The Potential Environmental Impact from Fracking in the Delaware River Basin

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Cleared for Public Release

ANALYSIS & SOLUTIONS

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Abstract

This study aims to model the landscape of the Marcellus Shale region to predict how it may change in the future in response to the expansion of natural gas extraction, and, in particular, what impact this may have on the Delaware River Basin (DRB). Our approach combined geospatial analysis and statistical modeling to create a probability surface that predicts the most favorable locations for the placement of future wells based on the location of existing wells. Using the probability surface and an estimate of the number of wells that would be needed to fully exploit the shale resource, we estimated the future landscape of development in the Interior Marcellus Shale and DRB. Using affected subwatersheds and counties as study areas, we then investigated potential impacts associated with land cover, water and wastewater management, water quality due to changes in land cover, air emissions, and health risk factors. The results are intended to help decision-makers and the public understand the scale of the potential impacts.

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Executive Summary

Hydraulic fracturing, or "fracking," combined with horizontal drilling, has opened up natural gas fields that were previously thought to be inaccessible; however, this activity has the potential to impact the regional environment. To date, there has been no systematic analysis to evaluate multiple impacts of fracking in an integrated way. Published research has predominantly looked at individual environmental impacts associated with fracking in a subset of wells. Few studies have considered multiple impacts, and no study has provided a reasonably complete, integrated regional environmental assessment of fracking. We aim to help fill this knowledge gap and inform the public debate concerning fracking by providing comprehensive, long-term estimates of a set of environmental impacts of natural gas fracking in the Interior Marcellus Shale. This play, which covers parts of Pennsylvania, New York, West Virginia, Maryland, and Ohio, is now considered to be the second-largest gas field in the world.

This research project models the potential natural gas development of the Marcellus Shale to predict what environmental impacts this expansion may have on the Delaware River Basin (DRB). The DRB—which spans Pennsylvania, Delaware, New Jersey, and New York—contains one part of the Interior Marcellus Shale play where fracking has been under a moratorium, by the Delaware River Basin Commission. (The State of New York has separately banned hydraulic fracturing after implementing a five-year moratorium). For this reason, the DRB is a good candidate for a prospective analysis of potential impacts.

Our approach combines geospatial analysis and statistical modeling to create a probability surface that predicts the most favorable locations for the placement of future wells based on the locations of existing wells. Using the probability surface and an estimate of the number of wells that would be needed to fully develop the shale resource, we estimated the future landscape of development across the Interior Marcellus Shale.

We then investigated the potential impacts of this development on land cover, water and wastewater management, water quality, air emissions, and health risk factors in three DRB sub-watersheds. Our calculations were designed to give reasonable upper bounds on each of these potential impacts. Based on our analysis, we offer the following key points to help stakeholders and decision-makers evaluate the potential impacts of natural gas development:

- If the moratoriums on fracking were lifted, there could be as many as 4,000 **wells** fracked in the Interior Marcellus within the DRB in future years, requiring between 500 – 1,000 **well pads**.
- Development of natural gas infrastructure including well pads, and rights-of-way for access roads and natural gas gathering lines, results in 17-23 acres of **land cover disturbance** per well pad. In watersheds we studied, this land cover disturbance could reduce forest cover directly by 1-2 percent, and result in a 5-10 percent reduction in **core forest area**.
- **Water withdrawals** during periods of maximum well development could remove up to 70 percent of water if taken from small streams during low-flow conditions, and less than 3 percent during normal flow conditions.
- Discharge of **wastewater effluent** from fracking could raise in-stream concentrations of some key contaminants (notably barium and strontium) up to 500 percent above reference values during maximum development periods at low-flow conditions, if all wastewater were treated to Pennsylvania effluent standards.
- Land cover conversions could increase **erosion rates** up to 150 percent during the initial development phase and up to 15 percent in a post-development state, despite affecting less than 3 percent of land cover in affected watersheds we studied.
- The installation of multiple **compressor stations** (needed to transport gas away from wells through pipelines) in the DRB could as much as double nitrogen oxide emissions in the impacted counties (compared to present-day, county-wide emissions).
- In the DRB, roughly 45,000 people would live within one mile of the projected well pad locations, a distance that has been related to **health risk factors** in scientific literature. This population would predominantly reside in Wayne County, PA, where nearly 60 percent of the county's population (over 30,000 people) may be affected.

Of these risks, changes to land cover and associated impacts to area forests, hydrology, and water quality appear the most likely to occur and most difficult to mitigate completely. The water and wastewater and air quality risks pose some significant management challenges, but the actual level of impact is uncertain and highly influenced by potential regulation and policy. The health risks require more study because a significant number of people in the Upper Delaware River Basin live in areas that are close to potential well locations.

This report presents an estimate of full natural gas development based on technically recoverable resources in the Interior Marcellus Shale play, and focuses on some of the locations where concentrated development can reasonably be expected in the DRB portion of the play (if development were allowed). As such, the well development projections and associated impact calculations likely would be a conservative (high-end) estimate of potential development or impacts. Actual development will ultimately depend on laws and regulations, ability to sign leases, ability to recover gas, and economics (price of gas, cost of production, well productivity, etc.). While regulatory, economic, and other factors may limit the actual level of development, policymakers should be prepared to handle the impacts from a scenario in which the shale resources could be fully developed.

This study only investigates the Interior Marcellus shale play, and does not consider other shale plays underlying the DRB such as the Utica Shale. This study does not examine the full range of potential impact categories that the region may experience, does not consider all potential impact pathways (e.g. accidental wastewater discharges), and it does not project possible environmental and human health outcomes based on the impacts.

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Glossary

Ba	Barium
Bcf	billion cubic feet
BMP	Best Management Practice
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CO_2	carbon dioxide
Cl	Chloride
DRB	Delaware River Basin
DRBC	Delaware River Basin Commission
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESRI	Environmental Systems Research Institute
EUR	Estimated Ultimate Recovery
GIS	geographic information system
GW	groundwater
HUC	hydrologic unit code
JAS	July-August-September
Maxent	maximum entropy (modeling technique)
MGD	million gallons per day
NEI	National Emissions Inventory
NLCD	National Land Cover Dataset
NO_x	nitrogen oxides
PADEP	Pennsylvania Department of Environmental Protection
PAH	polycyclic aromatic hydrocarbon
PM	particulate matter
SO_x	sulfur oxides
SO_4	sulfate
Sr	Strontium
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
TN	Total Nitrogen
TP	Total Phosphorus
UNGD	unconventional natural gas development
USGS	U.S. Geological Survey
VOC	volatile organic compound
WW	wastewater

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Introduction

Hydraulic fracturing, or "fracking," combined with horizontal drilling, has allowed access to natural gas in shale deposits previously thought to be inaccessible. This type of unconventional natural gas development (UNGD) has significant implications for energy supplies and fuel choice in the American economy. For the first time in 30 years, coal's share of power generation dipped below 40 percent in 2012, while gas's share increased. Leading this charge is the Marcellus Shale play, which currently accounts for almost 40 percent of U.S. natural gas production and is projected to increase [1]. This play, which covers parts of Pennsylvania, New York, West Virginia, Maryland, and Ohio, is now considered to be the second-largest gas field in the world.

While these newly accessible resources are transforming the nation's energy economy, the fracking process carries a potential environmental burden in the nature and scale of the extraction activities involved—particularly well development [2-7]. The amount of water required to fracture a well typically varies from one to five million gallons (but can be more depending on well-specific conditions). Much of the water that is tapped to inject into the wells contains a variety of chemicals and additives to aid in fracturing the shale rock. About 80 percent of the injected water is consumed by the process (i.e., remains underground), and the "produced water" that returns to the surface must be handled as required by environmental law. The nature of well pad development has raised concerns over soil erosion, sedimentation/siltation, and eutrophication of nearby streams, as well as ecosystem fragmentation. Local air quality could suffer from increased ozone creation, the release of volatile organic compounds and toxic chemicals, greenhouse gas emissions from fugitive methane releases, and increased airborne particulates from extensive diesel engine use. These are potential environmentally hazardous byproducts of the fracking process itself.

While recent years have seen a significant increase in the peer-reviewed literature on the various impacts of fracking, substantive data gaps remain [8]. To date, there has been no systematic analysis to evaluate the multiple, integrated impacts of fracking. Published research has looked predominantly at individual environmental impacts associated with fracking in a subset of wells. Few studies have considered multiple impacts, and no study has provided a reasonably complete, regionally integrated environmental assessment of fracking, or developed the methodology to do so. Thus, even with more information, regulators are left attempting to extrapolate study results to their region to assess impacts—and at a time of shrinking government budgets and resources.

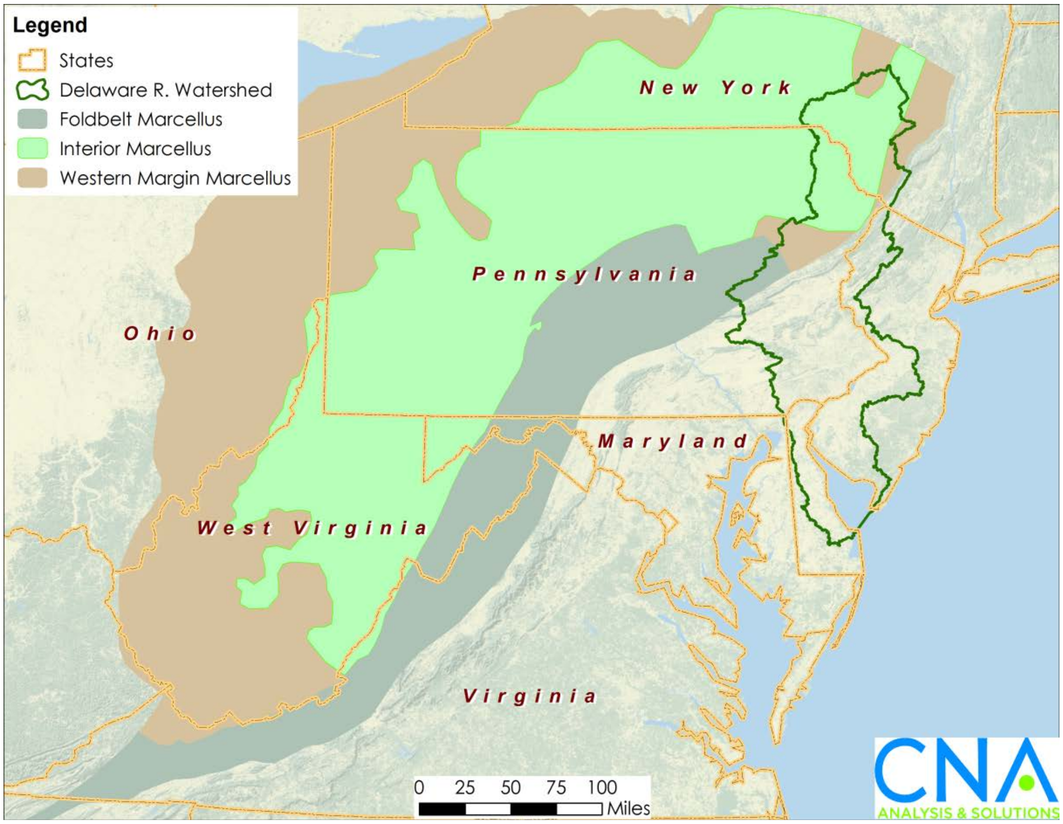
One of the primary barriers to conducting this type of research is the difficulty in predicting where future natural gas wells will be located. For example, in a recent report to Congress, the U.S. Government Accountability Office stated, "The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse effects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many and where shale oil and gas wells may be constructed" [9]. With this report, our objective is to correct this critical deficiency in the research.

The Delaware River Basin (DRB)—which spans Pennsylvania, Delaware, New Jersey, and New York—contains one part of the Marcellus Shale play that has not been developed (see Figure 1 on the following page); therefore, it is a good candidate for a prospective analysis of potential impacts. Due to state and regional regulation, gas development is currently limited in the DRB. The State of New York recently announced a ban on hydraulic fracturing after investigating its impacts during a five-year moratorium on the practice. Similarly, in the Pennsylvania portion of the basin, no hydraulic fracturing has occurred because the Delaware River Basin Commission (DRBC) has had a moratorium in place on the practice for some years. In this analysis, we investigate a hypothetical case where no moratorium prevents development.

Furthermore, this analysis focuses on the Interior Marcellus, which is most suitable for gas development with hydraulic fracturing. The Western Margin Marcellus is generally less than 50 feet thick, and the Foldbelt Marcellus shows the extent of the shale formation, but is generally not thought to be deep enough or thick enough for development.

In this report, we summarize the methodology to identify the probable placement and extent of future wells in the DRB region of the Interior Marcellus Shale through the statistical evaluation of existing well locations in the play. We then demonstrate the utility of the well-development projections to evaluate a variety of potential environmental impacts to some subwatersheds of the DRB. These impacts include land cover disturbance, including forest fragmentation; issues related to water and wastewater management; water quality issues resulting from changes to land cover; air quality issues; and affected population. Each chapter of the report examines one of these impacts in the context of existing basin conditions, as well as relevant activities where appropriate, for framing of results.

Figure 1. The extent of the Marcellus Shale play and the Delaware River Basin. This study focuses on the Interior Marcellus.



Source: U.S. Geological Survey (Marcellus, DRB), U.S. National Park Service (Terrain Basemap)

Understanding this report

This report presents an estimate of full natural gas development (based on technically recoverable resources) in the Marcellus Shale play, and focuses on some of the locations where concentrated development can reasonably be expected in the Delaware River Basin portion of the play. As such, the development projections and associated impact calculations likely would be a conservative (high-end) estimate of potential development or impacts. Actual development will ultimately depend on laws and regulations, ability to sign leases, ability to recover gas, and economics (price of gas, cost of production, well productivity, etc.). Like the projections for well pad development, we calculated potential impacts using several scenarios to give reasonable upper bounds of potential impacts. While regulatory, economic, and other factors may limit the actual level of development, policymakers should be prepared to handle the impacts from a scenario in which the shale resources could be fully developed.

We project locations to calculate impacts, but they should *not* be interpreted as explicit *predictions* of where wells will actually go. Although high-resolution spatial data allows fairly precise well pad siting, this analysis is most useful for identifying which portions of the Marcellus Shale may be most suitable for development (relative to all the others). Actual locations of wells depend on many site-specific factors, not the least of which is a legal lease contract to perform drilling on a property. Furthermore, the projected well pad locations should not be used to estimate impacts at small scales, such as for individual parcels or neighborhoods.

Instead, the level of impacts estimated in this report should be viewed as a first iteration of investigating a range of potential impacts. While the impacts selected cover a broad range of topics, there are other potential impacts that are not covered here (e.g. truck traffic, long-range transmission pipelines, or induced seismicity). The selected impacts in this report are suited to analysis using the well pad projections; are documented in peer-reviewed literature; and are likely to occur, given current trends in the development of the gas sector. We present each potential impact in its own chapter with its own analysis, though all depend on the projections of wells and well pads. Furthermore, this report only examined the potential for development of wells and well pads in the portion of the Marcellus Shale play that underlies the DRB; there are other shale formations (e.g., the Utica Shale and Newark Basin) that lie beneath that DRB that were not considered in our projections.

We selected study areas, scenarios, and analysis methods to investigate the range of outcomes associated with each impact category. Table 1 outlines the assessment unit, development scenarios, and additional analysis scenarios for each section. The assessment unit is the geographic area under consideration. For land- and water-related impacts, we used the drainage areas of defined subwatersheds in the basin with extensive projected gas development. For impacts to air quality and human health, we used counties as study areas.

We generated projections for well development for two well pad–density scenarios: a *concentrated* scenario (eight wells per pad = fewer well pads) and a *dispersed* scenario (four wells per pad = more well pads). The land cover changes, water quality issues from land cover changes, and health risk are all related to the development of well pads (and associated infrastructure). By contrast, the water/wastewater and air quality impacts depend primarily on the number of wells. Since the number of wells is approximately equal for the scenarios, the well pad density is not important when analyzing these impacts and only one scenario was selected. The water and wastewater management chapter used the "concentrated" scenario because slightly more wells were developed in the assessment units being considered than for the "dispersed" scenario.

