize surface disturbance is transfer of freshwater in flexible pipes above ground (King 2012)—although this practice might be problematic in western Maryland where winter temperatures could cause these pipes to freeze and burst.

Wherever possible, any belowground transmission of gas, water, and AC power should be co-located with road infrastructure to minimize impacts on aquatic habitat. Aquatic habitat crossings, where necessary, should be accomplished with appropriate use of bridges or arched culverts to ensure free flow of water, particularly during flood stages (API 2011). The ecological effects, particularly on fish populations such as brook trout, of in-stream disturbance and semi-permanent barriers to dispersal (e.g., culverts) are well documented, and therefore should be avoided wherever possible (Burns 1972, Barton 1977, Meyer et al. 1999, Poplar-Jeffers et al. 2009). As in New York, when utility lines are to be buried beneath streams, minimum burial depths should be enforced (NYSDEC 2011). Due to documented impacts of road crossings on fish spawning success (Lachance et al. 2008), a general trout spawning substrate evaluation by DNR biologists should be required if any portion of a stream is expected to sustain a temporary or permanent blockage to fish passage. Alternatively, Maryland could ban the practice of diverting streams for any purpose and require the building of bridges or arched culverts to accomplish stream crossings. Likewise, open trenches within streams should be avoided in favor of using directional boring techniques for installation of pipelines. Directional boring is a trenchless construction technique by which an operator can drill down next to a stream, bore horizontally under a stream, and then bore up to the surface on the other side. The technique is highly advantageous over stream trenching because it leaves the stream banks and streambed intact and the need for temporarily dewatering the stream is eliminated. Risks associated with directional boring are related to the possibility of encountering unexpected subsurface voids, which have the potential to release drilling fluids and cuttings into stream waters. While such an event would be unfortunate, we believe the benefits of directional boring outweigh the risks, which can generally be mitigated for by maintaining a depth of at least 10 ft below the streambed and avoiding drilling through highly fractured substrate. In addition, efforts should be taken to avoid surface and subsurface spills or leaking of drilling fluids.

Surface impoundments. There are currently no construction standards for the kind of small (< 15 MG) freshwater impoundments that are being used throughout the state to temporarily store water prior to its use for hydraulic fracturing in Pennsylvania (Marcellus Shale Advisory Commission, 2011), although larger impoundments require dam construction and operation permits). The facility that one of us (KNE) visited in Tiadaghton State Forest was a shallow (3-4 ft deep), lined pond equipped with automated water level monitors that is capable of being continuously-monitored from either a remote or centralized office location (Figure 1-4). Adequate freeboard can be maintained by pumping out water as needed, and a series of standpipes provide a means of safely refilling the pond from water tankers. A buried pipeline enables transfer of water from the impoundment to nearby well pads. This seemed to be a particularly well designed facility that effectively isolated the stored water from the stream network (i.e., there is not an obvious mechanism other than overflow of the structure by which non-native species could be introduced into a nearby waterway). At a minimum, planning for one of these facilities should include precautionary measures to identify invasive species at water sources and avoid transporting these species to impoundments located in watersheds where these species are not present. Further, the discharge of any impounded water back into a natural water body should be prohibited to avoid increasing water temperatures in groundwater fed streams and to avoid inadvertent non-native introductions.

Surface water intake structures. Intake structures should be designed to avoid entrainment of aquatic organisms (Lien and Manner 2010) and invasive species management plans should include procedures for effectively washing intake equipment before leaving the site (see below).

D. Erosion and sediment controls

High quality headwater streams—tributary streams, intermittent streams, and spring seeps — are essential to the health of stream and river ecosystems. Headwaters, when functioning properly, help to reduce sediment in the lower reaches of the stream network. Forested buffer zones slow erosion during peak stream discharge and help maintain low stream water temperatures, a critical factor in streams that support trout and other cold-water species (e.g., Koehn and Hairston-Strang 2009, Henley et al. 2010). When forested buffers are removed or when headwater streams are directly disturbed, these channels become conduits for sediment and pollution that leads directly to larger streams and coastal receiving waters (Kaplan et al. 2008). The direct effects of sediments on fish will vary with the concentration of suspended matter, duration and timing of exposure, degree of sediment deposition, particle size distribution and type of sediment, and fish species and life stages at which the fish is exposed (Kemp et al. 2011). Known impacts from sediments in streams include: (1) reduced photosynthesis throughout the water column leading to reduced primary productivity and, therefore, reduced forage for higher trophic levels; (2) reduced periphyton attachment (a mixture of algae, cyanobacteria, heterotrophic microbes, and detritus found in most aquatic habitats) and macrophyte growth, leading to reduced animal and plant abundance, species richness, and diversity; and (3) increased sediment deposition and the loss of physical habitat (Kemp et al. 2011).

Best management practices for sediment and erosion controls are covered in detail in Chapter 4. Aside from forest buffer disturbance (which we recommend protecting against with a 300 ft riparian forest buffer), much of the risk to aquatic habitat, and headwater stream ecosystems specifically, comes from ungraded roads on steep slopes or erodible soils, and stream crossings. Research has shown that 90% of the sediment that ends up in our nation's waters from forested lands is associated with improperly designed and maintained roads (Daniels et al. 2004). Unsurfaced roads, even with only moderate levels of light vehicle traffic, produce the greatest amount of sediment per unit of rainfall. Gravel roads with a maintained driving surface of sufficient aggregate can be built to produce significantly less sediment (Sheridan and Noske 2007). In Chapter 4 and elsewhere in this report we discussed the importance of regulating road construction during MSGD and have recommended the use of gravel road design principles recommended by Pennsylvania DCNR (PADCNR 2011). Many BMPs related to road construction have proven effective, including elevating the road profile, building grade breaks and additional drainage features, removing berms, etc. (e.g., Scheetz and Bloser 2008). Other possible BMPs include the use of silt fencing, sedimentation ponds, mulches, and grass seeding, which have been shown to be effective at sediment removal during periods of little rain, but inadequate during periods of flashy flows typical of mountain streams (Hedrick et al. 2010). Therefore, using a combination of BMPs and recognizing that additional protective measures might be necessary during certain times of the year (primarily late winter and early spring), is itself a BMP for Maryland.

E. Invasive species controls

Equipment used in MSGD is often transported great distances and used in relatively pristine watersheds. In particular, water withdrawals from large rivers and reservoirs (where permitted) have the potential to introduce non-native and invasive species that can become a risk to native aquatic habitat and biodiversity. Maryland should take precautions to reduce the transmission of invasive plant and animal species by requiring an invasive species management plan of industry prior to any drilling operations. Of particular concern is the potential for harmful algal blooms (HAB), such as those produced by the non-cyanobacterial taxa, *Prymnesium parvum* (commonly known as "golden algae"), which is likely the most problematic HAB taxa in U.S. waters. *P. parvum* has caused large fish kills worldwide since as early as the 1930's, and was first suspected of fish kills in Texas in 1982 and confirmed in 1985 (Lopez et al. 2008). *P. parvum* blooms can span many miles, across entire lakes, and can even propagate hundreds of miles downriver. This algae has been implicated in the largest fish-kill associated with MSGD in PA and WV (Dunkard Creek), suggesting it is an emerging threat to freshwater systems throughout the region (Brooks et al. 2001, Renner 2009).

To protect aquatic habitat, each operator should be required to submit a site-specific invasive species management plan prior to any drilling operations. Such a plan should describe procedures to be used during any water withdrawal from a local water source. At the very minimum, equipment should be power-washed and rinsed with clean water before leaving the withdrawal site. Loose plant and soil material (potentially containing seeds, roots, or other viable plant parts) and unfiltered water, that has been removed from clothing, boots and equipment, or generated from cleaning operations, should be disposed of in appropriate containers for disposal. During power washing, wash water (including spray) should not discharge within 100 ft of any stream, existing or proposed wetland, or stormwater conveyance (e.g., ditch, storm drain, etc.). In no circumstances should water that has been transferred between watersheds or moved upstream above confluences be discharged into aquatic habitat. This would include water that has been stored in tanks or impoundments, but was not subsequently used in the drilling or completion process.

F. Key recommendations

6-A Direct disturbance of any aquatic habitat for shale gas development should not be permitted.

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.

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.

6-D The use of multi-well pads to access relatively large (~2 mi^2) resources of shale gas would enable the maintenance of reasonably low levels of surface development.

6-E Cumulative surface development (including all well pads, access roads, public roads, etc.) could be maintained at less than 2% of the watershed area in high-value watersheds.

6-F Initially, all MSGD could be excluded from areas of high-value assets (e.g., BioNet sites, stronghold watersheds, Tier II watersheds, etc.)

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).

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:

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.

6-H.2 Water withdrawal equipment should be power-washed and rinsed with clean water before leaving the withdrawal site.

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.