Furthermore, each chapter's topic required additional analysis dimensions particular to the impact to capture the potential consequences. For example, water/wastewater and air quality results depend on the rate of well development per year, so we investigated scenarios for average yearly development and for maximum development within a year. The water quality impacts associated with land cover disturbance vary over time, such as during initial infrastructure construction or after infrastructure is built and the gas wells are in production. Finally, we investigated the affected population affected at six different distances from the nearest well pad, which academic literature uses in evaluating certain health risk factors as a function of distance from the well pad.

Table 1. Chapter breakdowns of analysis in this report. Land cover and water impacts were considered at the drainage basin level; air and health impacts were considered at the county level.

Report Chapter Topic	Assessment Unit	Development Scenarios	Additional Analysis Dimensions
Land Cover Changes	Drainage basin	Both	• Direct Conversion • Forest Fragmentation
Water and Wastewater Management	Drainage basin	*Concentrated*	• Average Dev. • Maximum-Year Dev. • Wastewater reuse
Water Quality	Drainage basin	Both	• Initial Infrastructure • Post-Development
Air Quality	County	*Dispersed*	• Average Dev. • Maximum-Year Dev.
Health Risks and Affected Population	County	Both	• Six distances from well pad

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Potential Natural Gas Development in the Marcellus Shale

Key Findings

- Based on Energy Information Administration resource estimates for technically recoverable reserves, the Interior Marcellus could see an additional 63,000 wells developed in the future. Our analysis did not include other portions of the Marcellus, or other shale plays in the region.
- Most of the future development in the Interior Marcellus would be expected in Pennsylvania (74 percent), followed by West Virginia (19 percent), New York (4 percent), Ohio (2 percent), and Maryland (1 percent), assuming no moratoriums throughout the Marcellus region.
- Eleven counties in Pennsylvania could each see development of over 2,000 additional new wells, including Wayne County in the DRB.
- Were the moratoriums in the DRB lifted, there could be approximately 4,000 wells at full development of the Interior Marcellus. This number of wells would require 500 – 1,000 well pads depending on the number of wells per well pad.

This chapter presents the current landscape of the Marcellus Shale play in order to predict how the landscape may change in the future in response to the expansion of natural gas extraction. In particular, we focus on the potential development in the Interior Marcellus Shale Assessment Unit (see Figure 1 on page 3), since 95 percent of the shale's reserves are estimated to fall within this boundary [10], and 98 percent of the new wells developed in the region since 2011 have been within this boundary. We then focus our analysis to determine where this development would most likely extend into the Delaware River Basin if the moratoriums on drilling were lifted.

To predict the most likely locations for the placement of future wells, we used an approach combining geospatial analysis and maximum entropy (Maxent) modeling. This approach is commonly used in ecological sciences to predict the most probable distribution of species based on the environmental conditions of their known habitat [11-13]. This approach has also been used previously to predict the location of future well pad sites in Pennsylvania's Marcellus Shale play [14] to assess the impacts of habitat disturbance. We expand the use of this model here to the entire Interior Marcellus Shale region to project where natural gas development may occur at full development of the shale play.

Model Variables

For this research, we used geographic information system (GIS) tools (Environmental Systems Research Institute [ESRI] ArcGIS 10.2) to process a variety of environmental variable layers that are known to be relevant in the siting of natural gas well pads [15]. These layers are based on the best available data and include characteristics of the shale, itself, and characteristics of the states' landscapes, such as the terrain and infrastructure:

- **Shale characteristics** provide insight into the amount of natural gas that may be present. The layers depicting the depth and thickness of the Marcellus Shale we used for this analysis were developed by the Penn State Marcellus Center for Outreach and Research [16]. Shale thermal maturity was based on the work of Wrightstone [15] and was obtained from Rystad Energy [17].

- **Land cover and slope variables**, which outline the terrain of the region, can help to gauge the relative effort required when developing a well pad. We used the National Land Cover Dataset (NLCD) [18] as the land cover variable layer. We created the slope layer from the USGS 30-meter national elevation dataset [19] using the "Slope" tool in ArcGIS.

- **Distance variables** represent the importance of a well pad's proximity to critical infrastructure that supports the extraction process. We used geospatial pipeline data from IHS Energy [20] and geospatial road data (primary and secondary roads only) from the U.S. Census Bureau [21] to represent infrastructure. We then used the Distance tools in ArcGIS to create the distance variable layers.

All layers were sampled to 30 meters and formatted for the Maxent application by using the "Extract by Mask" tool in ArcGIS to align all layers to the Interior Marcellus boundary.

We used the coordinates for wells drilled in the Marcellus Shale between 2005 and 2013 (from Rystad Energy [17]) as inputs for the model, amounting to about 8,000 well locations. We then used the well locations to estimate the number of unique well pad locations as inputs for the Maxent model, since multiple wells can be drilled on a single well pad. We accomplished this by placing a 50-meter buffer around each well and taking the center point of any overlapping buffers as the pad location, resulting in approximately 3,600 unique pad locations.

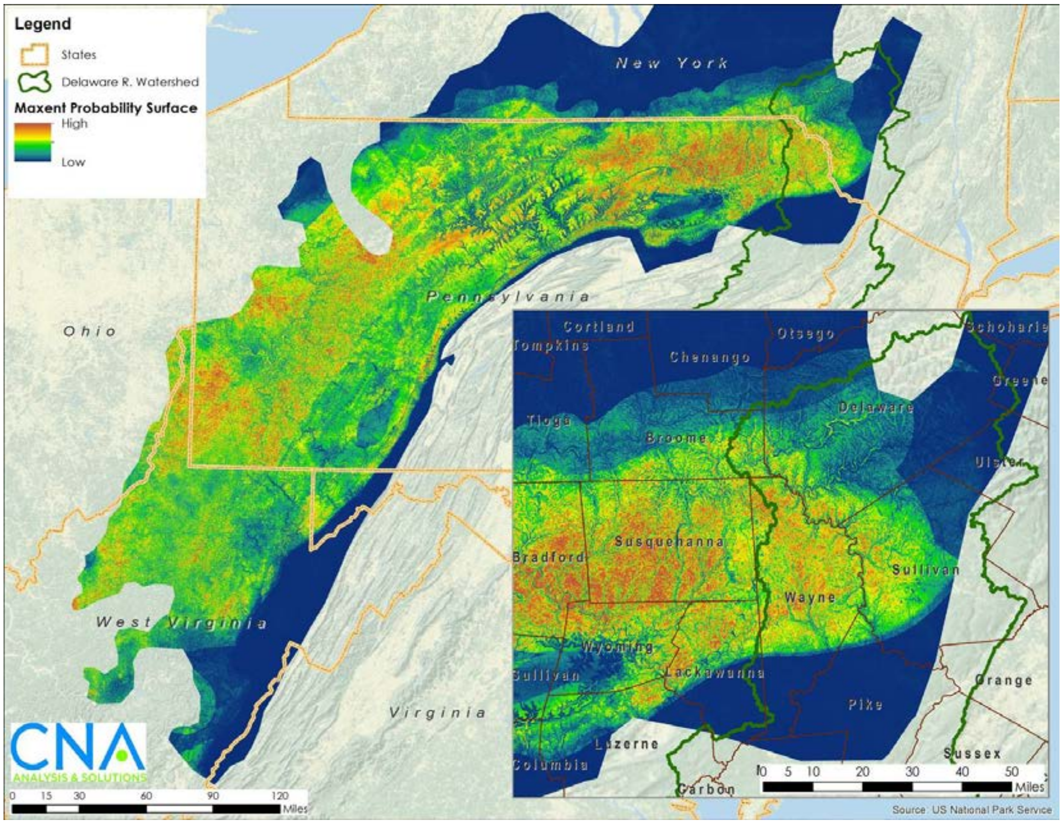
Well-Location Modeling

We input the well pad locations and environmental layers into the Maxent modeling application (Version 3.3.3k [22]) to evaluate the layer values at each of the locations. Maxent uses the characteristics of the environmental layers at existing well locations to develop a scoring model, which translates these layer characteristics into a probability model for future locations. From the 3,600 locations that we input into the program, about 2,900 were randomly chosen to build the model; the remaining locations were used to validate the model. The program produced a probability surface that depicted the most probable locations for well pads. We analyzed the probability surface using ArcGIS to evaluate the extent of potential natural gas development in the region.

To begin the study, we examined the full extent of the Interior Marcellus. There are other shale plays in the region, but we did not consider them in this analysis. Figure 2 shows the probability surface generated by the Maxent program. This analysis is based on physical parameters only and assumes no regulatory or economic constraints. The surface has 30-meter resolution and uses a color scheme to depict the suitability of the region for development based on the environmental variables, with “cooler” colors denoting areas with a lower probability of development, and “warmer” colors denoting those with a higher probability of development. Evaluation of the surface shows two distinct areas with a concentrated high probability of development: one in the northeast region of Pennsylvania (around Tioga, Bradford, and Susquehanna Counties), and the other in the southwest region of the state (around the Pittsburgh area). These two areas are consistent with a majority of the shale gas development seen in the region.

The probability surface also shows potential in Wayne County in northeast Pennsylvania, as well as some parts of Broome, Delaware, and Sullivan Counties in New York along the NY–PA border. No development has occurred in these areas, as they are under moratoriums put in place by the DRBC and New York State. Following examination of the full probability surface, we focused on these areas of the Interior Marcellus Shale that fall within the Delaware River Basin (Figure 2, inset).

Figure 2. Map depicting the Maxent probability surface for the Interior Marcellus Shale. The northeastern and the southwestern parts of Pennsylvania have the highest probability of future development. Some drilling could occur within the Delaware River Basin if the moratoriums were lifted.



Source: U.S. National Park Service (Terrain Basemap)

Development Scenarios

To determine the number of wells that would be needed to fully develop the Marcellus Shale, we used the U.S. Energy Information Administration's (EIA's) estimate [10] of technically recoverable resources: 113.9 trillion cubic feet for the Interior Marcellus, divided by the EIA average total production per well (Estimated Ultimate Recovery [EUR] of 1.6 billion cubic feet [Bcf] per well). We subtracted the number of existing Marcellus wells from this total to get the number of new wells expected, which is over 63,000. We then developed two scenarios to model how well pads may be developed throughout the region to accommodate these new wells. The scenario names, referring to well pad distribution across the landscape, are as follows:

- **Dispersed:** Development of four wells per pad (more well pads built)
- **Concentrated:** Development of eight wells per pad (fewer well pads built)

Table 2 shows the number of well pads associated with each scenario. For this research, we assumed that new well pads would be built to accommodate each new set of wells. These scenarios and estimates are in line with trends in the industry. Currently, Marcellus Shale well pads average a bit less than three wells, though the trend in this region is toward more wells per pad, and there have been pads here with up to 19 wells drilled. These scenarios likely bracket the expected range of average wells per pad in the future.

Table 2. Scenarios used to project well pad development in the Marcellus Shale. Each scenario has the same number of wells, but the "concentrated" scenario has half as many well pads and twice the spacing between the pads.

Scenario	Total Wells	Wells Per Pad	Well Pads	Spacing[a]
Dispersed	63,412	4	15,853	367 acres
Concentrated	63,412	8	7,926	735 acres

[a] Spacing was based on an estimated drainage area for each well pad and calculated by extending half of the well laterals in one direction, and the other half 180 degrees in the opposite direction. We assumed a 4,000-foot lateral length and 500 feet of spacing between laterals.

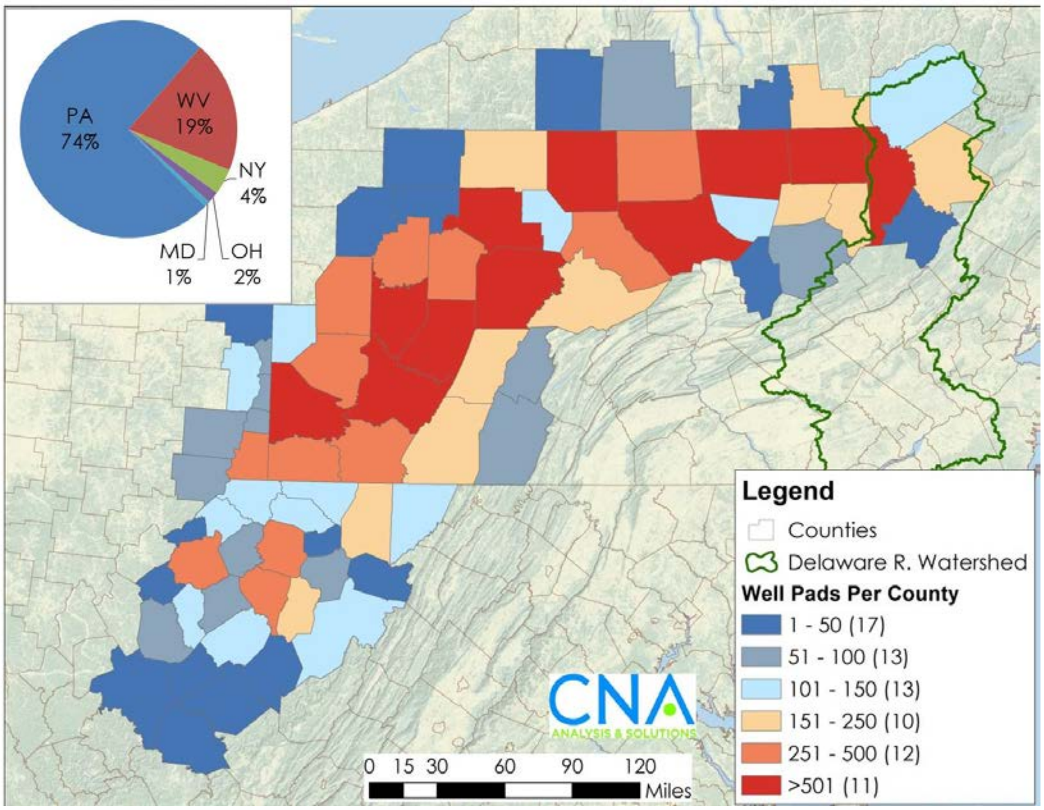
After developing the probability surface and scenarios, we devised a methodology to analyze the probability surface and choose the most likely locations for natural gas well pads. First, we used GIS tools to exclude areas in the probability map that would most likely be prohibited from development (e.g., existing well pad locations, wetlands, flood plains, and additional areas based on setbacks from streams, reservoirs, and buildings).

Next, we used a combination of spatial averaging and exclusion techniques in ArcGIS to ensure that well pads were sited over "hotspots" on the Maxent surface, and that well pads had adequate spacing (see Table 2) to prevent overlapping laterals. When completed, this analysis produced a distribution of unique cells on the Maxent best suited to well pads across the Marcellus Shale. For example, for the "dispersed" scenario, we selected the top 15,853 well pad locations as measured by Maxent values. These locations were converted to a set of points representing well pad locations across the Marcellus Shale that could be used for further analysis. By focusing on the locations within the DRB, we can begin to understand the scope of shale gas development if the moratoriums were lifted.

Based on the "dispersed" scenario, Figure 3 shows a breakdown of the number of well pads projected from future development in each county throughout the

Marcellus Shale. The inset for this figure also shows the aggregate percent total of well pads expected in each state overlaying the Marcellus. As expected, we see a majority of potential future development (74 percent) occurring in Pennsylvania, based on both the favorable conditions for development and the fact that a majority of the Marcellus Shale is found under the state. Furthermore, all 11 of the highest developed counties (>500 well pads) are located within Pennsylvania. The highest number of wells we found in a county is about 2,900 in Washington County.

Figure 3. Map depicting the number of *new* well pads that could be developed in each county based on the "dispersed" scenario (15,853) if fracking were allowed across the whole Marcellus. Inset shows the breakdown of new well pads by state. Eleven counties in Pennsylvania are likely to experience the most shale gas development, including Wayne County, PA, in the DRB.



Source: U.S. National Park Service (Terrain Basemap)

Results and Study Area Selection

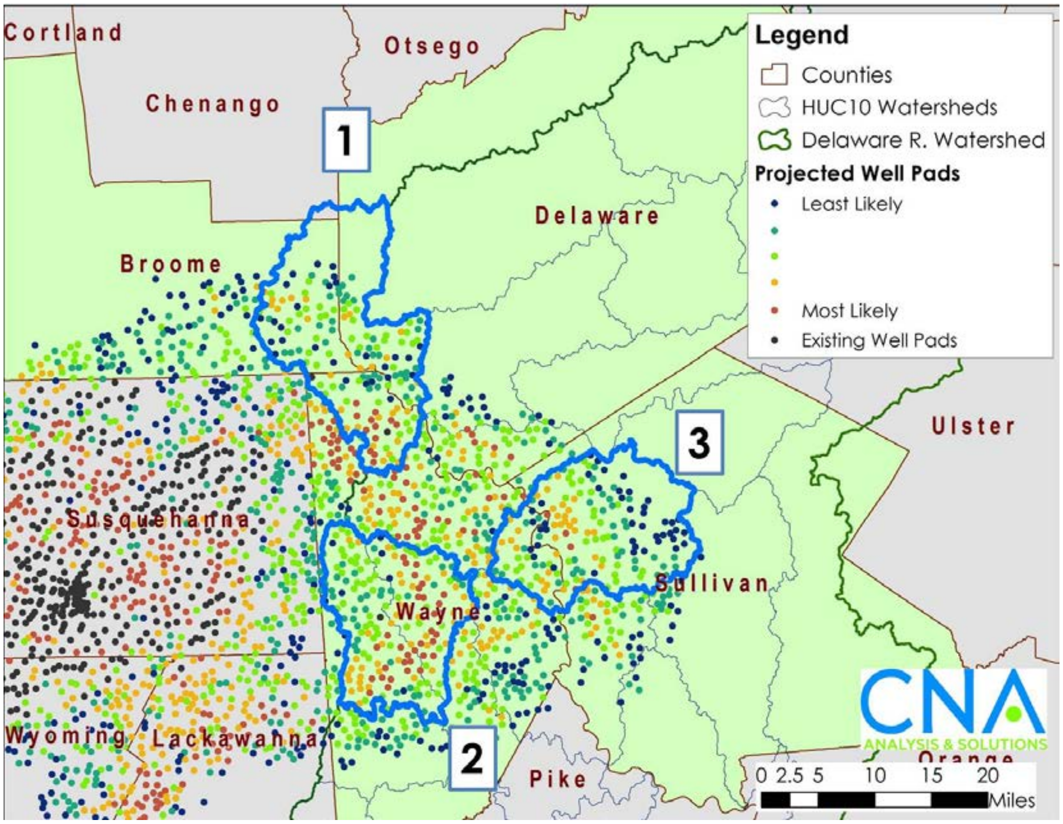
Figure 4 shows an expanded view of the potential landscape of natural gas development in the DRB, based on our development projection using the "dispersed" scenario. The well pads are color-coded according to their potential for development, again using the warm-to-cool scale to indicate most to least likely. Based on this modeling, the DRB potentially could see 500 ("concentrated" scenario) to 1,000 ("dispersed" scenario) well pads (or about 4,000 wells) developed were the moratoriums to be lifted. In either scenario, we expect that a majority of the development within the DRB would occur in Wayne County, PA.

We chose three study areas within the DRB to localize our assessment of potential water-related impacts to the environment. Each study area is based on the USGS hydrologic unit code (HUC)–10 watershed boundaries and is approximately 160–210 square miles in size. (For reference, the city limits of Philadelphia cover an area of 143 square miles.) The study areas are highlighted in Figure 4 and cover areas in both New York and Pennsylvania that would most likely be impacted by development. We will reference these study areas throughout the following chapters when evaluating each of the different impacts. Study Area 1 includes portions of Broome (NY), Delaware (NY), and Wayne Counties (PA), and is just downstream of the Cannonsville Dam. Study Area 2 includes two adjacent HUC-10s in Wayne County. Study Area 3 is primarily in Sullivan County, NY.[1]

[1] The USGS 10-digit Hydrologic Unit Codes for these areas are as follows:

Study Area 1 – 0204010103; Study Area 2 – 0204010301 and 0204010302; Study Area 3 – 0204010105.

Figure 4. Potential locations for new well pads in the DRB, based on the "dispersed" scenario. We chose from three study areas (blue outline) or four counties (green fill) as assessment units for further analysis.



For each of the following chapters, we chose assessment units (i.e., drainage areas or counties) best suited to quantify and describe the extent of impacts that may be expected (see Table 1). For land- and water-related impacts, we used the drainage areas of defined subwatersheds in the DRB. For impacts to air quality and human health, we used county boundaries. Table 3 shows the extent of natural gas development in the DRB that our methodology projects, broken down by these different assessment units for reference throughout the report.

Table 3. Projected natural gas development in the DRB, broken down by development scenario and assessment units. Of the four impacted counties in the DRB, Wayne County, PA is projected to experience the most development.

Assessment Unit	Area (sq mi)	Dispersed Scenario Well Pads	Dispersed Scenario Wells	Concentrated Scenario Well Pads	Concentrated Scenario Wells
Study Area 1	212	162	648	90	720
Study Area 2	162	191	764	93	744
Study Area 3	178	170	680	79	632
Wayne Co., PA[a]	751	590	2,360	303	2,424
Broome Co., NY[a]	715	58	232	34	272
Delaware Co., NY	1,468	204	816	93	744
Sullivan Co., NY	997	123	492	67	536
DRB Total	3,150[b]	975	3,900	497	3,976

[a] These numbers reflect only the portion of expected development that would fall within the DRB; Wayne Co., PA, and Broome Co., NY, could see development outside of the DRB.

[b] This area represents the portion of the DRB that lies above the Interior Marcellus. Roughly one-third of this area has projected well pad development.

Discussion

Our results depict a model of potential development in the Interior Marcellus Shale—and particularly in the DRB—assuming full exploitation of the Shale's technically recoverable resources (as estimated by the EIA). Our goal with this model was to provide a projection and spatial context to this development in order to evaluate what environmental impacts it could have on the basin (assuming drilling was allowed to proceed). Given the importance of shale characteristics to the model, the use of additional variables (e.g., total organic carbon, or the inclusion of potentially more-accurate proprietary data) could lead to a different projection.

We estimate that about 4,000 wells could be drilled in the Marcellus Shale within the DRB. This projection falls within a wide range of other published and unpublished estimates of well development in this region. For example, the National Park Service used the overlap of the Marcellus Shale and DRB boundaries with some spacing and exclusion assumptions to arrive at an estimate of 16,000 to 32,000 wells that could be drilled in the DRB [23]. Kaufman and Homsey estimated the amount of gas that could be produced in the DRB by using estimates of reserves and excluding lands based on proposed regulations to assess the economic value of shale gas development in the region [24]. Their results indicate an estimate of approximately 2,500 wells drilled in the DRB (based on their production estimates for the DRB and applying our assumption that wells have an EUR of 1.6 Bcf), a number in fair agreement with our projections. The Nature Conservancy used a similar methodology to ours to project the location of potential wells in Pennsylvania, which we estimate from their report includes approximately 350 wells drilled in Wayne County, PA [14]. While this estimate is noticeably lower than ours (we project approximately 2,600 wells in Wayne County), the authors did add a caveat that their results may have underestimated Wayne County, based on comments from reviewers. Berman and Pittinger recently estimated potential development in New York based on well production data in Pennsylvania [25]. Their results indicate that although Broome County could see the most development in New York, this development would be focused mostly on the western to central portion of the county, with little apparent development in the DRB portion. The study also estimates no development in Delaware and Sullivan Counties (NY), in contrast with our results. The authors do state that the lack of well-production data in New York (due to the moratorium) does add uncertainty to this area. These studies demonstrate the variation in potential for well development in the region, and the results of our study fall within the range of well development that the previous studies have found .

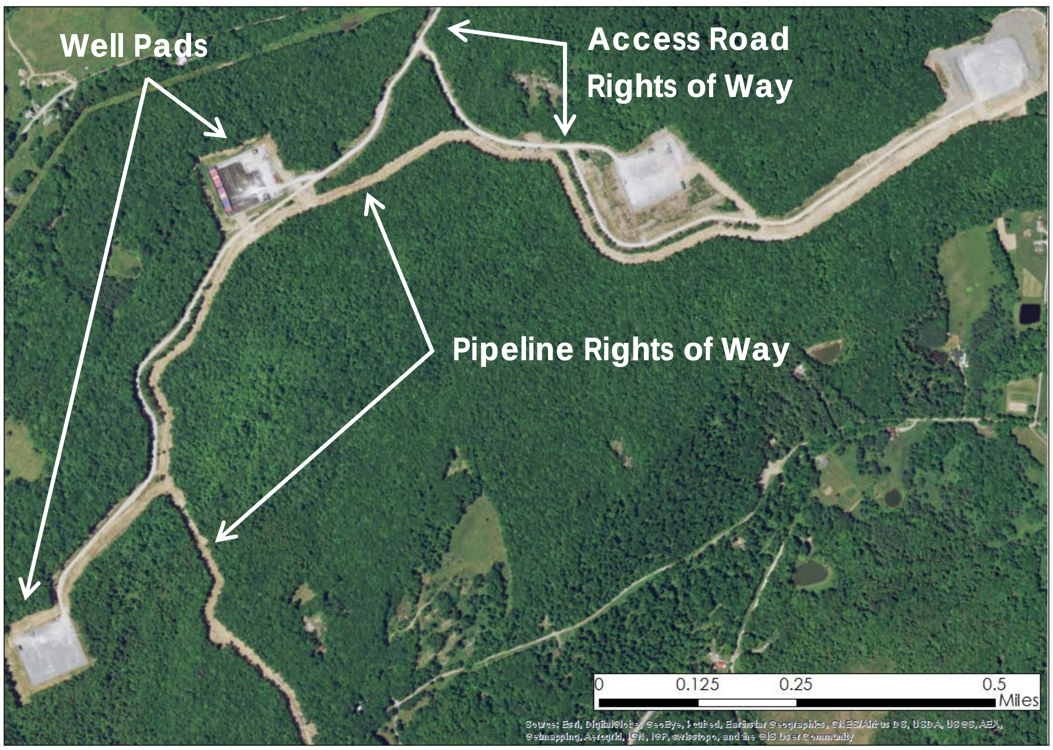
Impacts on Land Cover

Key Findings

- We analyzed land cover changes in three study watersheds with extensive projected gas development. Land converted for each well pad, including the pad itself, access roads and the rights-of-way for gathering pipelines, would directly impact 17-23 acres per well pad. Gathering pipelines account for 75 percent of this area.
- Gas infrastructure could directly convert 2–3 percent of the land in areas affected by fracking, with most of the impacted area made up of agricultural land and forests.
- Shale gas development could lead to a 1–2 percent loss of total forest land in impacted DRB watersheds that we studied, and between 5 and 10-percent loss of core forest.
- The total area of land disturbed in the DRB at the completion of gas development in the Interior Marcellus could be 18 – 26 square miles. This is about the same area as 570 to 840 Wal-Mart Supercenters including their parking lots.

When assessing the environmental impacts of natural gas development, one of the most unavoidable aspects of such development is the impact to land cover. A typical well pad may cover 3–5 acres of land to support the fracking process, which includes the well site, itself, and room for supporting equipment, such as drilling equipment, water impoundments, quarries, temporary construction areas, and truck parking [2, 14, 26]. The well pad site is typically cleared of any previous land cover to produce a barren surface to support the extraction activities. In addition to the well pad, development of land to support natural gas extraction requires access roads to the site and gathering or feeder pipelines to transport the extracted gas from the site to the existing transmission infrastructure [27-30]. Figure 5 shows an example of this development in Susquehanna County, PA. Development of this supporting infrastructure requires clearing land not only for the infrastructure, itself, but also for the accompanying right-of-way to accommodate construction equipment and future maintenance. The resulting land disturbance from this development can present both short- and long-term risks to the use of the land, depending on the remediation and reclamation procedures used [26, 31]. Furthermore, the design and practices used by pipelines and roads to cross streams and wetlands can adversely impact the health of these ecosystems by altering channel geomorphology and restricting the movement of fish and wildlife [32-33].

Figure 5. Imagery depicting several existing well pads and associated infrastructure rights-of-way in Susquehanna County, PA. This provides an example of the potential footprint associated with natural gas development.



Source: ESRI World Imagery Layer from ArcGIS Online (ESRI, DigitalGlobe, GeoEye, i-cubed, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community)

One particular issue associated with the development activities from natural gas extraction in the Marcellus Shale is the impact on forests [14, 27-28, 31]. The portion of the DRB that lies above the Marcellus Shale includes over two million acres of forest, and forested land is the dominant land cover in each of our three study areas (approximately 65,000–110,000 acres each, which is more than 50 percent of each study area). This dense forest cover provides the region with a variety of ecosystem services, such as carbon sequestration, clean air, aquifer recharge, and recreation/eco-tourism. These services are in addition to the key role that forests play in maintaining the water quality of the Delaware River, which supplies drinking water to over 17 million people [24].

Furthermore, forest cover in the region is home to a variety of different plant and animal species that rely on the forest for their habitat. Forest habitats are divided into two primary classes: edge and core forest. Edge forest is generally described as the area that is adjacent to the non-forest area, extending inward approximately 300 feet (or 100 meters) [27-28]. The edge transition from non-forest to forest area creates a habitat that tends to favor generalist species over rare or vulnerable species, and an increase of edge forest can promote the spread of invasive species [31].

To assess the potential land cover impacts on the DRB from natural gas development, we combined our above projections of natural gas development in the watershed with a suite of GIS tools and methodology. We first used least-cost path-optimization to model the extent of potential infrastructure (gathering pipelines and access roads) that could be developed to support these well pads in the DRB. We did not account for additional potential construction that could occur to support natural gas development (e.g., new transmission pipelines or compressor stations), which was beyond the scope of this study. We then performed a buffer analysis using the projected well pad locations and supporting infrastructure to survey the impacts to current land cover (and further the potential for forest fragmentation) that could be expected from development in these areas. Finally, we compared the projected land cover impacts to other recognizable development activities to provide context to the scale of these impacts.

Methodology

To model the infrastructure required to support our projections of natural gas development, we used the least cost path optimization approach, which is a common approach for siting and analyzing roads and pipelines. To perform this modeling, we first developed a cost surface for each study area by combining a variety of geospatial layers relevant to routing, and assigning a cost to the values associated with each layer. “Cost” in this sense refers to a penalty for following a less-efficient route, and we assigned costs to the layers based primarily on the ESRI Pipeline Optimization Route Interface [34], with additional input from industry methods and reports [35-37]. These layers covered a variety of factors that can impact infrastructure route design, such as topography, affected population, and environmentally sensitive areas. For example, we assigned a higher cost for development on terrain with steep slopes, compared to relatively flat areas. We used this cost surface with the "Least Cost Path" tool in ArcGIS to determine the most efficient route from the projected well pads to the existing infrastructure.

The construction of well pads, gathering pipelines, and access roads to support natural gas extraction requires the clearing of land to accommodate this infrastructure. To assess both the area and type of land that may be disturbed from these activities, we used GIS tools to map the spatial extent of the well pads and associated infrastructure. We estimated that each well pad occupies 3.5 acres, each pipeline requires a 30-meter right-of-way, and each road requires a 15-meter right-of-way, based on studies that examined aerial imagery depicting areas with shale gas development [14, 29-30]. We used these values to buffer the appropriate features to create the spatial footprint of development in each study area. We then used this footprint to extract the impacted land values from the NLCD. Furthermore, to determine the number of stream and wetland crossings that could occur from pipeline and road development, we used the "Intersect" tool in ArcGIS to count the number of intersections between the new infrastructure and the stream and wetland networks in each of the study areas.