6-J Wherever possible, existing roads should be used in MSGD. Where new roads are required, PA DCNR recommendations could be adopted:

6-J.1 Use materials and designs (e.g., crowning, elimination of ditches, etc.) that encourage sheet flow as the preferred drainage method for any new construction or upgrade of existing gravel roadways.

6-J.2 Where stream crossings are unavoidable, use bridges or arched culverts to minimize disturbance of streambeds.

6-J.3 Promote the use of geotextiles as a way of reducing rutting and maintaining sub-base stability.

6-J.4 Open trenches within streams should be avoided in favor of using directional boring techniques.

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).

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7. Protecting public safety[1]

Modern shale gas development is an industrial activity that involves handling of very large quantities of hazardous or toxic chemicals, hydraulic fracturing fluids, and wastewaters ("brines") at outdoor sites often located in remote or rural areas. It is very common for most of these materials to be transported by trucks for considerable distances on public roads to the drilling sites. Further, like any other outdoor activities, these drilling sites are exposed to extreme weather and environmental conditions (e.g., snowstorms, rainstorms, floods, windstorms, freezing conditions, etc.) that not only make working at such sites difficult, but also elevate the risk of accidents, spills, or leakages away from a particular site. Unless such spills are prevented and/or quickly contained, surface water or groundwater contamination may result, which can expose humans or ecosystems to toxic chemicals. For this reason, New York State has concluded that shale gas well pads and all associated on-site infrastructure should be treated like other industrial facilities. The first step in protecting public safety from some of the primary hazards associated with industrial facilities is siting such facilities as far away as possible from homes, businesses, public buildings, or places with high levels of recreational activity (e.g., hiking trails, parks, picnic areas, etc.). This can be achieved through the use of setbacks and careful permitting in the vicinity of parks and other recreational resources (see Chapter 8). Secondly, employing best management practices in well construction (e.g., casing and cementing) in order to ensure wellbore integrity and isolation are important steps that must be used to control migration of hydrocarbons, brines, or hydraulic fracturing fluids into groundwater, causing pollution of underground drinking water supplies (see Chapter 3). As discussed below, security measures such as adequate signage, lighting, fencing and supervision that are appropriate to other industrial facilities should be required to ensure that shale gas development is conducted in as safe a manner as possible (NYSDEC 2011).

A. Spill prevention and emergency response

The prevention and containment of spills involving hazardous or toxic chemicals used in the completion process, hydraulic fracturing fluids, or wastewaters at a well site—or during transit to or from a well site—is a very important component of providing protection of public safety, as well as the surrounding environment. As noted previously in Chapters 1 and 4, a best practice in spill prevention and protection of public safety in general is the development of a site-specific, emergency response plan (ERP) that describes specifically in writing how a particular operator will respond to different emergencies (e.g., spills) that may occur during each phase of shale gas development at a particular site (or off-site) and across the operators' many related facilities (e.g., multiple wells and water impoundments). The procedures outlined in an ERP are intended to provide for the protection of lives (workers and the public at large), property (both on-site and off-site), and the environment, through appropriate advance planning, safety training, and coordinated deployment of company and community assets. In addition to addressing spill prevention and clean-up procedures, an ERP would also logically include procedures for protecting the public from fires, explosions, or blow-outs that could occur on a well pad[2]. While the names of such

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[2] West Virginia Horizontal Well Act. http://www.legis.state.wv.us/Bill_Status/bills_text.cfm?billdoc=hb401%20enr.htm&yr=2011&sesstype=4X&i=401

plans vary from state to state, documents describing emergency preparedness are required or proposed in all states in our review (and are advocated by API). The ERP proposed for shale gas development in New York State would have, at a minimum, the following elements (NYSDEC 2011):

- Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP
- Site name, type, location (including a copy of 7½ minute USGS map), and operator information
- Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate regulatory office), equipment, key personnel, first responders, hospitals, and evacuation plan
- Identification and evaluation of potential release, fire and explosion hazards
- Description of release, fire, and explosion prevention procedures and equipment
- Implementation plans for shut down, containment, and disposal
- Site training, exercises, drills, and meeting logs

In addition, as required by PADEP, a Prevention, Preparedness, and Contingency (PPC) Plan in Pennsylvania (similar to an ERP in New York) must include a list of all chemicals or additives used and the different wastes generated by hydraulic fracturing (and approximate quantities of each material and the method of storage on-site), as well as MSDS data, toxicological data, and waste chemical properties. A more comprehensive and standardized PPC Plan would also include: (1) assigning 9-1-1 addresses to sites to aid in emergency responses; (2) providing geographic positioning system (GPS) coordinates for access roads and well pad sites; and (3) distributing PPC Plans to the appropriate county emergency management coordinator so that emergency responders would have immediate access to MSDS information in the event of an actual emergency (Marcellus Shale Advisory Commission 2011). Another best practice related to implementation of an ERP is that inspectors be given 24-hour notice before any major operation occurs at a particular well site (i.e., cementing, hydraulic fracturing, drilling, flaring) (STRONGER 2011).

As is the policy in most states that we reviewed, an ERP should be developed in Maryland and submitted to the appropriate state regulatory authority as part of the well permit application process. The ERP could also be part of an overall site-specific safety plan developed by an operator to address the full gamut of public safety issues involving such topics as site security and off-site transportation of materials. In addition to development and implementation of an ERP, there are many other BMPs that are critical for spill prevention and containment. Most of these are primarily used for protecting water resources (both surface water and groundwater) and were discussed in more detail in Chapter 4.

Effective implementation of an ERP in the event of an actual emergency requires specialized teams of emergency responders, appropriately trained in specific well pad emergencies, public safety, and methods isolating and securing an incident site. Each county should have at least one specialized team of emergency responders available at all times to respond to an emergency. The emergency responders should leave control of well blow-outs, fires or contaminant releases to professional, operator-trained experts utilizing equipment staged in a manner to provide a timely response to emergencies. It is important that each well operator maintain all necessary equipment to respond to various types of emergencies in a satisfactory operating condition and on-site throughout the drilling and completing phases of the operation.

A county or regional task force of public/industry partners should be formed to facilitate coordination, knowledge sharing, and refinement of emergency response protocols (Marcellus Shale Advisory Commission 2011). The Commission also recommended design and implementation of a unified command system for addressing well pad incidents—with the Federal Emergency Management Agency (FEMA) ICS 300- and 400-level training programs serving as appropriate models for state use (Marcellus Shale Advisory Commission 2011).

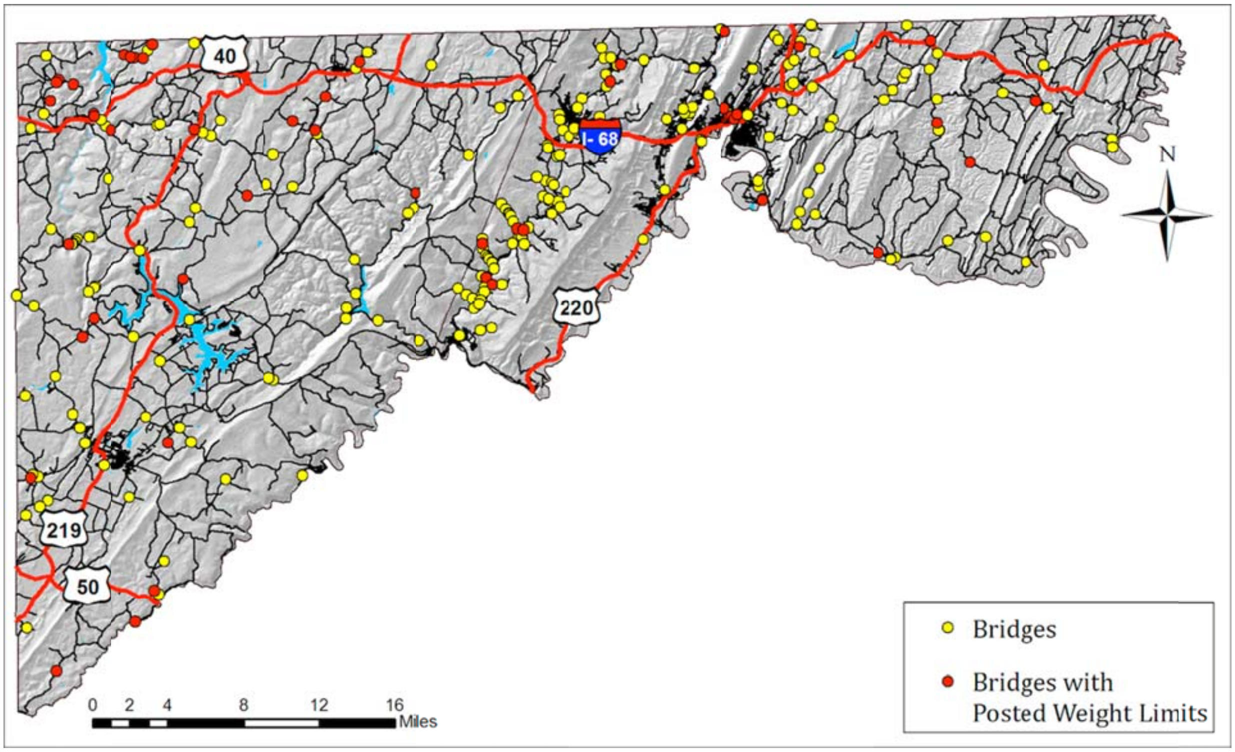

Figure 7-1. The road network in Garrett and Allegany Counties consists of primary and secondary roads and numerous bridges, some with specific weight restrictions. A detailed transportation plan would consider the existing transportation network within a formal network analysis, designed to reduce conflicts between MSGD and existing road uses. The road data shown are current as of 2011 and were acquired from the Maryland State Highway Administration (SHA)[3]. Allegany and Garrett County provided bridge locations and weight limits.