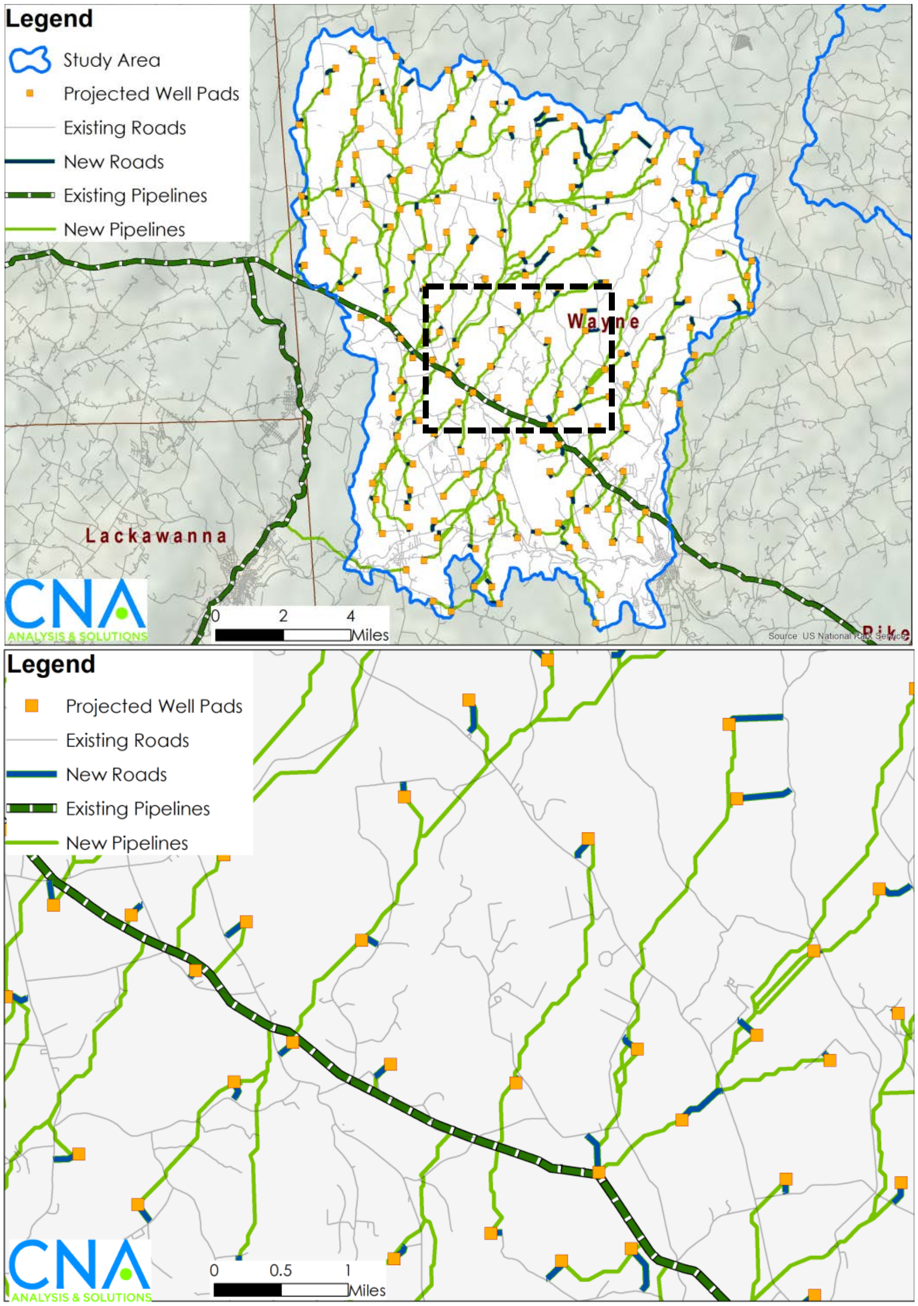
Given the prevalence of forest cover in the DRB and the potential for impact, we extended our land cover analysis to focus on the extent of forest fragmentation caused by this disturbance. To assess this impact, we calculated the baseline total area of forest in each study area through GIS analysis of the NLCD. We updated this dataset with rights-of-way from the existing road, pipeline, and rail networks to more accurately depict the baseline condition. To calculate core forest, we used GIS tools to generate a 100-meter buffer into the baseline forest from the edges. We refer to this 100-meter buffer as "edge forest." After we generated the baseline condition, we assessed the potential impact from natural gas development by applying the same spatial footprint as above. We then generated a 100-meter buffer into the forest from all new forest edges (i.e., from well pads and along the road and pipeline rights-of-way) to represent the changes in core and edge forest.

Results

Infrastructure Modeling

Using least-cost path-optimization, we modeled the gathering pipelines and access roads that could be expected to support the new well pads in the three study areas. Figure 6 shows an example of these results from Study Area 2 ("dispersed" scenario), and Table 4 lists the results of all modeling. Note that these projections are intended to illustrate the potential scale of infrastructure with a reasonable estimation of spatial extent and are not meant to predict exact locations.

Figure 6. Projected gathering pipeline and access road development in Study Area 2 to support 191 well pads under the "dispersed" scenario. The installation of new gathering pipelines would be the primary driver of land disturbance from natural gas development.



Source: National Park Service (background)

Table 4. Projected infrastructure (gathering pipelines and access roads) needed to support natural gas development in the three study areas. Units = miles.

			Pipelines		Roads	
Scenario	Study Area	Well Pads	Total Length	Avg. Length Per Pad	Total Length	Avg. Length Per Pad
Dispersed	1	162	184	1.13	30.8	0.19
	2	191	235	1.23	35.6	0.19
	3	170	250	1.47	25.0	0.15
Concentrated	1	90	130	1.44	21.3	0.24
	2	93	163	1.75	20.5	0.22
	3	79	162	2.05	12.1	0.15

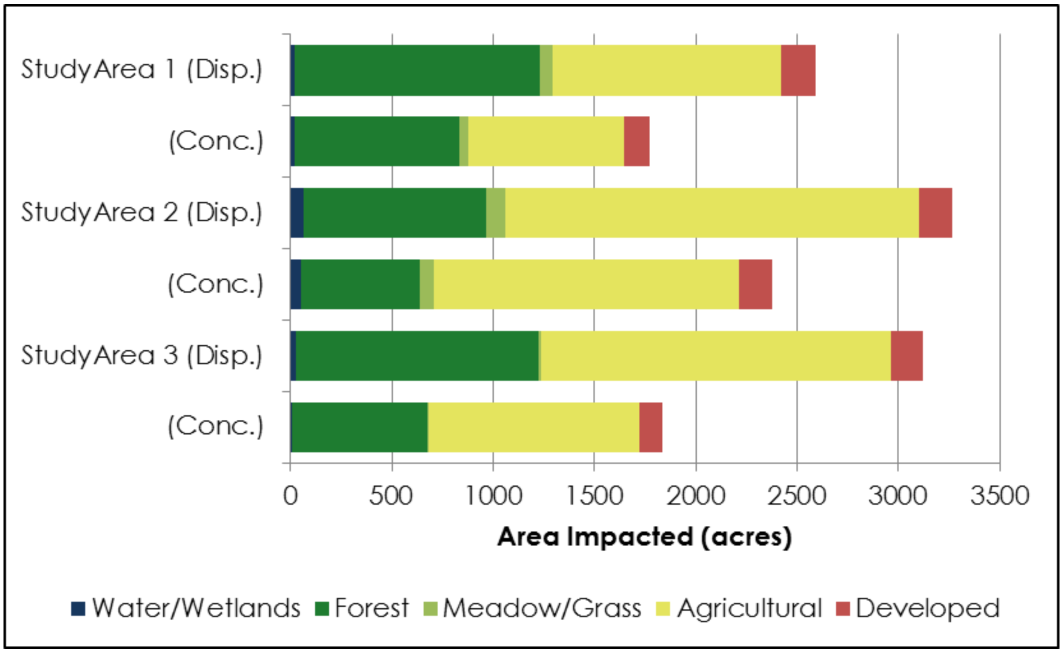
Our infrastructure modeling results compare favorably to recent retrospective studies on Marcellus Shale infrastructure development in Bradford County, PA [29-30]. For pipelines, the average length to support a well pad dropped by 26 percent from the “concentrated” to “dispersed” scenarios, which may be attributed to the location of the existing pipelines within the study areas and the relative spread of well pad locations. The well pad locations under the “concentrated” scenario are already spread out across the study areas, so many of the longest pipelines were modeled in this scenario, and the addition of more well pads under the “dispersed” scenario served to fill in the area. The average length of road developed per well pad was fairly consistent, at about 0.2 miles per pad among the study areas and scenarios, likely owing to the network of road infrastructure already in place throughout the study areas.

Land Cover Disturbance

Using our projections of potential well pads and supporting infrastructure within the DRB, we assessed the extent and form of land disturbance that would be observed from natural gas development. Figure 7 shows the breakdown of impacted land for each study area from natural gas development under the two build-out scenarios.

We project that each study area could see between 2,500 and 3,300 acres of impacted area in the “dispersed” scenario, and between 1,700 and 2,400 acres of impacted area in the “concentrated” scenario at well build-out. On average, these impacts represent 2 to 3 percent of the land area of the study areas. Although a large majority of the baseline land cover (more than 59 percent) in each study area is classified as forest cover, only Study Area 1 shows forest cover as the most impacted land area (and, even then, only slightly more impacted than agricultural land). This finding most likely is due to the higher cost associated with developing forest land versus agricultural land based on the method that we used to model infrastructure. However, a significant amount (28–47 percent) of the impacted land in each study area is forested.

Figure 7. Breakdown of total potential land cover disturbance from natural gas development in each DRB study area, broken out by scenario ("dispersed" or "concentrated"). A majority of the impacted area in each study area is agricultural or forested.



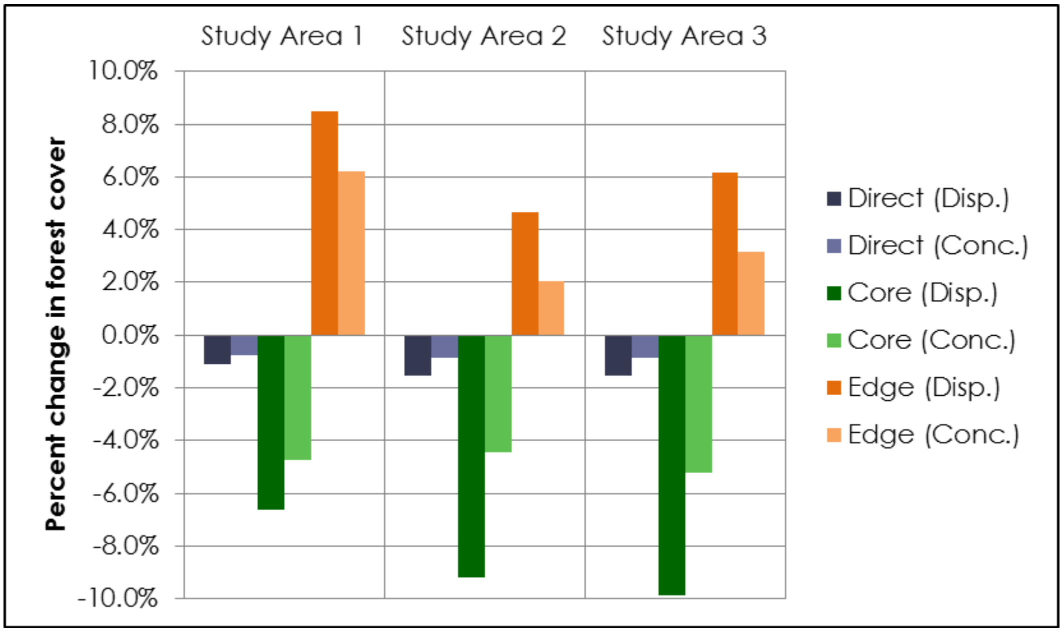
Our modeling revealed that a majority of the land disturbance associated with natural gas development would be attributed to gathering pipeline development (74 percent of the impacted land was due to new pipelines, versus 21 percent from well pads and 5 percent from new roads). This makes sense, considering that each new well pad would average 1.28 ("dispersed" scenario) to 1.75 ("concentrated" scenario) miles of gathering pipeline development, which would directly impact about 15 to 21 acres of land, respectively, versus 3.5 acres for the well pad, itself. This result also explains why, even though the "concentrated" scenario contains only about half as many well pads as the "dispersed" scenario, the concentrated scenario shows closer to two-thirds as much land cover impact as the dispersed scenario.

We also determined the number of stream and wetland crossings that could be encountered from development of supporting infrastructure. From our GIS analysis, we found an average of 115 stream crossings and 130 wetland crossings from new pipelines in each study area, and an average of 12 stream and 10 wetland crossings from new roads in each study area. We generated these results using the "dispersed" scenario; the "concentrated" scenario resulted in about 30–40 percent fewer crossings, due to the reduction in total infrastructure needed to support fewer well pads.

Forest Fragmentation

The results of our land cover analysis showed that development of natural gas well pads and supporting infrastructure would directly impact the extensive forest cover present in the DRB. Deforestation activities can also present a variety of indirect impacts to a forest's ecosystem that extend beyond the actual trees that are cleared. To evaluate the extent of these additional impacts, we performed a second buffer analysis to represent the baseline and impacted core forest in each DRB study area. Figure 8 shows the results of this analysis.

Figure 8. Percent-change in forest cover and type (core vs. edge) from infrastructure development in the DRB study areas, broken out by scenario ("dispersed" and "concentrated"). Results show direct conversion of about 1-2 percent of total forest, and indirect effects (a shift from core to edge forest) of 4–10 percent.



From Figure 8, we see that site and infrastructure development can have significant impacts on the core forest of the DRB. In the "dispersed" scenario, we found that the total forest area cleared for this development amounts to a loss of about 1 to 2 percent for each study area. This same development could amount to upwards of almost 10-percent loss in core forest area. Note that this loss in core forest area comprises both forest that is cleared for infrastructure and the resulting conversion from core to edge forest along these rights-of-way (the latter results appearing as the net gain of edge forest in Figure 8).

Discussion

Our results showed that the construction of well pads and associated infrastructure to support shale gas development would have an impact on the land cover of the DRB, affecting primarily agricultural and forest lands. Our modeling of the natural gas infrastructure was based on a standard GIS approach to provide a representative picture of this development. Thus, just as was stated for our projected well pad locations, the projected infrastructure is used for calculating impacts, but should *not* be interpreted as explicit *predictions* of where this infrastructure will actually go. The actual locations could depend on additional site-specific factors, such as lease holds and applicable laws and regulations.

Our assessment of land disturbance only accounts for the well pad and rights-of-way for gathering pipelines and access roads to support those well pads. We did not account for additional construction that could occur to support natural gas development, such as new transmission pipelines that may be needed to help move gas to market, or new compressor stations to support gas transmission through the pipeline network. This construction could be expected to add to the footprint of development and cause additional land cover impacts to the area.

To provide context to the scale of the projected land cover disturbance from natural gas development, we compared the impacted land area to other large construction projects that have been completed in the region. The projected amount of land cleared for development in Study Area 2 could be comparable to building 58 King of Prussia Malls, which is one of the largest malls in the United States. The projected amount of land cleared for development in Study Area 3 could be comparable in area to building 155 Wal-Mart Supercenters with parking lots (about 20 acres each).

If we assume that land cover impact stays constant on a per well pad basis, we can roughly project the total land cover change for the entire DRB. Based on the average of the results for the three study areas, the total land cover impact is 17-23 acres, depending on the development scenario. Based on these per-well pad numbers, and the number of well pads projected in the DRB, we estimate the total area of DRB land cover change as between 18 and 26 square miles. This makes up 0.5 to 0.8 percent of the total Interior Marcellus area within the DRB (3150 square miles), but within the portion with well pad development projected (950 -1000 square miles), the total land cover conversion percentage should be roughly in line with the study area results at about 2 percent. Or, to use a prior example, the total land cover change would be equal in area to between 570 and 840 Wal-Mart Supercenters including parking lots.

Land-cover change from shale gas development is unavoidable, and disturbance can be significant at build-out. The loss of forest cover, in particular, can have significant impacts on the watershed, such as degraded water quality (for more details, see the "Impacts on Water Quality due to Changes in Land Cover" chapter of this report) and a loss of biodiversity from disappearing flora and fauna that cannot tolerate "edge effects." Furthermore, remediation procedures to restore vegetation on the impacted land often do not replace mature forest cover, in part because of the need to maintain access to gathering lines and use roads, and because mature forests take a long time to grow.