B. Site security

During site preparation, drilling, and completing of shale gas wells, the presence and operation of heavy equipment such as drill rigs and the storage and use of large quantities of chemicals present safety hazards that are comparable to those present at many other industrial facilities. For this reason, it is important that well sites and associated infrastructure be treated like other industrial sites—including securing these facilities so they can be operated in a safe manner. Once drilling and completion equipment and chemicals have been removed and wells are producing, other security measures (or a reduced level of security) may be more appropriate than during the earlier drilling and completion phases of an operation. Specific best practices to be implemented by an operator would certainly include: (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,

[3] http://www.sha.maryland.gov/Index.aspx?PageId=282

compressors, tanks, impoundments, and separators, to restrict public access; and (2) use of safety or security guards to further control access (particularly important during active drilling and completion phases of an operation). As in Ohio, duplicate keys to all locks should be provided to the regulatory agency and to local emergency responders upon request.

C. Transportation planning

Transportation planning is an important consideration in shale gas development due to the need for moving large quantities of heavy equipment, chemicals, water, and wastewater either to or from various sites distributed throughout a particular region. We discuss transportation planning in Chapter 9 in the context of protecting quality of life and aesthetics in predominantly rural western Maryland, but it should be kept in mind that transportation planning must also address risks to public safety—especially those specifically posed by frequent truck transport of materials on rural public roadways and bridges that in many cases were neither designed nor constructed for such purposes.

The natural gas industry faces significant logistical challenges associated with transporting and storing the tremendous volumes of sand, pipe, water, and other materials that are necessary to drill and complete a Marcellus shale gas well. According to the Governor's Marcellus Shale Advisory Commission (2011), the maximum distance to effectively serve a well head in Pennsylvania is 75 miles, especially due to the steep terrain found in many of Pennsylvania's drilling locations. The closer a drilling company can get to areas where it can store the vast quantities of materials required for drilling a well, the better the efficiency of the drilling operation. Railroads, already in place and operational, could provide an alternative system for effectively and efficiently receiving, storing, and trans-loading commodities to well heads in Pennsylvania and throughout the Marcellus shale region. The railroads (and rail terminals) provide an added benefit of reducing the need to develop a staging area on forest land or other vacant land within a 50- to 75-mile radius. Nevertheless, even with the benefit of rail transportation, there would still exist the need for trucks to move material and equipment from a rail terminal to the well pads (Marcellus Shale Advisory Commission 2011), so the impact of using rail transportation on truck transportation may not be that great. Further, while western Maryland is obviously home to a major CSX rail yard at Cumberland, the closest actual rail terminal to the region is in Hagerstown—60-100 miles away—perhaps too far away for railroads to play a major role in staging MSGD operations. The proximity of the Cumberland rail yard to a major interstate highway (I-68) that bisects western Maryland would seemingly make this an ideal location for an MSGD staging area, however. If Maryland decides to move ahead with MSGD, the state might consider investing public funds in new terminal facilities in western Maryland to support the activity, provide incentives for private financing, or both (as has been done in Pennsylvania through Rail Freight and Rail Transportation Assistance Programs).

With respect to truck transportation, there are obvious risks to public safety (injury, death) associated with accidents involving additional traffic onto roads and bridges, plus additional risks associated with exposure to spilled hazardous chemicals, fires, or explosions resulting from such accidents. As recommended for Pennsylvania, we believe it is reasonable to expect the appropriate state transportation authorities to calculate, evaluate, and address the major impacts of additional truck traffic on the road and highway system prior to shale gas development occurring in an undeveloped part of the state (Marcellus Shale Advisory Commission 2011). At the same time, counties and municipalities should also undertake an inventory and structural evaluation of locally-owned bridges currently exempt from federally mandated inspections (typically 8 ft to 20 ft) to ensure that these structures are capable of safely handling the additional traffic (and loads) associated with shale gas development. While this recommendation was made for Pennsylvania, we believe that the same type of analysis could and should be done for western Maryland. Where the road network or bridges are deemed inadequate for supporting the additional traffic, the road system (including inadequate bridges) should be upgraded to support such traffic prior to shale gas development occurring *or* such traffic should not be permitted on these roads. With respect to movement of heavy equipment on state highways, we also agree with the recommendation that the state should be responsible for establishing a protocol to allow for emergency transport of such equipment during off-hour periods (evenings, nights, and weekends) in cases where there is an immediate need of the equipment (Marcellus Shale Advisory Commission 2011). The protocol would be similar to how 'wide loads' are presently transported in the state of Maryland and would thus require cooperation and coordination with the state police who assume primary responsibility for the highway system.

D. Key recommendations

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.

- 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 (e.g., hiking trails, parks, picnic areas, etc.) (see Chapter 9 also).
- 7-A.2 Best management practices in well construction (e.g., casing and cementing) should be followed to ensure wellbore integrity and isolation (see Chapter 3).
- 7-A.3 Proper monitoring and pre-development assessment are important steps to limit the migration of hydrocarbons, brines, or hydraulic fracturing fluids into groundwater, causing pollution of underground drinking water supplies and to enable rapid detection in the event of migration (see Chapters 1 and 4).

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.

- 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.
- 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 (e.g., topographic and soil conditions).
- 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.

7-C Best management practices implemented to avoid emergencies should include:

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.

7-C.2 Use of safety or security guards to further control access (particularly important during active drilling and completion phases of an operation).

7-C.3 Duplicate keys to all locks should be provided to the regulatory agency and to local emergency responders.

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.

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.

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).

E. Literature cited

Marcellus Shale Advisory Commission. 2011. [Pennsylvania] Governor's Marcellus Shale Advisory Commission Report.

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STRONGER. 2011. Ohio Hydraulic Fracturing State Review. Oklahoma City, OK: State Review of Oil and Natural Gas Environmental Regulations, Inc.

8. Protecting cultural, historical, and recreational resources[1]

Western Maryland (Allegany and Garrett County) contains a plethora of cultural, historical and recreational resources. Many types of sites (e.g., national and state historic sites, heritage areas, local historic districts, state parks, wildlife management areas, wildlands, etc.) would be at risk of impairment, either through physical, visual, auditory, or olfactory degradation. In addition to their intrinsic value, some of these resources, such as historical landmarks or unique natural landscape features (lakes, waterfalls, etc.), draw considerable tourism, generating revenue for local communities and the state of Maryland. In 2011, nearly $6M in sales tax was collected through combined tourism-related sales in these two counties.[2] The local job market depends in part on tourism, accounting for over $50M in tourism-related salaries for the two-county area in 2008[3,4]. A decline in the quality or quantity of resources that attract tourism would potentially limit further economic development in this area. Disturbance associated with site preparation work, well drilling activities, truck traffic, and operation of heavy equipment—unless successfully avoided or mitigated for—could negatively impact the enjoyment of natural areas for hunting, fishing, hiking, boating, and other recreational activities. Finally, natural areas might also be impacted through inadvertent introductions of invasive species or losses of natural biological/landscape biodiversity (see Chapters 5 and 6).

A. Identification of sites

Protection of cultural, historical, and recreational resources must begin with identification of sites that would be adversely affected by Marcellus shale gas development. However, many of these resources (e.g., national and state historic properties) are virtually unknown and are typically unmapped. In cases like this, New York State requires identification of all sites that are eligible for inclusion on state and national registers of historic properties, or are included on the state inventory, to ensure that they receive special consideration, protecting them from disturbance or impairment. Many state and federal databases exist to provide such information, but the inventoried data are typically not transmitted to users in the form of a digital map. New York has actually mapped out its visually sensitive resource areas and has proposed that applicants submit a visual resource mitigation plan as part of the permit application process (NYSDEC 2011). In western Maryland, there are six listed items on the National Trust for Historic Preservation, plus 52 sites in Allegany County and 23 sites in Garrett County listed on the National Register of Historic Properties.[5] Moreover, there are literally hundreds of sites in these counties that are listed on the state inventory including historic properties, local historic districts (Cumberland and Frostburg), historic cemeteries and monuments, roadside historical markers, and a state heritage

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[2] Maryland Tourism Development Board. 2008. Annual report, available online at: http://www.visitmaryland.org/AboutMDTourism/Pages/TourismNewsAndReports.aspx.

[3] Department of Business and Economic Development. 2011. Maryland Tourism Fastfacts. Available online at: http://visitmaryland.org/AboutMDTourism/Documents/Annual_Report_2011.pdf.

[4] Additional information on the economic impact of Maryland State Parks can be found in the 2010 Maryland State Parks Economic impact & Visitor Study, accessed at the following URL on February 13, 2013: http://www.dnr.maryland.gov/publiclands/pdfs/economicimpactstudy2010.pdf

[5] http://www.mht.maryland.gov/nr/NRPickCounty.html.

area (Mountain Maryland Gateway to the West Heritage Area that includes the towns of Accident, Deer Park, Friendsville, Grantsville, Kitzmiller, Loch Lynn Heights, Mountain Lake Park, Oakland, McHenry, and Bloomington plus scenic byways that connect these towns in Garrett County) (not shown). Given the large number of sites that could be impacted in these two counties, best practice would be for operators to consult with the Maryland Historical Trust (MHT) within the Maryland Department of Planning and other county and local historic preservation offices during the planning and permit application process to ensure that no eligible or existing cultural or historical sites would be potentially disturbed or impaired by any aspect of shale gas development.

Western Maryland also contains extensive public recreational resources that will require identification and mapping, including: a national historical park, a national scenic trail, state parks, state forests, state forest trails, state wildlife management areas, natural areas, wildlands, a wild river, a national byway, and two state scenic byways. Most of these state and federal recreational resources and important natural areas are reasonably well known and mapped in Maryland. On an areal basis, state forest land (118,099 acres) is by far the largest public recreational space in the two-county region, covering 21% of the total land area. Wildlife management areas cover 17,809 acres (2.6%) and state parks cover 10,203 acres (1.5%). Confronted with a similar level of diversity in the types of resources that exist, Pennsylvania DCNR Bureau of Forestry recommends that any constraints mapping done by gas drilling companies operating in the Pennsylvania state forests should be done in close consultation with local stakeholders who typically have the best knowledge of these resources. In Maryland, 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. To facilitate this planning activity, we have provided a list of the major public recreational and natural resource areas that could be impacted by shale gas development in western Maryland (Table 8-1, Figure 8-1, Figure 8-2).

B. Setback requirements and mitigation

To avoid disturbances or impairment of major cultural and historical resources, New York State handles proposed oil and gas drilling near these sites on a case-by-case basis. A variety of mitigative actions can be required including: (1) visual screening of drilling operations; (2) setback requirements greater than minimums for private homes (100 ft) and public buildings or areas (150 ft); (3) restriction on times of operation (e.g., avoid tourist season, museum hours, whitewater release dates, opening days for hunting and fishing, etc.); and (4) landscaping reclamation requirements. In New York, many of these mitigative actions are presently added as conditions to drilling permits (NYSDEC 2011). Other mitigative BMPs that have been proposed in New York include: relocation of MSGD infrastructure found damaging by local residents or resource managers, use of camouflage or disguise to reduce the impact of MSGD infrastructure, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2011).

With respect to state forest recreational areas, Pennsylvania DCNR Bureau of Forestry requires a 300 ft. setback from any state forest picnic area, trail, road of historic value, tree plantation, overlook, vista, fire tower site, or existing right of way; this setback also affords additional protection of public safety through conflict avoidance. The Bureau of Forestry also relies on local knowledge of cultural sites, recreational trails, trailheads, high use areas, viewsheds, vistas, and high aesthetic areas during the permitting process with a goal of avoiding areas of (or providing increased setbacks from) concentrated recreational activity and developed recreational sites when permitting gas related infrastructure (PADCNR 2011). In the Pennsylvania state forests, an important criterion in site selection for drilling pads is the degree to which locations can provide natural vegetative or topographic screening (PADCNR 2011). Additionally, API recommends that setbacks be increased to take into account prevailing winds and topography; in New York, sites are assessed for their archeological importance (NYSDEC 2011).

Table 8-1. Public recreational resources in Allegany and Garrett County, Maryland.

Name of Resource	Administered by	County
Chesapeake and Ohio Canal National Historical Park	National Park Service	Allegany
Potomac Heritage National Scenic Trail	National Park Service	Allegany
Historic National Road	U.S. Dept. of Transportation	Allegany, Garrett
Dan's Mountain State Park	Maryland Dept. of Natural Resources	Allegany
Rocky Gap State Park	Maryland Dept. of Natural Resources	Allegany
Big Run State Park	Maryland Dept. of Natural Resources	Garrett
Casselman River Bridge State Park	Maryland Dept. of Natural Resources	Garrett
Deep Creek Lake State Park	Maryland Dept. of Natural Resources	Garrett
Deep Creek Lake Natural Resources Management Area	Maryland Dept. of Natural Resources	Garrett
Herrington Manor State Park	Maryland Dept. of Natural Resources	Garrett
New Germany State Park	Maryland Dept. of Natural Resources	Garrett
Swallow Falls State Park	Maryland Dept. of Natural Resources	Garrett
Youghiogheny River State Park	Maryland Dept. of Natural Resources	Garrett
Green Ridge State Forest	Maryland Dept. of Natural Resources	Allegany
Garrett State Forest	Maryland Dept. of Natural Resources	Garrett
Potomac State Forest	Maryland Dept. of Natural Resources	Garrett
Savage River State Forest	Maryland Dept. of Natural Resources	Garrett
Bell Grove Wildlife Management Area	Maryland Dept. of Natural Resources	Allegany
Billmeyer Wildlife Management Area	Maryland Dept. of Natural Resources	Allegany
Dan's Mountain Wildlife Management Area	Maryland Dept. of Natural Resources	Allegany
Sideling Hill Wildlife Management Area	Maryland Dept. of Natural Resources	Allegany
Warrior Mountain Wildlife Management Area	Maryland Dept. of Natural Resources	Allegany
Mt. Nebo Wildlife Management Area	Maryland Dept. of Natural Resources	Garrett
Deep Run Wildland	Maryland Dept. of Natural Resources	Allegany
Maple Run Wildland	Maryland Dept. of Natural Resources	Allegany
Potomac Bends Wildland	Maryland Dept. of Natural Resources	Allegany
Rocky Gap Wildland	Maryland Dept. of Natural Resources	Allegany
Bear Pen Wildland	Maryland Dept. of Natural Resources	Garrett
High Rock Wildland	Maryland Dept. of Natural Resources	Garrett
Middle Fork Wildland	Maryland Dept. of Natural Resources	Garrett
Savage Mountain Wildland	Maryland Dept. of Natural Resources	Garrett
Savage Ravines Wildland	Maryland Dept. of Natural Resources	Garrett
South Savage Wildland	Maryland Dept. of Natural Resources	Garrett
Youghiogheny State Wild River	Maryland Dept. of Natural Resources	Garrett
Mountain Maryland Scenic Byway	State Highway Administration	Garrett
Chesapeake and Ohio Canal Scenic Byway	State Highway Administration	Allegany