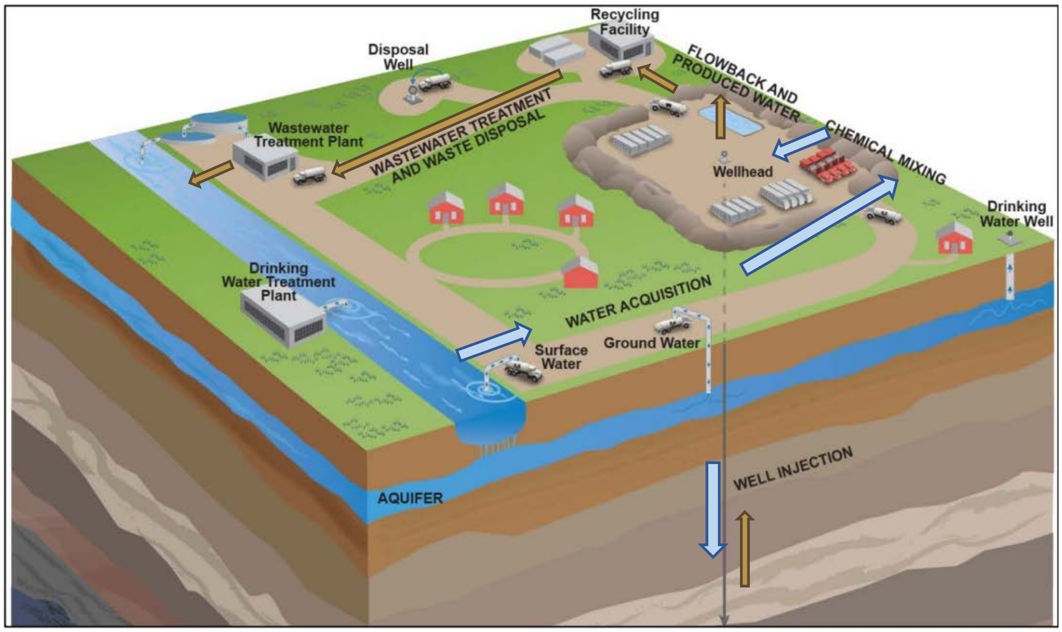
Impacts on Water and Wastewater Management

Key Findings

- Unconventional natural gas development requires about 4.5 million gallons per well, mostly to mix the "frac" fluid injected into the shale during hydraulic fracturing. Most of this water does not return from the shale after injection during the fracturing process and is a consumptive use.
- The impacts of water withdrawal on streamflow vary widely, depending on location, development rate, and flow conditions. During maximum periods of well development, the percentage reduction in streamflow ranges from over 70 percent during low-flow conditions to less than 3 percent during median or average flow conditions if withdrawals are taken from small streams.
- Natural gas wastewaters (flowback and brine) are concentrated, carrying high loads of dissolved solids, salts, some metals, hydrocarbons, and radioactive materials.
- If all wastewater were treated to meet Pennsylvania's effluent standards and discharged in the study areas, the amount effluent produced during maximum-development periods could raise in-stream concentrations of some contaminants (notably barium and strontium) up to 500 percent above background levels during low-flow conditions.

One of the principal ways that unconventional gas drilling differs from conventional gas drilling is in its use of water for the extraction process and the amount of wastewater produced. There are two primary water uses in the process (drilling fluids and "frac" fluid), and three primary types of wastewater generated (waste drilling fluid, "flowback," and brine wastewaters) that must be treated and either recycled or disposed. Figure 9 illustrates the flows of water and wastewater (WW) during the fracking and gas-extraction process.

Figure 9. The fracking water cycle. This cycle includes water acquisition (withdrawal), mixing into "frac" fluid, injection into the well, recovery of wastewater (flowback and produced water) from the well, wastewater reuse (recycling), and then wastewater treatment and disposal.



Source: Environmental Protection Agency [38]

Water plays a key role in hydraulic fracturing as the base of the frac fluids that are injected at high volume into the shale to fracture it and release tightly held gas. A smaller quantity of water is used for drilling the wells before fracking. The bulk of the water use is consumptive, because most the frac fluid remains in the ground (and wastewater is often reused or sent outside the basin for treatment).

The main wastewaters include drilling fluids recovered after drilling and frac fluid that returns from the shale after hydraulic fracturing. The drilling wastewater is often recycled and reused as new drilling fluids or is disposed (in injection wells, among other disposal methods). The flowback is composed primarily of frac fluid that returns back up the well bore due to the high pressures in the fractured shale in the 10–14 days (up to 30+ days) after fracking and before gas production. Following the flowback period, as the well is producing natural gas, a smaller amount of wastewater continues flowing along with the gas. This wastewater is composed mainly of frac fluid, but also picks up pollutants from the shale, notably salts, which earns it the name "brine" (also called "produced water"). After collecting flowback and brine, the wastewater can be reused in making new frac fluid, disposed via deep groundwater injection, or treated at special wastewater treatment plants.

Disposal of this flowback and brine wastewater is a significant concern due to the high concentrations of dissolved solids (mostly salts), metals, hydrocarbons, and radioactive materials [39]. Some particular contaminants of concern include ions such as chloride, sulfate, ammonium, and iodide; metals such as barium and strontium; solvents and aromatic hydrocarbons such as benzene and formaldehyde, and radioactive elements such as radium. Appendix A contains an expanded list of chemicals that have been detected in flowback and brine wastewaters, including approximate concentrations at which they are found. Even with treatment, concentrations of pollutants (especially dissolved solids, salts, and ammonium) in wastewater effluent have often been measured at concentrations exceeding water quality standards [40]. In addition to potentially harming aquatic life [41], some of these chemicals are difficult to remove in drinking water–treatment plants [42] and can lead to enhanced formation of disinfection byproducts [43-44] in drinking water, which can increase risk of some health effects (including cancer) [45]. Industrial wastewater treatment has improved since UNGD started in Pennsylvania, as have regulations that now limit Total Dissolved Solids (TDS) effluent concentrations to 500 mg/L, equivalent to current DRBC discharge regulations [46], yet these limits are many times higher than existing water quality in the basin's special protection waters (50–100 mg/L TDS) [47].

The rest of this chapter investigates the impacts of the hydraulic fracturing water cycle for both water and wastewater. First, we computed the volumes of water and wastewater for the study areas, and we examined the withdrawal rates in the context of the available streamflow. The second portion of the results focuses on the pollutant loadings in the hydraulic fracturing wastewater, which we contextualize with the ambient loadings of these pollutants carried by the nearby streams.

Methodology

UNGD water and wastewater processes are linked, though their environmental impacts are manifested rather differently. In this analysis, we compute a median estimate of water use and wastewater production on a per-well basis, and then multiply by the number of projected wells for each case study area to determine the volumes of water withdrawals needed and wastewater generated in each. We estimate water usage; wastewater generation and recovery; and reuse rates from publicly available databases and peer-reviewed literature. Since the "concentrated" and "dispersed" scenarios result in a similar number of wells developed, we consider only the "concentrated" scenario in this chapter (as it has slightly more wells).

To estimate the impact of the water acquisition, we compare the withdrawal to available freshwater flow in the study areas. The water-related impacts are more easily judged using expected flow rates than overall volume. Well development is not likely to occur at a constant rate, and impacts are magnified during periods of rapid development, so we considered two scenarios to explore the range of impact the well development rate may have on water availability:

- **Average Development Year:** Assumes that development occurs at a constant rate over a 30-year build-out.

- **Maximum Development Year:** Assumes that 20 percent of well development build-out in each study area occurs in one year.[2]

The average- and maximum-year scenarios show the range in flow rates for water withdrawal and wastewater generation—and, by extension, the watershed impacts.

To estimate wastewater impacts, we investigated how discharge of treated wastewater effluent according to Pennsylvania regulations would raise concentrations of five key pollutants in streams. We only consider the flowback and brine wastewaters, as the drilling fluids and cuttings are generally disposed as solid waste. We multiplied the wastewater flow rates by concentrations of pollutants reported in the literature to calculate pollutant loads. The total loading rate of contaminants of concern in the various types of wastewater (flowback and brine) is estimated after treatment of wastewater (i.e., in wastewater treatment effluent), and for cases with and without reuse of wastewater.

Using local streamflow statistics, we developed an initial estimate of how much these loadings would raise concentrations of five key pollutants in the runoff coming from each study area, and compared this change to reference concentrations in the basin. Since these estimates lack the context of actual location and method of treatment, and cover a limited set of pollutants, we recommend future studies with more specific scenarios. Furthermore, this study considers only the most likely pollutant pathway (wastewater effluent) for water quality impacts [5], but other pathways such as spills from trucks or at the drilling site may have impacts [5, 49-50], though often at more localized scales.

[2] The maximum-year scenario represents an estimate of maximum development that may occur in one study area. Based on observations of Baker Hughes rig count data [48], the maximum rig densities appear to be about one rig per 20 square miles, or 6–10 per study area. If we assume an average completion time of 20 days for wells, then rigs may be able to drill 18 wells per year. This would be sufficient to drill about 20 percent of the wells in a study area. For consistency, we applied this 20-percent assumption to all of the study areas.

Results

Water Use and Wastewater Generated

Water needs and wastewater generation are significant for natural gas operations, but must be properly compared to overall water availability and put into context by existing water uses in the DRB. Figure 10 shows the average per-well volumes of water and wastewater expected for projected well development in the DRB.

Reuse of drilling fluid, flowback, and brine plays an important role in reducing both freshwater demand and the volume of wastewater that must be disposed. After accounting for reuse, the remaining freshwater withdrawal and wastewater disposal volumes are the most important metrics for planning.

Figure 10. Sankey diagram of water volumes for the fracking water and wastewater management cycle estimated for this study, on a per well basis. "Frac" fluid dominates water use, and most is not recovered. Units = million gallons per well.

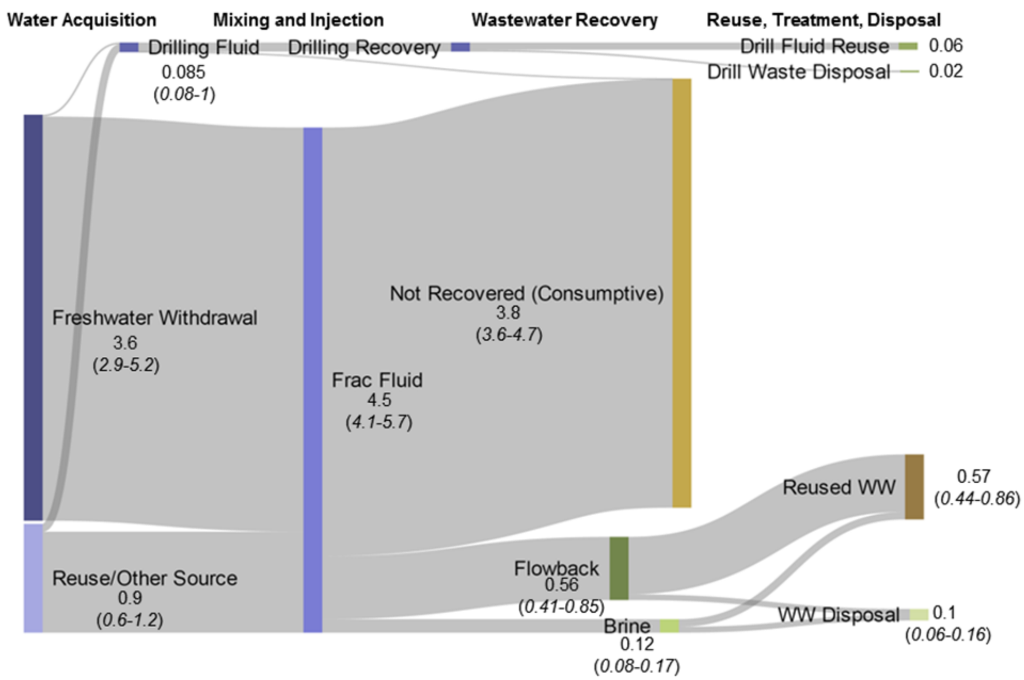


Figure by CNA via *SankeyMATIC*

[a] Numbers show expected value. Expected range in parentheses.

We estimated water use based on FracFocus database records [51] of frac fluid water use per well across the Marcellus Shale. We calculated the per-well average water use based on 2012 and 2013 data for six counties in northeast Pennsylvania (Bradford, Lycoming, Sullivan, Susquehanna, Tioga, and Wyoming). The range represents the highest and lowest county average. Adding the water use for drilling fluid (about 85,000 gallons [52-53]), we compute the average water demand at 4.5 million gallons per well. Mantell estimated that alternative sources (such as recycling and reuse of flowback) reduce freshwater needs by 10–30 percent [52], and we assumed a median of 20 percent. We assumed that this reused water could come from reuse of flowback and brine within the study area or other sources (e.g., wastewater treatment plant effluent, groundwater, or purchases from public supply) within the DRB.

Flowback wastewater is generated at a rate of 10–15 percent of the volume of frac fluid injected [53-55], while brine production is about 50–100 million gallons per million cubic feet of gas produced [52]. The reuse rates of these wastewaters based on current industry practices are estimated to be about 90–95 percent for flowback and 56 percent for brine [53]. Though we do not include indirect uses in our analysis, Jiang et al. [53] estimated that indirect water consumption for well pad preparation might account for an additional 0.5 million gallons of water per well, and total indirect uses might account for as much as 2 million gallons per well.

Table 5 displays average daily rates of water use, withdrawal, wastewater generation, and wastewater effluent disposal for each study area, based on the per-well factors in Figure 10 and the number of wells developed. Note that the DRB total at the bottom includes wells not in the three study areas.

We account for reuse of wastewater (based on literature values of recent industry averages) in two ways. "Withdrawal" reflects remaining freshwater need after accounting for reuse and alternate sourcing. "Wastewater Generated" includes all flowback and brine recovered, but "Effluent Disposal" includes only the remaining portion of wastewater that is sent for treatment at industrial wastewater treatment facilities. We assume that the disposal volume is treated at wastewater treatment plants in the basin (instead of disposed through deep well injection or transported outside the basin), so this "disposal" volume can be called wastewater "effluent." To establish the full potential range of impacts, we also consider the case where all wastewater is treated and disposed later in this chapter (i.e. no reuse).

Table 5. Projected rates of well development, water use, withdrawal, wastewater generation, and effluent for disposal, by study area and scenario. Units = 1,000 gallons per day, except wells per year.

Study Area	Scenario	Wells Per Year	Water Use	Withdrawal (Freshwater)	Wastewater Generated	Effluent Disposal
1	Average	22	270	210	40	6
2	Average	25	320	250	50	7
3	Average	23	280	230	50	6
1	Max.-Year	130	1,610	2,570	270	36
2	Max.-Year	153	1,900	3,040	320	43
3	Max.-Year	136	1,690	2,700	280	38
DRB	Average	133	1,650	1,320	270	37

Since water withdrawals are often not constant over a development period, we developed a reasonably high-withdrawal scenario. In the maximum–year scenario (20 percent of wells developed), we further assumed that water withdrawal occurs over a limited time window during the well-development process, equal to half of the well completion time (roughly 20 days). This doubles the effective withdrawal rate because the same amount of water is collected over 50 percent fewer days. Actual peak withdrawal rates could be higher if the water needed for each well fracturing is collected in only a few days to minimize water storage time onsite.