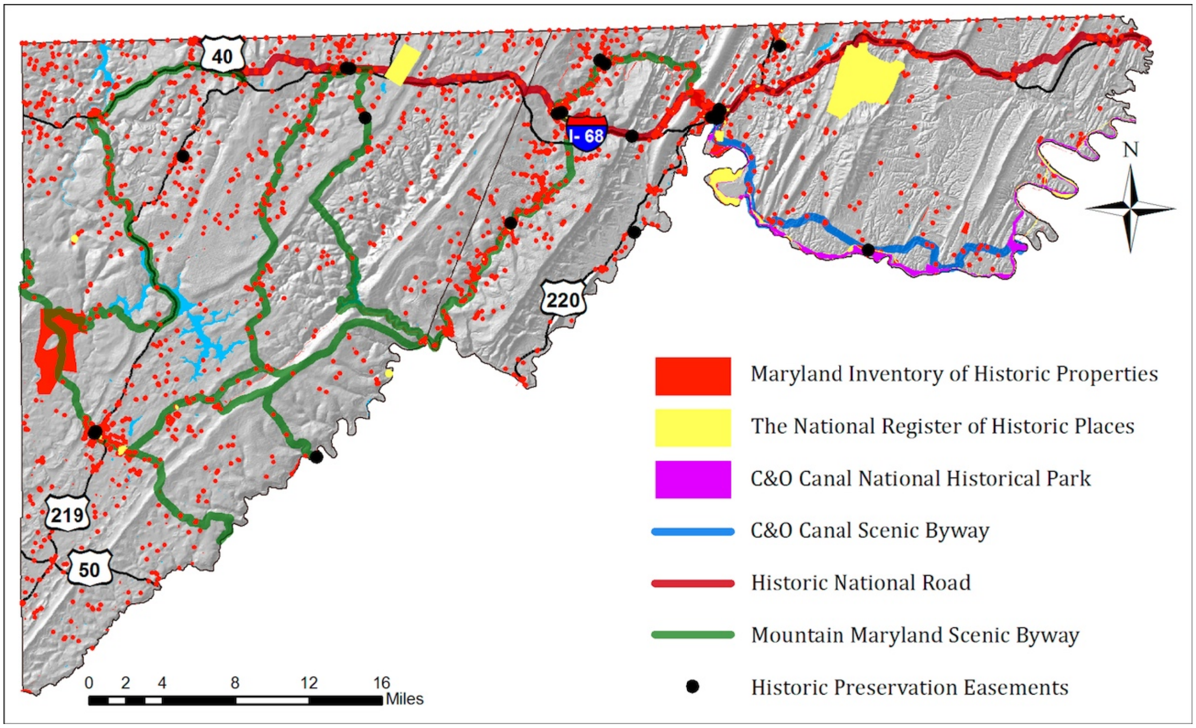

Figure 8-1. Cultural and historical resources in Garrett and Allegany Counties consist primarily of historical districts and registered historic buildings. Scenic byways, Historic National Road, C&O Canal National Historical Park, and major transportation routes are also shown. In the case of the Maryland Inventory of Historic Properties, polygons representing properties smaller than 1 acre have been replaced with a point symbol so that they are visible at this scale. Data provided by the Maryland Historical Trust.

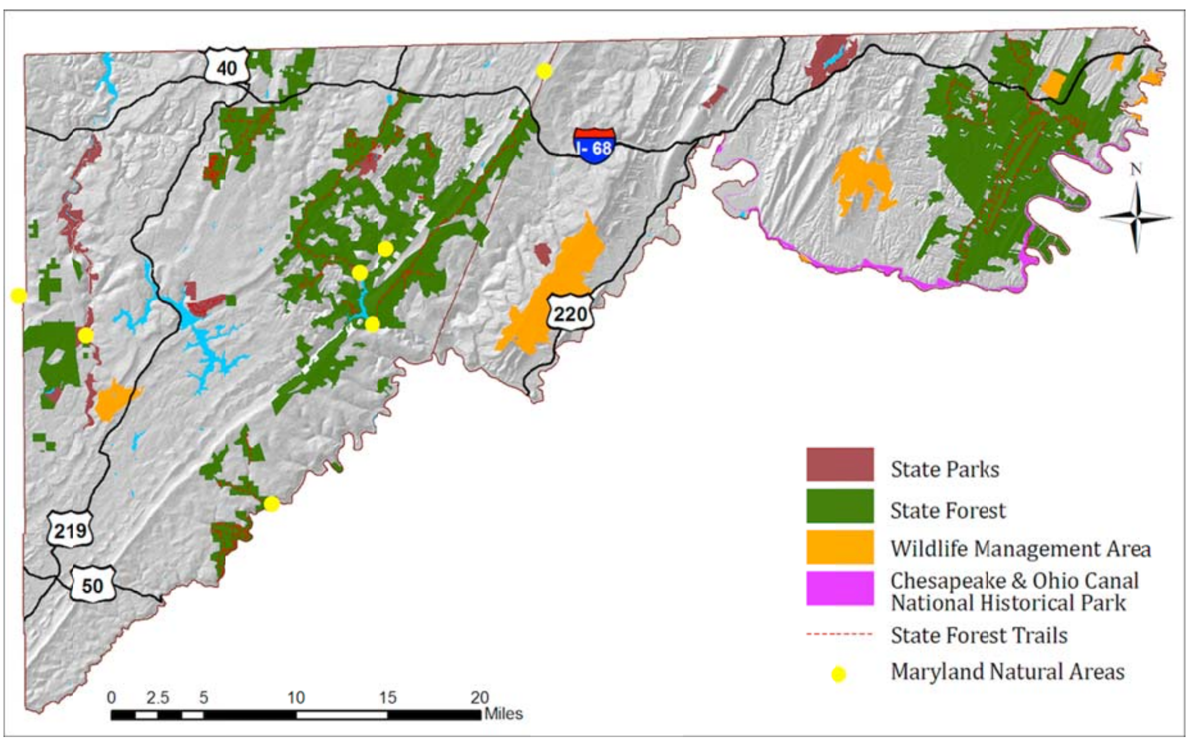

Figure 8-2. Public recreational resources in Garrett and Allegany County are plentiful and contribute to the economic and cultural vitality of the region. With the exception of the Potomac Heritage National Scenic Trail, Mountain Maryland Gateway to the West Heritage Area, and Wildlands (no data available), all resources listed in Table 8.1 are shown here (or in Figure 8-1).

With respect to state forest recreational areas, Pennsylvania DCNR Bureau of Forestry requires a 300 ft setback from any state forest picnic area, trail, road of historic value, tree plantation, overlook, vista, fire tower site, or existing right of way; this setback also affords additional protection of public safety through conflict avoidance. The Bureau of Forestry also relies on local knowledge of cultural sites, recreational trails, trailheads, high use areas, viewsheds, vistas, and high aesthetic areas during the permitting process with a goal of avoiding areas of (or providing increased setbacks from) concentrated recreational activity and developed recreational sites when permitting gas related infrastructure (PADCNR 2011). In the Pennsylvania state forests, an important criterion in site selection for drilling pads is the degree to which locations can provide natural vegetative or topographic screening (PADCNR 2011). Additionally, API recommends that setbacks be increased to take into account prevailing winds and topography; in New York, sites are assessed for their archeological importance (NYSDEC 2011).

Figure 8-3. Many western Maryland recreational sites, such as this section of the C&O canal southeast of Cumberland, draw tourism from eastern portions of the state as well as throughout the Midwest.

Knowledge of potential conflicts with cultural, historical and recreational resources is presumably afforded through good communication between MSGD operators, local governments, and state regulatory and management agencies. Certainly a first step is the identification of the location of cultural and recreational resources potentially impacted by MSGD. However, this should be followed up with an in-depth analysis of the ways in which the local and visiting population uses these resources. API recommends that operators communicate with land owners and/or surface users concerning activities planned for a particular site and provide information on the measures to be taken for safety, protection of the environment, and minimization of impacts to surface uses. The goals of any interactions should be for transparency and increasing the flow of timely and relevant information to surface owners, users, and other stakeholders. As recommended in Pennsylvania (Ubinger et al. 2010), Maryland might consider developing a standardized stakeholder process that could be implemented as part of comprehensive planning strategy; the goal of such a process would be to engage stakeholders and the community in the most effective ways possible, while allowing the permit review process to be expedited.

C. Key recommendations

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).

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.

8-C Applicants should be required to submit a visual resource mitigation plan as part of the permit application process based on site-specific assessment (i.e., viewshed analysis).

8-D Site selection for drilling pads in Maryland should be locations that can provide natural vegetative or topographic screening.

8-E Siting of well pads, or the routing of MSGD-related truck traffic, near high use recreation areas should be avoided if possible.

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.

8-G The calculation of setback distances should consider prevailing winds, topography, and viewsheds, and repeatable formulas for calculating setbacks should be established.

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.

8-I Any permitted shale gas development activities in the vicinity of public recreational 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.

D. Literature cited

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9. Protecting quality of life and aesthetic values[1]

The overall quality of life and aesthetic values in the two western Maryland counties derives in large measure from the mostly undeveloped rural mountainous landscape dominated by forests interspersed with agricultural lands and relatively small towns. The few cities in western Maryland have changed relatively little over recent decades despite explosive population and exurban growth to other parts of the state. The relatively slow-paced way of life, minimal automobile traffic, and associated amenities are attractive features of the area for residents and visitors alike (Wainger and Price 2004, Chancellor et al. 2011). As discussed in Chapter 8, the quality of life is also significantly enhanced by the recreational opportunities afforded by the extensive state and federal public lands that exist in both Allegany and Garrett County. Hiking, biking, hunting, fishing, swimming, and boating are just some of the recreational activities that are afforded through access to the state parks, forests, wildlife management areas, and wildlands in the region (Boller et al. 2010). While providing economic benefits to the region, shale gas development in western Maryland clearly has the potential to negatively impact the area's quality of life and aesthetic character through altered land use, increased traffic (particularly heavy truck traffic), noise pollution, visual and light pollution, and by creating conflicts with ordinary community activities that would not exist in its absence. The purpose of this chapter is to provide recommendations of best practices that could significantly mitigate for these negative impacts. Note that many other practices that address quality of life and aesthetic issues (e.g., constraints mapping for well siting; setback requirements for protecting cultural, historical, and recreational resources, and public safety) were previously addressed in Chapters 1, 8, and 7, respectively.

A. Hours of operation

New York State has proposed that shale gas development activities be conducted in a way that avoids peak traffic hours, school bus hours, museum hours, community events, tourist periods, and overnight quiet periods (NYSDEC 2011). Similarly, as discussed in Chapter 8, Pennsylvania DCNR Bureau of Forestry (PA DCNR 2011) mandates that any permitted shale gas development activities in Pennsylvania state forests be timed to avoid periods of peak recreational activity (e.g., holiday weekends, first day of trout season, whitewater release dates, spring and fall hunting seasons, etc.). Considering the potential intensity of truck transport during the drilling and completion process, a comprehensive plan to protect the quality of life and aesthetic values in western Maryland should include multiple synergistic strategies to limit gas-development related disturbance. Similar to best practices proposed by New York State and employed by Pennsylvania state forests, Maryland could restrict hours and times of operation to avoid or minimize the greatest conflicts, but this practice *by itself* is unlikely to be sufficient. Best management would employ thoughtful siting and visual screens, and rely on restrictions on hours of operation to mediate the most disruptive activities (e.g., during well completion). As discussed in Chapter 1, practices that would be generally effective at reducing conflicts would be: (1) siting well pads away from populated areas (especially those with schools and other regularly-visited

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public buildings); (2) siting well pads and associated facilities in industrial parks designed and zoned for this type of industrial activity; (3) siting well pads in close proximity to major interstate highways and exit ramps designed to efficiently handle round-the-clock transportation; and (4) reducing truck traffic associated with water, chemical, and wastewater hauling (e.g., through use of temporary pipelines). Used in combination with such siting criteria, restrictions on hours and times of operation (based on input from the public) would likely provide significant additional mitigation of the most problematic conflicts.

B. Noise control

Many studies illustrate a link between exposure to noise and negative effects on public health. Noise may severely impair quality of life (disrupt sleep, interfere with speech intelligibility), or possibly give rise to both social and psychological problems (Bodin et al. 2008). Excessive noise also has a broader environmental impact, for instance it can reduce optimal habitat area for critical species or alter their behavior (Yong 2008) (also discussed in Chapter 5). Several states and API provide specific best management practices to deal with issues of noise control. Colorado has established maximum permissible noise levels for oil and gas operations at well sites and gas production facilities. In Colorado, operations involving a pipeline or gas facility installation or maintenance, the use of a drilling rig, completion rig, workover rig, or well stimulation are all subject to the maximum permissible noise levels for industrial zones. In the hours between 7:00 a.m. and the 7:00 p.m., the noise levels of different land uses surrounding an industrial zone may be increased 10 db(A) for a period not to exceed 15 minutes in any one-hour period.[2] New York also has established techniques for assessing, mitigating, and evaluating noise impacts and specific sound levels and characteristics of proposed or existing facilities (NYSDEC 2011). API (API 2011) and these two states have also identified specific BMPs that can be employed for mitigating noise impacts through: (1) careful siting of facilities—distance, direction, timing, and topography are the primary considerations in mitigating noise impacts from hydraulic fracturing and trucking operations (API 2011); (2) requirement for ambient noise level determination prior to operations; (3) placement of walls, artificial sound barriers, or evergreen buffers between sources and receptors (i.e., especially around well pads and compressor stations) (API 2011); (4) use of noise reducing equipment (e.g., mufflers) on flares, drill rig engines, compressor motors, and other equipment (API 2011); and (5) use of electric motors in place of diesel-powered equipment if feasible. We recommend that Maryland require as part of the permitting process: (1) the enforcement of minimum distances between well pads and surrounding homes, businesses, and heavily-used recreational facilities to reduce noise as much as possible; (2) require ambient noise level determination prior to operations; (3) construction of artificial sound barriers where natural noise attenuation would be inadequate; (4) equipping all motors and engines with appropriate mufflers; and (5) requiring electric motors in place of diesel-powered equipment for any operations within 3,000 ft of any occupied building. No drilling or compressor stations should be permitted within 1,000 ft of a residence.

C. Road impacts and transportation planning

Assessing the environmental impact of gas development activities should include an assessment of the impact of vehicle traffic moving into, through, and out of sensitive areas via the existing road network. Such an analysis must determine: (1) which segments of the network are

[2] COGCC Rule 802 Noise Abatement

accessible to vehicular traffic; (2) when they are accessible; and (3) to what classes of vehicles they are accessible. The road network in Garrett and Allegany County consists of several primary roads supported by a dense network of secondary roads (Figure 9-1). However, limitations and barriers to vehicle traffic are many, including one-way streets, scenic byways, one-lane and restricted weight bridges, gates, speed bumps, low-pass bridges, railroad crossings, etc. In a formal traffic network analysis, these features are used to constrain the flow of traffic resulting in the determination of a least-cost path between any two locations. The advantages of such an approach are that it can incorporate multiple types of information, gathered from state, county, and local sources, and it synthesizes the many constraints that should be considered in attempts to reduce the severity and number of conflicts between gas-development related traffic and existing uses of roads. Consistent with practices recommended by API and the states of Colorado and New York, 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 workover, or well completion activities; the approval process should also allow for adequate comment by the public, state transportation agencies, and county roads departments to specifically identify potential road use conflicts or issues unbeknownst to the applicant or the primary state regulatory agency (since all road issues are really local issues).

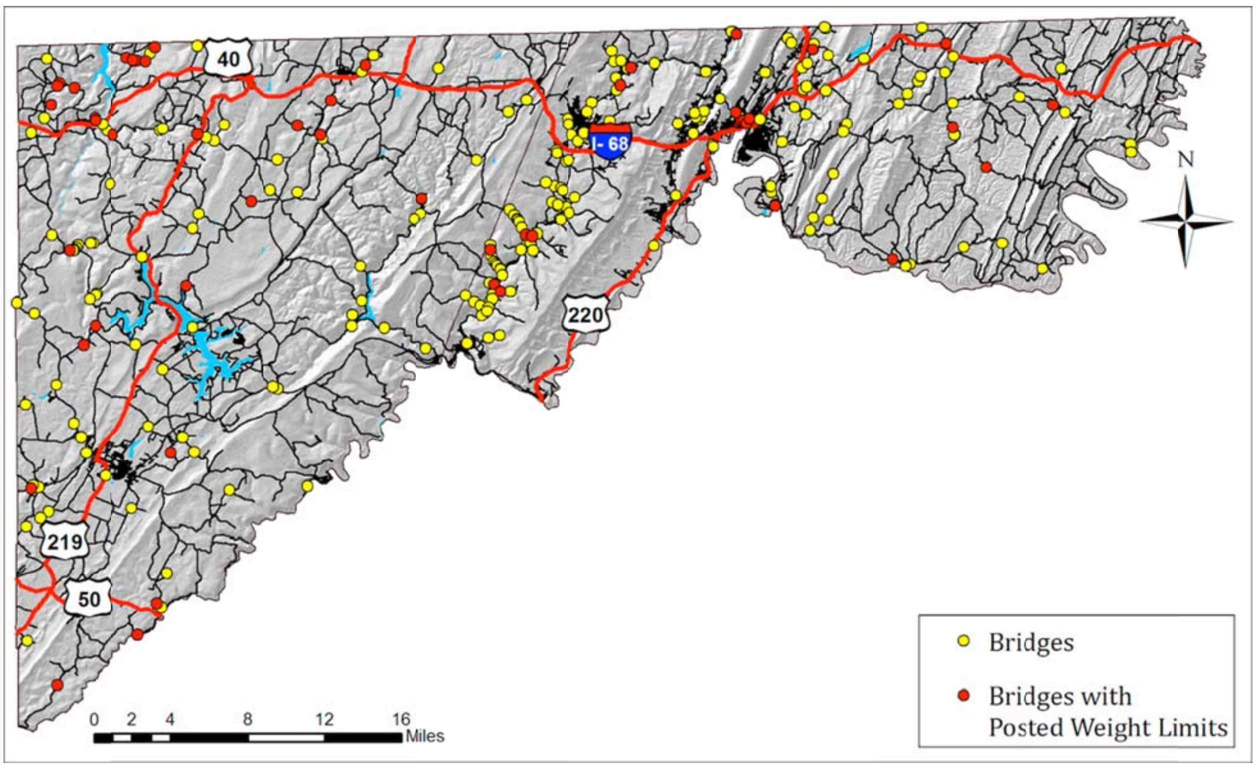

Figure 9-1. The road network of Allegany and Garrett County is relatively sparse. Because roads are often confined to areas with reduced topographic slope, many stream valleys contain roads. This, combined with other restrictions mentioned in the text, suggest that increased truck traffic on this road network will have multiple impacts on the quality of life and aesthetic values in the region. Road data were acquired from the Maryland State Highway Administration (SHA).