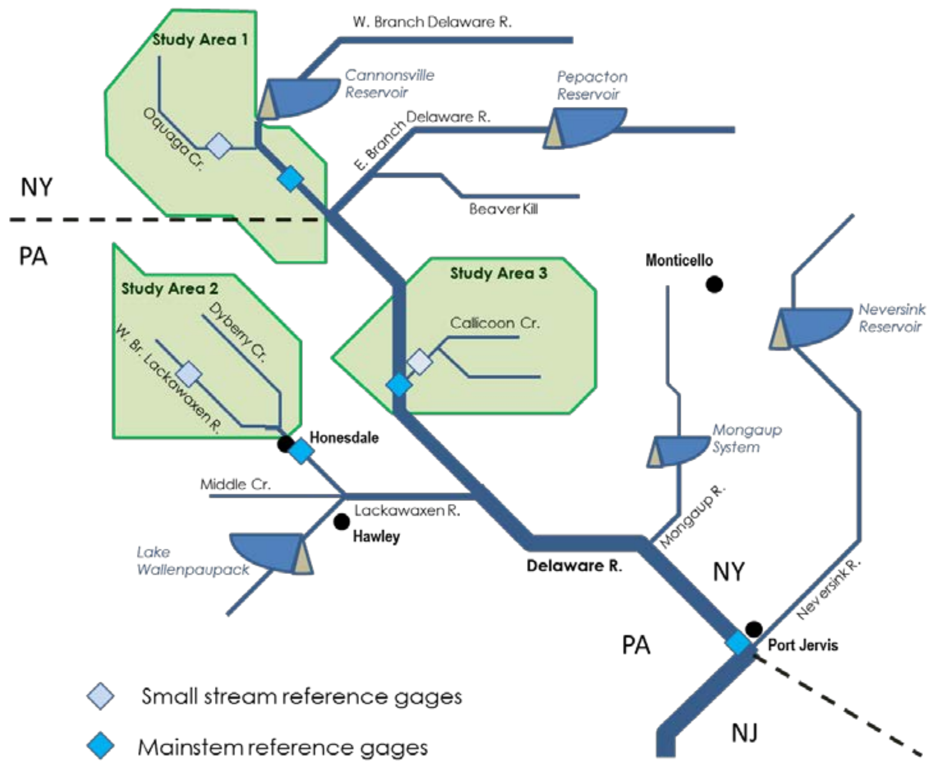
The withdrawals are highest in the maximum-year scenario, and it is these rates of withdrawal that may have the highest potential impact on flows in the DRB. The wastewater flow generated, as expected, is small relative to water use (but at 50,000–300,000 gallons per day in the study areas, it is still a large volume that must be managed).

Impacts from Water Withdrawal

The impact of water withdrawals for fracking depends on the rate of extraction and the available water resources in the study area. This withdrawal rate is roughly 2.6–3.0 million gallons per day (MGD) for each study area. To determine the impact of these extractions on water availability in the study areas, we compared the water-extraction rate to water availability using two types of reference stream gages: “small stream” and “mainstem.” We obtained all stream gage records from the USGS Surface Water Daily Data database [56-57] (see Appendix B for details on the gages used).

The schematic in Figure 11 shows the relative locations of the two types of reference gages. Conveniently, all projected wells are upstream of the stream gage at Port Jervis, NY, which is useful for assessing basin-wide impacts. The small stream gages represent smaller headwater drainage basins whose flow depends almost entirely on rainfall within the study area. The mainstem gages measure larger rivers flowing through the study area that have a significant portion of flow coming from upstream of the study area. Notably, the mainstem of the Delaware River flows through Study Areas 1 and 3, and water availability is influenced by upstream flows, including releases from the Cannonsville and Pepacton Reservoirs. Study Area 2 is different than 1 and 3 because it is entirely a headwater area and has no upstream drainage area to boost flow to the mainstem gage.

Figure 11. Flow schematic for the Upper DRB, showing locations of study areas and reference gages.



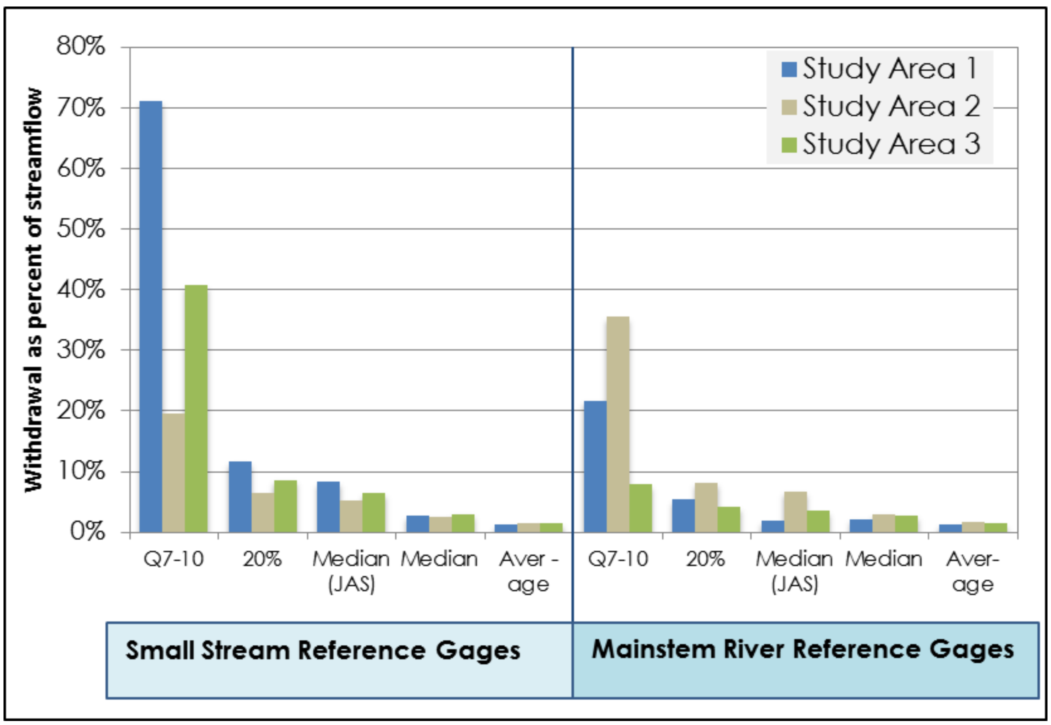
Note: The schematic is not to scale. Source: CNA.

For all gages, streamflow statistics were calculated including the Q7-10 (lowest seven-day average flow expected to occur once every 10 years), the 20th-percentile flow (sometimes called the Q80), median flow for the summer months (July–August–September [JAS]), median flow, and average flow per square mile (using the stream gages' contributing area). See Appendix B for these flow metric values. We divide the projected water withdrawal by the study area size to put demand on a per-square-mile basis, allowing a comparison.

We calculated water availability by dividing the maximum-year water demand for UNGD by the flow metric and expressing the result as a percentage. This is the percentage by which flow would be reduced under the listed flow conditions on days with water withdrawal (roughly half of days). Figure 12 shows the percentage of flow reduction for several flow metrics for both the small stream and mainstem reference gages.

The water availability analysis in the figure suggests that water withdrawals would reduce median or average flows by 1–3 percent, but the withdrawals may reduce flows 5–70 percent during summer and low-flow periods. Mainstem withdrawals would have a less-noticeable effect on flows under a range of flow conditions. By contrast, during periods of low-flow, withdrawal rates may noticeably reduce in-stream flow on small streams.

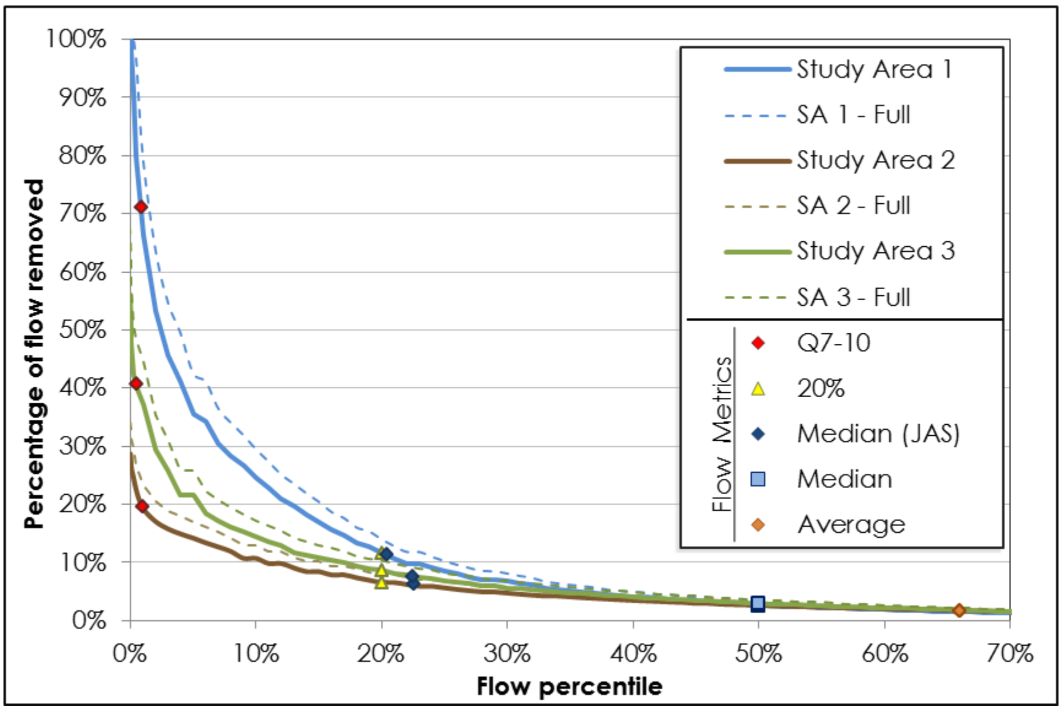
Figure 12. Withdrawals as percent of available streamflow for maximum-year development scenario. Shown for several flow metrics for both the small stream and mainstem gages. Withdrawals can take a high percentage of flow during low flow, when taken from small streams, and a lower percentage during average flow or when taken from mainstem rivers. (Units = percentage of flow removed.)



Notes: Q7-10 is lowest 7-day average flow experienced on average every ten years. 20% is the 20th percentile of daily streamflow. Median (JAS) is the 50th percentile daily flow for the months of July, August and September. Median is the 50th percentile of all daily flows. Average is the daily average flow.

For completeness, we also display the results over the full-flow distribution for the small stream gages. In Figure 13, lines show the percentage that flow would be reduced versus the flow percentile. The same flow metrics are shown as points along the line. The dashed lines represent an additional scenario if the full water demand were met with freshwater withdrawal (versus a combination of freshwater and reused water as depicted in Figure 10).

Figure 13. Withdrawal as percent of available flow versus flow percentile, small stream gages, maximum-year withdrawal scenario. At lower flows, the percentage of flow removed is higher. Dashed lines show the difference if all water needed for hydraulic fracturing were supplied by the streams.



Actual impacts would depend on the specific withdrawal location, withdrawal rates, and flow at the time of the withdrawal. Some ecosystems are highly sensitive to changes in flow regime, including changes to the low-flow magnitude, timing, and duration, which this study indicates may be a risk for smaller streams in the study areas. Several reviews of environmental flow literature have found that decreased magnitudes of low flows can lead to a range of effects on water quality and ecosystems, including decreased richness of species, increased densities of predators, increased abundance of generalist and highly mobile species, and decreased abundance of specialist and cold-water obligate species, among many others [58-59].

The total water volume needed to develop all 4,000 wells in the DRB is roughly 14 billion gallons, which, spread evenly over 30 years, is 1.3 million gallons per day. This average daily withdrawal amount would be sufficient to meet the domestic water needs[3] for more than 17,000 people. Of course, the water withdrawals for fracking would be roughly 80-percent consumptive, versus about 20-percent consumptive for domestic water use.

Relative to existing water demands in the study areas' watersheds [61], the UNGD water demands would increase water use in the three study areas by a factor of 5 to 12.

Wastewater Pollutant Loadings

Table 6 shows expected concentrations (derived from literature values) of some of the key regulated contaminants in the flowback and brine wastewater [41, 43, 62-68] and industrial wastewater effluent [40, 43], compared to the effluent discharge limits [69] and the reference conditions in the watershed's streams [41]. The natural gas wastewaters contain dozens of pollutants, including salts, metals, hydrocarbons, volatile organic compounds, and radioactive compounds, among others[70]. This study focuses on five pollutants whose effluent concentrations are regulated from treatment plants treating oil and gas wastewater in Pennsylvania. These pollutants include Total Dissolved Solids, Chloride, Sulfate, Barium, and Strontium.

[3] The average for Delaware, New Jersey, New York, and Pennsylvania is 75 gallons per day, per capita [60].

Table 6. Wastewater concentrations of key contaminants in flowback and brine wastewater. Discharge regulations on effluent concentrations, and reference conditions for surface water in the upper DRB are shown for context. Units = mg/L.

Pollutant	Flowback	Brine	Range	Discharge Regulations	DRB Reference
Total Diss. Solids (TDS)	73,000	205,600	38,500–261,000	500	46.5
Chloride (Cl)	54,600	99,600	19,600–174,700	250	5.8
Sulfate (SO_4)	51	55	2.4–300	250	5.1
Barium (Ba)	1,020	33,630	4–84,300	10	0.021
Strontium (Sr)	1,190	5,230	350–4,800	10	0.025

Since 2010, Pennsylvania regulations [69] require new wastewater treatment facilities treating Marcellus Shale wastewater to meet additional standards for TDS, salts, and some metals before discharging to streams or conventional treatment plants. The newer industrial treatment facilities will have to more-effectively remove salts, metals, and other contaminants through advanced treatment technologies (e.g., desalination and distillation; reverse osmosis and other membrane processes; capacitive deionization [39]) to meet the newer regulations. The reference conditions reflect an average for four sites in the Upper DRB measured in 2012 [41].

These pollutant measures show the concentrated nature of the wastewaters being generated relative to the regulatory effluent discharge standards, many of which are equivalent to U.S. Environmental Protection Agency (EPA) maximum contaminant levels for drinking water. The low concentrations in the reference conditions indicate how susceptible the surface waters in the study area are to even small discharges of wastewater. The potential environmental effects depend on the loadings of the contaminants to surface water in addition to the location and flow conditions at point of discharge. Different measures of loading may be appropriate, depending on the planning objective.

The total loading of contaminants in flowback and brine wastewater sets an upper bound for the mass of contaminants that must be treated. For the five regulated contaminants in Table 6, we calculate the total contaminant loading in wastewaters by multiplying flowback and brine generation flow rates by their respective contaminant concentrations to compute mass loads, and then sum the flowback and brine loads. The process is similar for industrial wastewater effluent (after typical wastewater reuse), but we assume that the effluent concentrations comply exactly with regulatory limits for discharge (see Table 6, above).

Table 7 shows the potential average daily loadings of key contaminants from all flowback and brine wastewater ("Avg. WW") and from treated effluent ("Avg. Effl."). The treated effluent volume is lower because it reflects the remaining wastewater volume after much of the original flowback and brine has been recycled. For context, the average daily loadings (computed based on the reference concentrations and average flow conditions) are shown on the final line for the Delaware River at Port Jervis, NY. The river naturally carries some solids and salts at low concentrations, but with high flow rates, the river loading is large.

The same is not true of the metals barium and strontium, which have only trace concentrations in the waters of the Upper DRB. In untreated wastewater (the Avg. WW scenario), the loadings of barium and strontium can dwarf those in the river, indicating significant risk associated with spills. Wastewater reuse reduces volume (the difference between Avg. WW and Avg. Effl. flow), and treatment reduces contaminant concentrations, which combined reduce average loadings in effluent discharged to rivers.

Table 7. Potential average daily loadings of key contaminants from all flowback and brine wastewater and from treated effluent. Natural gas wastewaters are very concentrated, and loadings of key contaminants in the raw wastewater ("Avg. WW") can be similar to the totals carried by the Delaware River ("*Reference*" condition). For the effluent loading scenario ("Avg. Effl."), which includes wastewater reuse, the loadings are greatly reduced, though not eliminated. Units = lbs/d, except flow (MGD).

Scenario[a]	Study Area	Flow	*TDS*	*Cl*	*SO_4*	*Ba*	*Sr*
Reference	*DRB[b]*	*3,260*	*573,400*	*71,700*	*62,300*	*264*	*305*
Avg. WW	1	0.040	32,000	23,100	19	2,490	700
	2	0.047	37,700	24,500	20	2,640	740
	3	0.042	33,600	21,800	18	2,350	660
	DRB[b]	0.245	142,400	127,400	105	13,800	3,870
Avg. Effl. (w. reuse)	1	0.006	25	13	13	0.50	0.50
	2	0.007	30	15	15	0.59	0.59
	3	0.006	26	13	13	0.53	0.53
	DRB[b]	0.037	154	77	77	3.1	3.1

[a] Multiply loadings by 6 for maximum-year, and by 30 (times 365) for total loading.