The required transportation plan would be a detailed, comprehensive document including network analysis and plans for other transportation-related activities. Such a plan would be designed to achieve the following: (1) maximize efficient driving; (2) route vehicles onto roads and across bridges specifically designed to carry heavy truck loads on a repetitive basis; (3) ensure public safety; (4) avoid peak and sensitive traffic hours; (5) ensure that all trucks are DOT compliant; (6) coordinate with highway departments and emergency responders; (7) upgrade/improve roads as needed; (8) inform the public of any necessary detours; (9) utilize flowlines to reduce truck traffic (if feasible and cost effective); and (10) assure adequate off-road parking at well site and delivery areas (API 2011). Further, as proposed in New York, any deviation from the plan, detours or closures, must be done with advanced public notice. Road-use agreements should also be established between operators and municipalities to ensure public safety and provide a mechanism for addressing road damages attributable to shale gas development in a timely way.

Existing roads should be utilized wherever feasible; if new roads are needed, however, potential impacts should be considered along with landowner recommendations, consideration for historical and cultural resources, and a mitigation strategy to prevent erosion and protect environmentally-sensitive areas. Both API (API 2009) and Pennsylvania DCNR (PADCNR 2011) provide specific recommendations for the design and construction of new roads in rural landscapes. While roads should be designed and constructed in ways appropriate for their intended use, it is recommended that construction crews consider using the PA DNCR for construction of permanent non-paved roads to address potential environmental impacts, control erosion, and avoid damage to environmentally sensitive areas (PADCNR 2011).

D. Visual pollution/viewsheds

As discussed in Chapter 8 in the context of protecting cultural, historical and recreational resources, there are two types of mitigative techniques that are appropriate for addressing visual pollution and minimizing degradation of visually sensitive resources in general. The first type of technique involves the use of viewshed analysis to help carefully site well pads and associated infrastructure at locations that are least visible from heavily used roads, overlooks, or public recreational facilities. The second type of mitigation involves the use of visual screens, camouflages, paint schemes, evergreen buffers, and landscaping techniques to obscure drilling equipment and shale gas development activities from view as much as possible. We recommend use of both types of mitigative techniques to minimize degradation of western Maryland viewsheds by shale gas development activities as much as possible. It should be emphasized that because well drilling and completion operations that employ large amounts of heavy (and, in some cases, three stories tall) equipment on-site are

Figure 9-2: Drill rigs must be lit at night to facilitate 24-hr operations, however, during the production phase artificial lighting might be eliminated.

temporary in nature, the most severe degradation of visually-sensitive resources occurs during periods of maximum development activity. We believe that removal of major equipment alone would in some cases contribute significantly to restoring these natural viewsheds. In other cases, careful land reclamation practices (e.g., revegetation of well pads, planting of evergreen screens around permanent gas infrastructure, etc.) would provide additional benefits (see Chapter 4).

Light pollution has the added potential (above and beyond general impacts to viewsheds) to pose significant direct and indirect effects on the quality of life and aesthetic values in western Maryland (Figure 9-2). Indirect effects of light pollution were covered in Chapter 5, and take the form of the different ways in which artificial lighting can influence wildlife and biological diversity more generally. Artificial lighting causes direct effects on the quality of life and aesthetic values by being a distraction while driving on primary and secondary roads, obscuring dark night skies, and reducing the rural aesthetic qualities of the region. Many visitors to western Maryland frequent campgrounds and other state facilities, and expect dark night skies as part of their experience. Maryland could put an emphasis on preserving these conditions. Similar to what was discussed in Chapter 5, the primary BMPs for reducing the impact of artificial light aim to reduce the amount of lighting used, keep lights low and directed down on the work site as much as possible, and increase the use of low-pressure sodium lights relative to other types of lighting. Most polluting are lamps with a strong blue emission, like metal halide and white light-emitting diodes (LEDs) (Falchi et al. 2011). Following these guidelines, Maryland could take steps to reduce the amount and nature (color) of artificial lighting used during MSGD. It should also be noted that the light required at different stages of MSGD can vary substantially; while high light levels might be required during drilling and well completion, during production artificial lighting could be reduced or eliminated altogether (after addressing security concerns.)

E. Key recommendations

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.)

- 9-A.1 Site well pads away from occupied buildings (e.g., dwellings, churches, businesses, schools, hospitals, and recreational facilities)
- 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
- 9-A.3 Site well pads in close proximity to major interstate highways and exit ramps designed to efficiently handle round-the-clock transportation
- 9-A.4 Reduce truck traffic associated with water hauling through use of temporary pipelines where possible.

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.

9-C No drilling or compressor stations should be permitted within 1,000 ft of an occupied building.

9-D Require electric motors (in place of diesel-powered equipment) for any operations within 3,000 ft. of any occupied building

9-D.1 Encourage electric motors in place of diesel-powered equipment wherever possible.

9-D.2 Restrict hours and times of operation to avoid or minimize the greatest conflicts between the public and MSGD.

9-D.3 Require ambient noise level determination prior to operations.

9-D.4 Require construction of artificial sound barriers where natural noise attenuation would be inadequate.

9-D.5 Equip all motors and engines with appropriate mufflers.

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

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.

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.

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.

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 Maryland viewsheds by MSGD.

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10. Protecting agriculture and grazing[1]

After forested land, agricultural land is the second largest contributing land cover in Allegany and Garrett Counties on an areal basis, covering 15.6% (108,420 acres) of these two counties. In 2007, the most recent year for which data are published, it is estimated that Allegany County had 302 farms covering a land area of 36,343 acres[2], while Garrett County had 677 farms covering 95,514 acres.[3] The value of all agricultural product sales in the two counties was estimated as $3.16M and $27.73M, respectively. Farms in these two counties are typically small family operations, with the average farm covering 121 acres in Allegany and 141 acres in Garrett County[4]. While many types of county-level data from the National Agricultural Statistics Service are not published to protect economically sensitive information, major crops produced in these two counties include corn for grain, corn for silage, soybeans, winter wheat, other hay, barley, and vegetables, in addition to milk, cattle and calves, sheep, hogs, and poultry. In addition to the economic value of crops and other agricultural production, agriculture also contributes aesthetically to the quality of life and cultural fabric of rural western Maryland as discussed in Chapter 9. While important in this regard, it must be noted that agricultural production in both western Maryland counties is dwarfed by production in many other counties in the state. For example, Carroll County which has about 142,000 acres in farmland as of 2007 (roughly the same acreage as Allegany and Garrett Counties combined) had agricultural product sales that were about a factor of three greater ($87.4M).[5] This difference is consistent with the generally low fertility soils and cool climate of western Maryland. Nonetheless, as an important economic activity in the region and as a component of Maryland's general effort to maintain farming activities throughout the state, contributing to overall quality of life, we believe that there are some best practices that can protect both cropland and grazing land from negative impacts of shale gas development.

One recent study of farm animals in six states (Pennsylvania, New York, Ohio, Colorado, Texas, Louisiana) suggested increased mortality rates in livestock and companion animals (i.e., dogs and cats) living close to active gas-drilling operations (Oswald and Bamberger 2012), with several caveats associated with the lack of controls due to the case study aspect of the survey (Thompson 2012). Although chemicals can be volatized (e.g., by impoundment aerators) and misted into the air creating an inhalation exposure pathway, the most common source of toxicity exposure was likely via contaminated water. Pathways of exposure included, for example, spills of hydraulic fracturing fluids, tears in the liners of wastewater impoundments (which we do not recommend but have been used in PA), and spreading of wastewater on roads to reduced dust and ice followed by animals licking their paws after crossing the roads (again, the spreading of wastewater on roads is not recommended for Maryland). Health impacts ranged from neurological to sudden death with the most common effects being reproductive. Animals affected include cows, horses, goats,

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[2] Allegany County 2010 Agricultural Profile, Maryland Department of Agriculture. http://www.mda.state.md.us/on_web/ag_links/countyag.php#allegany.

[3] Garrett County 2010 Agricultural Profile, Maryland Department of Agriculture. http://www.mda.state.md.us/on_web/ag_links/countyag.php#garrett.

[4] The difference between agricultural land area and farm area in these counties is likely due to the presence of woodlots on many of these farms. In other words, some of the farm area is actually mapped as forest cover.

[5] Carroll County 2010 Agricultural Profile, Maryland Department of Agriculture. http://www.mda.state.md.us/on_web/ag_links/countyag.php#garrett.

llamas, chickens, dogs, cats, and koi. Because the movement of farm animals is confined they may experience higher cumulative exposure than wildlife with less restricted mobility. However, photographic evidence has been reported of dead and dying songbirds, deer, frogs, and salamanders (Oswald and Bamberger 2012).

A. Protection of prime farmland

Prime farmland is an official designation used by U.S. Department of Agriculture to define land that has the best combination of physical and chemical characteristics for producing important agricultural crops. Prime soils have the following inherent characteristics: a minimum amount of surface rocks, low susceptibility to erosion and have not had been excessively eroded in the past, a favorable pH, an acceptable level of content of salt and sodium, water and air permeability, and are not subject to prolonged saturation. They also have the following related qualities: have nearly level to gently sloping topography, and rarely or never flood during the growing season.[6] Fewer than 2% of western Maryland soils are considered prime soils[7], and 71% are considered class VI or VII, designating them as suitable for planting of permanent pasture, trees, or reserved for wildlife management and recreation[8]. As recommended by Lien and Manner (2010), we agree that soil conditions at sites being considered for shale gas development be evaluated as part of the planning process; prime agricultural soils and prime farmland should generally not be disturbed for well pad siting, road construction, or any ancillary gas development activities. Further, highly erodible soils should also be identified as part of the planning process and appropriate best practices should be employed to prevent erosion and sedimentation problems in developing these areas (see Chapter 4).

Some agricultural lands in western Maryland are already protected to some extent by the Maryland Agricultural Land Preservation Foundation (MALPF). MALPF—which protects agricultural land in Maryland through the use of perpetual easements—was created by the Maryland General Assembly in 1977 and is housed within the Maryland Department of Agriculture (MDA). Prior to 2007, applications for easements were only accepted from landowners in designated Agricultural Preservation Districts. Easements may be donated or purchased with a goal of providing for the perpetual production of local food and fiber. Agricultural land easements in western Maryland are displayed in Figure 10-1 and comprise about 4.3% of the agricultural land in the two counties. The text in the current standard deed of easement found at the MALPF website reads as follows: “No rights-of-way, easements, oil, gas or mineral leases, or other similar servitude may be conveyed, or permitted to be established on the land for any commercial, industrial or residential use, without the Grantee's express written permission.”[9] Thus, any surface uses of the land for shale gas development without the Grantee’s (i.e., state of Maryland’s) written permission would appear to expressly violate the protective status granted under MALPF.

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[6] http://www.md.nrcs.usda.gov/technical/nritext.html.
[7] Ibid.
[8] Land Capability Classification. Agriculture Handbook No. 210. Soil Conservation Service. U.S. Department of Agriculture. Issued September 1961. Reprinted January, 1973
[9] Current Standard Deed of Easement, para. II.A.2, pp. 3-4, Maryland Agricultural Land Preservation Foundation; http://www.malpf.info/laws.html

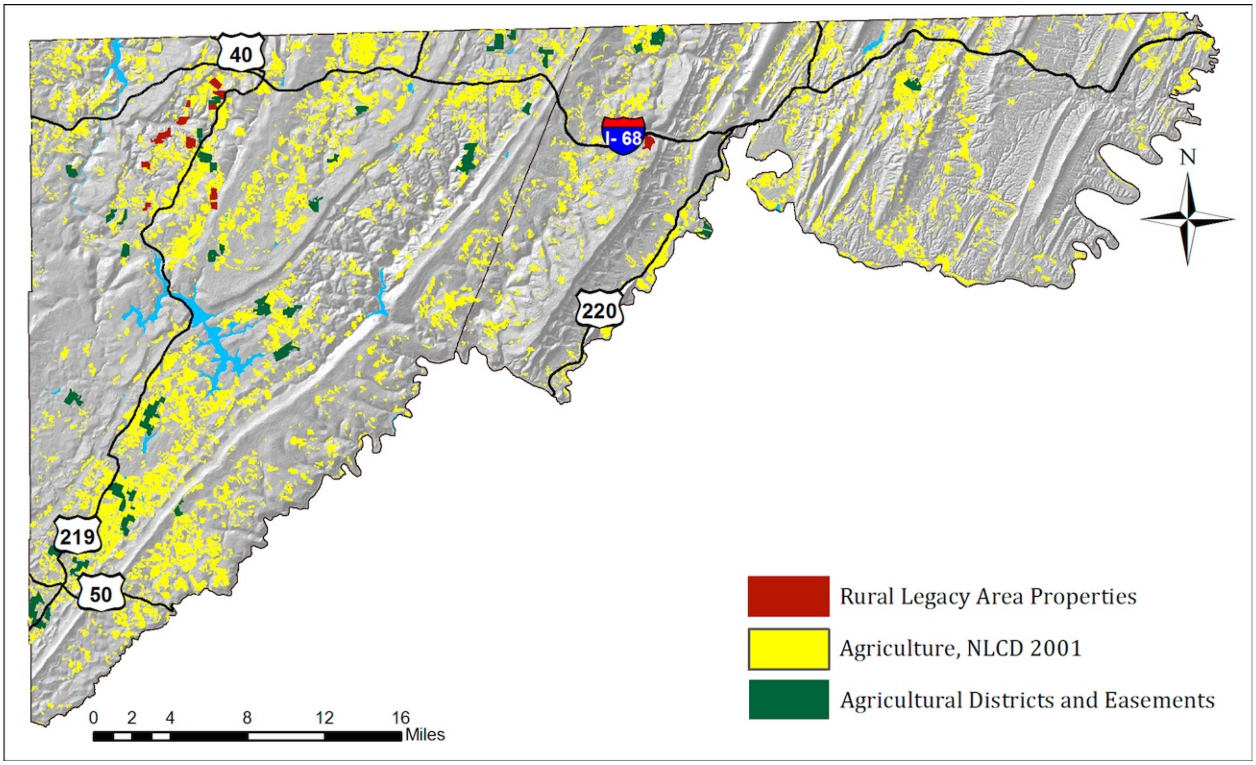

Figure 10-1. Agricultural land is generally confined to floodplains (Allegany County) and the Appalachian Plateau (Garrett County). Maryland Agricultural Land Preservation Foundation (MALPF) agricultural easements (sometimes located within agricultural districts) protect land from non-agricultural uses and are administered by Maryland Department of Agriculture. Rural Legacy Area Properties have multiple goals, including to protect economies based on farming and forestry, and are administered by the Department of Natural Resources.

A second mechanism through which agricultural land has been protected is Maryland's Rural Legacy Program, which was enacted by the General Assembly in 1997, and has dedicated over $210 million to preserve 68,675 acres of valuable farmland, forests, and natural areas throughout the state[10]. In western Maryland, 62,747 acres have been identified as Rural Legacy Areas, a subset of this area has been protected through conservation easements (Figure 10-1). The Rural Legacy Program's goals are to establish greenbelts of forests and farms around rural communities to preserve their cultural heritage and sense of place, and critical habitat for native plant and wildlife species. Relevant to prime farmland, the Rural Legacy Program also aims to support natural resource economies such as farming, forestry, tourism and outdoor recreation. Similar to MALPF conservation easements, subsurface activities on Rural Legacy properties are prohibited without the Grantees' approval and require the Grantee to consider whether the impact would be destructive of the conservation attributes the easements were designed to protect. In Garret County, the Bear Creek Rural Legacy Area overlays the Accident gas storage dome, and was established by the Maryland Department of Natural Resources in collaboration with Garrett County to protect farms with severed or leased mineral rights with the understanding that gas storage activities would continue to take place on lands encumbered with Rural Legacy easements, provided that such storage activities do not unduly compromise the natural and working resources the Area were established to protect. In Allegany County, the Mountain Ridge Rural Legacy Area is delineated around 10,163 acres of existing protected lands that may be further connected and

[10] http://www.dnr.state.md.us/land/rurallegacy/12thAnniversary.asp

consolidated, forming a greenway potentially linking ridgetops in West Virginia with Pennsylvania, as well as westward into the Allegheny Plateau.

Protected lands throughout western Maryland have clearly been established with consideration of agriculture and prime soils as an objective. Therefore, restricting MSGD so as to preserve prime soils and agricultural lands could be achieved by enforcing MALPF and Rural Legacy Area easements throughout western Maryland. From our reading of the MALPF and Rural Legacy Program websites, it appears this would just require that Maryland not approve any MSGD in these areas. With respect to other non-protected agricultural lands where shale gas development might be permitted, some of the best practices proposed by New York State would provide an appropriate level of protection, of agriculture and grazing, namely (NYSDEC 2011):

- Well pads, infrastructure, roads, and utility corridors should generally be sited along field edges, thus avoiding bisection of fields.
- Topsoil should be stockpiled during site development activities, covered during storage, and redistributed back onto agricultural land as part of the land reclamation process.
- In active agricultural areas, operators must: (1) keep drill cuttings and topsoil separate; (2) remove any drilling muds from fields; (3) avoid soil compaction; and (4) fence in active pasture areas (alternately fence livestock out of gas development areas).

B. Key recommendations

10-A Soil conditions at sites being considered for shale gas development should be evaluated as part of the planning process.

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.

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).

10-D Well pads, infrastructure, roads, and utility corridors should generally be sited along field edges, thus avoiding bisection of fields.

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.

10-F Operators must fence livestock out of gas development areas.

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