[b] Reference DRB loadings based on average flow at Port Jervis, NY. DRB scenario loadings include all wells in the DRB, including those not in the three study areas.

Note: TDS – Total dissolved solids, Cl – Chloride, SO4 – Sulfate, Ba – Barium, Sr - Strontium

Finally, we note that the high contaminant concentrations in untreated wastewater make wastewater handling a potentially risky activity in case of spills. Comparing the average wastewater loads to the reference loads, it is evident that spilling even small volumes of untreated wastewater into streams could significantly raise loadings of these contaminants (and many others in the untreated wastewater), posing an environmental risk. This study does not investigate spill scenarios, but the sensitivity of the basin's waters to spills may warrant further study.

Impacts of Wastewater Discharge

The salts, metals, and other pollutants in the flowback and brine wastewater can create significant loads, despite relatively low flow rates, because the pollutants are concentrated. The TDS concentration in brine makes it nearly six times saltier than seawater (roughly 35,000 mg/L). One way to judge the impacts of the effluent discharges in context is to determine how much the wastewater discharge would raise concentrations of key contaminants in surface waters.

Water quality risk is highest when a high effluent flow is discharged during low-flow conditions, because there is less water for dilution. We investigated two discharge flow scenarios to set a range on the potential water quality changes during a period of lower flow—in this case, the 20th-percentile flow (sometimes called the "Q80"). In both cases, we assumed that the discharge pollutant concentrations exactly met the quality standards in the "Discharge Regulations" column of Table 6 (see page 36).

The first scenario ("Max. Effl. w reuse") has the effluent disposal flow from the maximum development year (final column from Table 5, page 31) as its flow. This is the flow remaining after reuse. The second scenario ("Max. Effl. no reuse") has the total wastewater generated in the maximum development year (sixth column from Table 5) as its flow, but it meets the same effluent quality standards.

Given that potential effluent or discharge locations are unknown, we compute the concentration increase caused by diluting the wastewater pollutant loads in the reference streamflow on area-averaged basis. We use the small stream–gage statistics calculated per square mile to estimate the 20th-percentile flow and multiply by the area of the study area to get the flow rate. Table 8 shows the *increase* in concentration the wastewater effluent discharge would cause for the three study areas for the five pollutants. The first row of Table 8 shows the reference pollutant concentrations for natural flow from Table 6. Comparing the concentration increase to these reference concentrations shows the approximate magnitude of the change in water quality.

Table 8. Increase in concentration of pollutants caused by maximum-year effluent discharge during the 20 percent–flow condition. The “Max Effl. no reuse” scenario leads to larger increases than the “Max Effl. with reuse” scenario because of higher flow. Barium and Strontium concentrations change most relative to reference concentrations. Units = MGD for streamflow, effluent flow; mg/L for reference concentration, concentration increase

Scenario	Study Area	Streamflow	Effluent Flow	Concentration Increase				
				TDS	*Cl*	*SO_4*	*Ba*	*Sr*
Reference Concentrations for DRB:				*46.5*	*5.8*	*5.1*	*0.021*	*0.025*
Max Effl. w reuse	1	22.2	0.036	0.817	0.409	0.409	0.016	0.016
	2	40.2	0.043	0.530	0.265	0.265	0.011	0.011
	3	31.4	0.038	0.605	0.302	0.302	0.012	0.012
Max Effl. no reuse	1	22.2	0.240	5.412	2.706	2.706	0.108	0.108
	2	40.2	0.283	3.513	1.757	1.757	0.070	0.070
	3	31.4	0.251	4.004	2.002	2.002	0.080	0.080

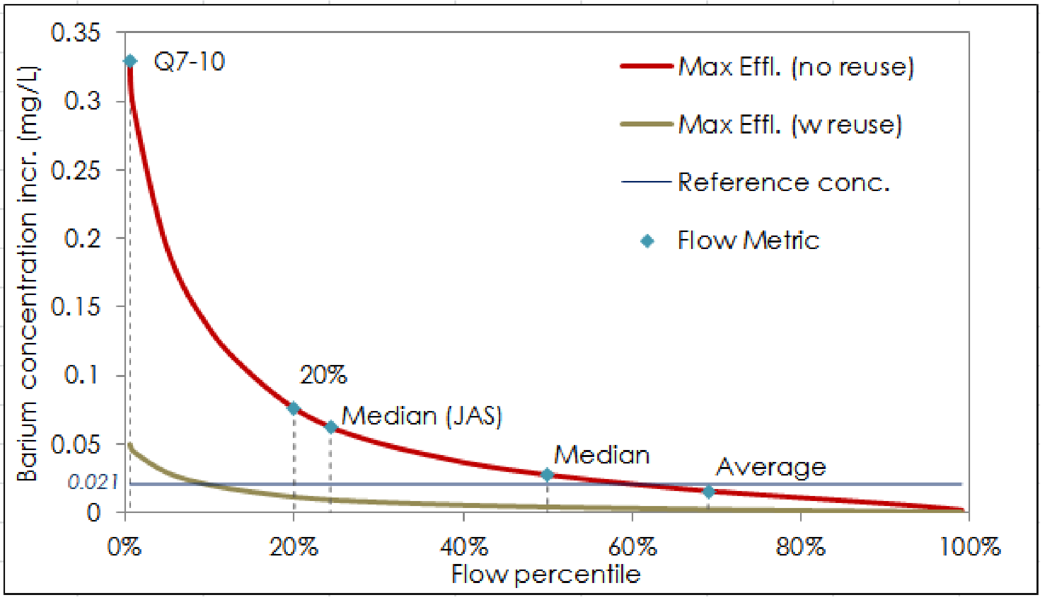
Note: TDS – Total dissolved solids, Cl – Chloride, SO_4 – Sulfate, Ba – Barium, Sr - Strontium

The Max. Effl. with reuse scenario’s increased concentrations reflect a wide variation in percentage changes, with TDS increasing about 1.5 percent over reference concentrations in the study areas, and barium and strontium increasing 50–70 percent. The increased barium loadings are especially of concern, because barium accounts for up to 90 percent of eco-toxicity potential in flowback and brine wastewaters [71]. The lower the wastewater reuse rate, the higher the potential effluent loadings. For barium and strontium, treating all of the wastewater (i.e. no reuse) instead results in a 300–500-percent increase over reference concentrations.

The water quality changes also depend on the flow conditions in the effluent’s receiving water due to the dilution effect. Figure 14 illustrates how the increase in barium concentration changes depending on the flow conditions at the time of discharge. This example considers the same scenarios for Study Area 2. The horizontal blue line shows the reference concentration for barium.

Unsurprisingly, we observe that the concentration increases are much higher during lower flows, and the larger discharge volumes of the no reuse scenario result in larger changes to concentrations. This general pattern will be reflected for all of the pollutants in all of the study areas, though the reference concentrations will be different.

Figure 14. Barium concentration increase versus flow percentile, Study Area 2. The concentration increases are most substantial for the lower flow percentiles. Scenario with no reuse has higher increases. Units = mg/L.



Discussion

If natural gas development were allowed in the DRB, water resources would be affected by both water withdrawals and wastewater discharges. Water withdrawals are small relative to total water availability in the basin, but are large compared to existing demands in the study areas. The withdrawals could remove a significant portion of flow if maximum year withdrawals are taken from smaller streams during critical low-flow periods. In this analysis, we compared the withdrawal rate and available flow generation on the basis of 'flow per unit area' over the area of the watershed for the three study areas. While this analysis method is necessary to compare relative flows where actual withdrawal location and timing are unknown, in reality, the impact would depend on the specific location and flow conditions during the withdrawal. On smaller streams, especially, the magnitude of water permanently removed for fracking could reduce the flow considerably during high or peak withdrawal periods. The duration of the impact is uncertain and would depend on how many wells would be served by a particular withdrawal location, and the rate of development.

Wastewater handling, management, and treatment are important for Marcellus wastewaters, notably the flowback and brine, due to the high concentrations and potential toxicity of pollutants in the wastewaters. We considered only the impact that the discharge of wastewater effluent treated to current Pennsylvania standards would have on in-stream concentrations of five pollutants with specific discharge limits. Our analysis showed that under these conditions, in-stream loadings of some pollutants (notably barium and strontium) could increase between 50 and 500 percent, depending on what portion of the wastewater is reused versus treated and discharged. These effects would be most pronounced on smaller streams and during low-flow periods, where the discharge flowrate is a reasonable proportion of the ambient flow.

There are several other potential risk pathways and risks to water quality [50, 72] that this study does not consider. Pollutants other than the five included here—as well as their degradants or derivatives—may pose additional risks to water quality and human and environmental health. The treatment processes needed to meet the 2010 discharge regulations on TDS, chloride, and sulfate may also treat other salts and ionic compounds, and limits on barium and strontium may result in reduced concentrations of other metals. Yet, for many of the pollutants found in natural gas wastewaters (many of which have no regulatory discharge limits), understanding of potential health impacts is still evolving (see the "Health Risks and Affected Population" chapter for more discussion of this issue). For instance, iodide and ammonium (two chemicals not usually measured in water quality analyses of flowback or brine) in Marcellus wastewater effluent have recently been shown to impact formation of disinfection byproducts in drinking water, as well as having ecologic effects [43-44, 73]. Naturally occurring radioactive materials (NORM) in flowback and brine have attracted attention because they are not easily treated and do not quickly degrade in the environment, whether in effluent or solid waste discharge [74-75]. Additional research on effluent concentrations of a wider range of chemicals from wastewater treatment plants meeting the newer Pennsylvania standards would be useful in assessing potential impacts of these other pollutants.

While effluent discharge was the primary water pollution pathway that we included in this analysis, there are other documented pollution pathways by which natural gas wastewaters could be released. For example, Reaven and Rozell performed a probability bounds analysis to determine the likelihood and potential volume of water contamination via transportation of wastewater, well casing failure, migration through subsurface fractures, wastewater spills at the drilling sites, and wastewater disposal [5]. They found that although wastewater disposal (i.e., effluent discharge) was by far the most likely pathway with the highest potential contamination volume, other pathways could lead to low-probability scenarios with high-contamination volumes, especially spills at drilling sites. These "accident" pathways [50] are important considerations in a full consideration of UNGD risk, as some spills will be nearly inevitable [74]. Pennsylvania's Department of Environmental Protection has been tracking and reporting permit violations for natural gas operators, and their violations data show that many of these pathways are a reality in Pennsylvania, with 4,006 violations since 2009 (roughly 7,800 wells drilled) [76]. As an example, there have been roughly 290 violations at about 240 well sites involving improper discharge of UNGD wastewaters to Pennsylvania's streams [76].

The next chapter of this report investigates a different category of water quality risks: those associated with the changes to land cover we described in the "Impacts on Land Cover" chapter.

Impacts on Water Quality due to Changes in Land Cover

Key Findings

- Changes in land cover associated with natural gas infrastructure would lead to short- and long-term changes in hydrology and water quality.
- Changes in land cover could increase erosion rates up to 150 percent immediately after infrastructure construction and 15 percent in the long term.
- Soil-erosion rates during winter months are up to 25 times higher than during summer months.
- Runoff rates could increase by up to 4 percent, offset by an equivalent volumetric decline in groundwater contribution to streamflow.

Unconventional natural gas development results in landscape disturbance based on the need to construct infrastructure to support operations. This report's chapter titled "Impacts on Land Cover" described the potential changes to land cover associated with constructing well pads, roads, and gas gathering pipelines. These changes to the landscape also change the hydrologic character of the DRB, and can affect water quality through changes to sediment and nutrient export. Building roads, pipelines, and well pads requires clearing the land, removing topsoil, regrading, and compacting soil both in the infrastructure footprint and a right-of-way wide enough to install infrastructure. Mitigation measures—such as erosion- and sediment-control practices (silt fences, filter socks, and so forth) and remediation with planting of cover crops—can limit the loss of soil, but some permanent impact due to the initial land clearing and soil compaction is inevitable.

The full scope of water-quality outcomes resulting from land cover changes depends on the location of the infrastructure, the existing watershed conditions, and the mitigation measures put in place by developers. Infrastructure that is built on land with high slopes and erodible soils; near or adjacent to stream banks; or necessitating the crossing of a stream or disturbance of wetlands will have a larger potential for ecological damage, primarily through erosion. The current condition of the basin in the three study areas is predominantly forested and agricultural, with limited residential and commercial development.

The previous chapter covered some of the potential impacts of the natural gas wastewaters on water quality. This chapter, by contrast, focuses on potential impacts on water quality due to the largely unavoidable land cover changes associated with UNGD. Such land-use changes often correlate to changes in hydrology, water quality, and—by extension—stream health. At the site scale, well pad development has been observed to increase sediment and nutrient concentrations, though vegetated stream buffers and erosion- and sediment-control practices can reduce loadings [77]. At a regional scale, development of well pads has been shown to correlate with increased in-stream Total Suspended Sediment loads [4], due to erosion and sedimentation.

Methodology

We modeled each of the study areas with the MapShed program developed by Penn State University [78]. The water quality calculations were performed with MapShed's integrated GWLF-E model based on the Generalized Watershed Loading Function [79], which simulates runoff, sediment, and nutrient loads based on watershed source areas. We modeled each of the study areas under three conditions:

- **Baseline:** Existing land cover
- **Initial Infrastructure:** Well pad, gathering pipeline, and new roads during or immediately after installation with minimum mitigation
- **Post-Development:** Infrastructure after the hydraulic fracturing operations are complete and gas is being produced, with partial remediation

The Initial Infrastructure condition represents a worst case of erodibility conditions that would likely persist from several days to a few months as the well pads, roads, and pipelines are constructed. This scenario is useful for setting the upper limit on the potential sediment and nutrient loadings, and determining which months of the year have conditions most conducive to erosion in the study areas. This scenario also assumes that the entire land conversion for infrastructure in a study area occurs at once, when, in reality, it would be installed at the pace of development over 30 years.

The Post-Development condition considers the long-term effects of land-use change after all the gas wells have been drilled and are in production. The well pads are partially deconstructed (leaving only a well head, pump, and brine storage), and the gathering pipeline rights-of-way are revegetated with cover vegetation (low grasses and herbaceous plants); pipelines are operating, and the roads are little changed. We assumed (through parameter selection, not direct modeling) that some erosion and sediment control best management practices (BMPs) are installed, though not optimally, and that the post-development soil would remain somewhat compacted. Ultimately, the Initial Infrastructure and Post-Development scenarios should bracket a range of conditions reflecting a range of potential remediation cases.

We also assumed that all land cover changes are permanent, that there are no other land cover changes in the study area, and that there are no secondary land cover changes (e.g., converting additional forest to farmland to make up for arable area lost to gas infrastructure). We also did not include long-distance transmission pipelines to move natural gas to market and other appurtenant natural gas infrastructure (e.g., centralized storage or wastewater treatment facilities) in this analysis.

The results presented consider only runoff and streamflow produced within the study area (no upstream flow for Study Areas 1 and 3), and only loadings associated with land-use and in-stream processes (no point sources, livestock, or septic systems are included in the model). The results focus on the hydrologic and loading changes on the uplands—that is, the changes in flow or pollutant loadings coming directly from changes in the land surface.

The metrics we used to assess the changes include the following MapShed model outputs:

- **Runoff:** The volume of water that flows off the land surface and into streams during storms
- **Groundwater Recharge:** The volume of water that soaks into the ground during rain events and contributes to streamflow
- **Erosion:** The mass of soil that is dislodged from the land surface by precipitation runoff and is carried into streams
- **Sediment:** The mass of soil that is deposited on land (generally as dust) that gets washed off into streams
- **Nutrients:** The mass of nitrogen (Total Nitrogen, or "TN") and phosphorus (Total Phosphorus, or "TP") compounds washed off the land surface in runoff or in groundwater entering the stream[4]

[4] These can contribute to algal growth, which can lower available oxygen in the stream.

Results

The land-use changes associated with UNGD in the DRB affect hydrology, loadings of sediments, and (to a lesser extent) nutrients in the study areas. The results vary significantly by scenario and condition (Initial Infrastructure versus remediated condition). Table 9 indicates changes in hydrology (runoff and groundwater recharge) and upland loadings (erosion, sediment, nutrients) for each scenario, expressed as a percent change from the baseline total. Only the land surface processes are included in the total.

Table 9. Changes in hydrology and loadings for each scenario. The land cover changes result in large increases in erosion and sediment ("Sed.") loadings compared to the baseline, especially for Dispersed scenario/Initial Infrastructure ("Initial Infra.") conditions. The hydrology and nutrient loading changes are smaller in magnitude. Units = % change from baseline.

Study Area	Development Scenario	Condition	Runoff	GW	Erosion	Sed.	TN	TP
1	Dispersed	Initial Infra.	2.8	-0.17	98	54	6.3	11
	Dispersed	Post-Dev.	1.6	-0.09	15	-2.1	-1.6	-5.0
	Concentrated	Initial Infra.	1.7	-0.10	67	33	3.7	6.9
	Concentrated	Post-Dev.	1.0	-0.09	10	-5.5	-1.8	-4.8
2	Dispersed	Initial Infra.	3.4	-0.64	138	125	32.0	49
	Dispersed	Post-Dev.	1.8	-0.32	16	14	2.6	2.7
	Concentrated	Initial Infra.	2.1	-0.43	102	93	23.0	35
	Concentrated	Post-Dev.	1.1	-0.27	13	11	1.8	2.1
3	Dispersed	Initial Infra.	3.4	-0.46	110	96	12.3	20.0
	Dispersed	Post-Dev.	1.9	-0.18	14	12	0.7	-1.6
	Concentrated	Initial Infra.	1.9	-0.18	66	57	7.2	12
	Concentrated	Post-Dev.	1.0	-0.14	8.0	6.8	0.3	-1.1

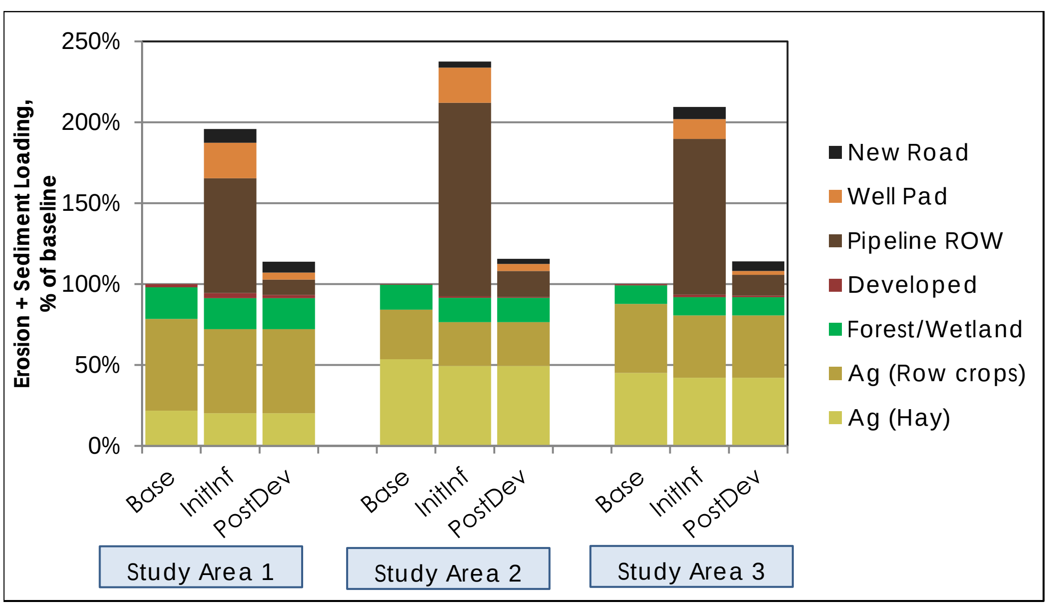
Notes: GW = Groundwater recharge

The hydrologic changes show increases in runoff of 1–3 percent, with reductions in groundwater recharge of a few tenths of a percent. On a volume basis, however, these changes are nearly equal, so average yearly streamflow is nearly unchanged, but flow distribution changes. The flows increase (roughly 1.5 percent) at peak flows, and decrease (1 percent or less) across the rest of the flow distribution. In volume terms, the groundwater contribution to flow will decrease by somewhere between 70 (Concentrated scenario, Post-Development conditions) and 145 million gallons per year (Dispersed Scenario, Initial Infrastructure conditions) for Study Area 1. The corresponding ranges are 140–330 million gallons for Study Area 2, and 90–305 million gallons for Study Areas 3. On an area-averaged basis, the approximate range of decreased groundwater flow is 0.35–2 million gallons per year, per square mile.

Table 9 also shows a noticeable change in the erosion and sediment loadings, and less significant changes in nutrient loading. Erosion and sediment changes both increase suspended sediment loadings in streams, but the sediment loadings are much smaller in magnitude. Combining these loadings gives a clearer picture of the potential changes in soil volume leaving the landscape.

Figure 15 illustrates how the combined erosion and sediment loadings change, and how the individual land-use changes affect them. Results are shown as a percentage of the baseline total load (upland only). Thus, the baseline load equals 100, and 240 would represent a 140-percent increase. The stacked bars show the relative contribution of each existing land cover (forest/wetland, agricultural hay and pasture, agricultural row crops, and developed area) and gas infrastructure land cover (well pads, pipelines, roads) to the total loading. The largest contribution to the erosion and sedimentation impacts are from the pipeline right-of-ways, especially for the Initial Infrastructure ("InitInf") condition. The impacts from roadways are smaller in magnitude but are not reduced as much in the Post-Development ("PostDev") condition, as compared to well pads and pipeline rights-of-way.

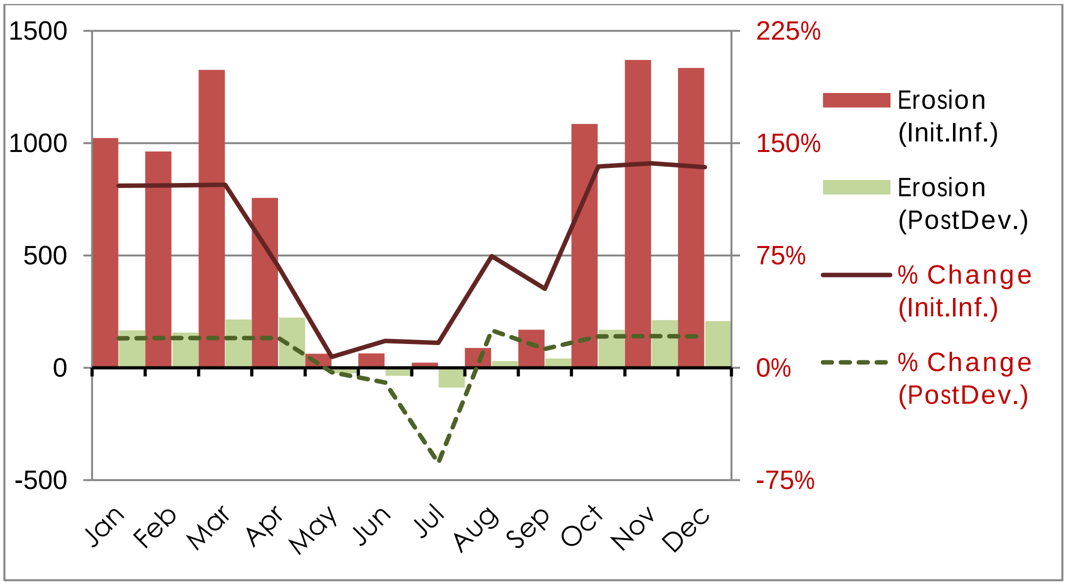
Figure 15. Total upland erosion plus sediment loading, as percent of the baseline loading. Increases in erosion and sedimentation are caused mainly by the pipeline rights-of-way and are more severe in the Initial Infrastructure ("InitInf") condition than the Post-Development ("PostDev") condition. Units = percent of baseline. (baseline = 100)



The total change in loading also depends on the types of land cover affected by the conversion. The relative amount of agricultural versus forest area converted has a strong influence on the upland loading results. For example, converting forest area to natural gas infrastructure increases loads, while agricultural (and especially cropland) conversions may lead to net reductions in some loads, especially nutrients. This accounts for much of the variation in the nutrient results in Table 9 (page 46).

We also found the potential changes to erosion rates vary widely during the year. Figure 16 shows the monthly variation in erosion relative to the baseline condition for both the Initial Infrastructure and remediated condition. The changes in winter erosion predominate and account for most of the total change. The difference is such that if the Initial Infrastructure conditions persisted for three months, 25 times more erosion would occur if all infrastructure were built in October through December versus May through July.

Figure 16. Monthly variation in erosion relative to the baseline condition for both the Initial Infrastructure and Post-Development condition. Most of the increase in erosion between baseline and developed conditions occurs in winter months. Units = tons (left axis); percent change (right axis).



Discussion

The land-use changes associated with UNGD in the DRB have the potential to cause noticeable changes in hydrology and erosion, despite affecting a relatively small proportion of the basin. The Initial Infrastructure conditions result in the highest susceptibility of the study area to erosion, noticeably in the winter months. Even in the Post-Development condition, the additional roads, pipelines, and well pads do not perform the same hydrologic functions as the forests they replace, resulting in potentially long-term increases in peak runoff, erosion, and nutrient loading, and possible decreases in stream base flow.

By way of context, in Study Area 2 (178 square miles), the volume of runoff-increase and groundwater recharge–decrease both equal roughly 330 million gallons per year (0.9 million gallons per day) for the "dispersed" scenario for the Initial Infrastructure condition. This yearly volume of water would fill the Empire State Building 1.2 times. Also, if the Initial Infrastructure conditions persisted for three months, on average, approximately 18,000 tons of soil would be eroded. If piled on top of an average suburban house lot (one-quarter acre), the pile of soil would be 45 feet tall.

The results report only the net changes averaged across the entire case study watersheds. The most prominent changes are likely to occur in the upland portions of the watersheds and in small streams and ponds adjacent to the infrastructure development. Further modeling would be needed to assess potential impacts on a smaller scale. Additional land development (for housing, more agriculture, other uses) in the watershed may be more likely to cause downstream impacts, as the hydrologic and water quality functions of upland streams would start as more degraded.

This analysis is a limited one and does not account for the full range of impacts that may result from land-use changes associated with gas development. This analysis used the Mapshed model to estimate pollutant changes over the study area using typical factors for the types of land covers described. It does not cover the large potential variation in parameters such as curve number, soil bulk density (compaction), or other soil factors. Furthermore, the model parameters cannot directly account for the impact of best management practices, or the impacts that may occur were these practices to fail. Pennsylvania data on permit violations indicate that erosion- and sediment-control violations at well sites are relatively common (roughly 630 violations at 530 well sites since 2009) [76]. The severity of these violations is not known, but in some of these cases, the failure (or absence) of best management practices for erosion and sedimentation could result in loadings closer to the Initial Infrastructure condition than the Post-Development condition presented here.

In addition, the flow changes and changes to sediment loadings are likely to affect the ecological conditions of the watershed. The land cover changes will likely result in environmental flow changes (especially increased peak flows and decreased base and low flows), which can affect the health and relative distribution of a wide range of plant and animal species [58-59].

We recommend further study to better assess water-quality outcomes using more-detailed models with greater spatial resolution and more-detailed parameters using sampling data from the modeled watershed. For instance, variability in agricultural practices can have a strong influence on erosion rates and nutrient export. Further study could also compare alternate future land-use changes (e.g., more suburban development) with results for land-use change specifically associated with gas development. Additional study with a more-detailed case study model could also investigate the combined effects of water withdrawal, wastewater effluent disposal, and land cover changes.

Impacts on Air Quality

Key Findings

- Natural gas development could as much as double nitrogen oxides (NO_x) emissions, compared to current emissions in affected DRB counties.
- The primary source of NO_x emissions from natural gas development could stem from compressor stations to move the gas through gathering pipelines, rather than from well development or completion.
- Compressor stations represent a long-term source of NO_x emissions in impacted areas, rather than the short-term, intermittent impact from well development.
- Methane leakage from natural gas development in the DRB could contribute an additional 0.5–2.2 percent per year to the current methane emissions from Marcellus Shale development now occurring in Pennsylvania and West Virginia.

Unconventional natural gas development is an industrial process that involves a host of machinery and operations to extract natural gas from shale deposits. Shale gas operations release a variety of pollutants that can degrade local air quality, including nitrogen oxides (NO_x); sulfur oxides (SO_x); particulate matter (PM); and volatile organic compounds (VOCs), such as formaldehyde, benzene, toluene, ethylbenzene, and xylene (BTEX) [80]. NO_x, SO_x, and PM are subject to national ambient air-quality standards, (NAAQS) due to their potential to cause harm to human health and the environment [81]. Furthermore, NO_x and VOCs are the precursors to ozone, the primary component in smog, which can cause respiratory illness [82].

Impacts on air quality from industrial emissions occur during each of the stages of shale gas development [82]. These emissions stem from the use of diesel-powered equipment to prepare well pads and diesel trucks to transport water and supplies to and from well pads. The drilling, hydraulic fracturing, and production processes also utilize diesel machinery and contribute to these emissions. In addition, condensate tanks and waste ponds at well pad sites can produce emissions. Significant emissions can also arise from combustion-powered compressor stations that compress natural gas to keep it flowing through the pipeline system.

While these local risks to air quality would most likely impact the DRB in the short term, there is a large field of research that has focused on the potential climate change impacts due to greenhouse gas (GHG) emissions from shale gas development [80, 82-84]. These GHG emissions stem from the leakage of natural gas (i.e., methane, or CH_4) at various points throughout the development cycle, from extraction to processing and transmission. However, the combustion of natural gas to generate electricity releases half as much carbon dioxide (CO_2) as coal, leading many to champion the climate benefits of natural gas and term it a "bridge" fuel to the future. There is considerable debate as to whether the methane leakage from natural gas operations eclipses any of these gains from reduced CO_2 emissions, especially considering that methane has 34 times the greenhouse-warming potential (GWP) of CO_2 (on the 100-year time horizon); on the 20-year time horizon, methane has 86 times the GWP of CO_2) [85]. A recent study suggests that methane leakage should be below 3.2 percent to realize net climate benefits from the transition [86], while field measurements of methane losses have found a range from between 0.3 percent and 17 percent (see Table 11 below for references).

In this chapter, we focus on the potential emissions and impacts to air quality in the DRB from natural gas development. In particular, we calculated the potential contributions to VOC, NO_x, PM, and SO_x emissions from projected natural gas development in four DRB counties: Wayne County (PA), Broome County (NY), Delaware County (NY), and Sullivan County (NY). We performed this analysis at the county-wide scale to compare the results to EPA emission inventories. In addition to criteria pollutants, we calculated the potential contribution to methane emissions from projected natural gas development in these counties. We did not analyze the potential for any more localized impacts on air quality, as this was beyond the scope of the study.

Methodology

To assess the impacts to air quality, we applied relevant values from the professional literature to our build-out scenarios to calculate the emissions associated with natural gas development. For ease of comparison with the common emission values, we report the calculated emissions at the county level, rather than by study area. Furthermore, we used the two development rate scenarios described in Table 1 ("dispersed" and "concentrated") to illustrate the impacts of the development rate on air quality:

- **Average Development Year:** Assumes that development occurs at a constant rate over a 30-year build-out

- **Maximum Development Year:** Assumes that 20 percent of total well build-out in each county occurs in one year (up to a maximum of 200 wells/year, which is representative of the highest-developing counties in the Marcellus Shale today).

The average and maximum-year scenarios show the potential variation in emissions that could be expected from natural gas development activities in each county.

To assess the local impacts on air quality that might be expected from shale gas development in the DRB, we applied the emissions estimates from a recent study on Marcellus Shale development in Pennsylvania [87] to our projected well development results. This study provided emissions values for VOCs, NO_x, PM, and SO_x on a per-well basis during various well site activities, based on data reported from Marcellus Shale gas producers. In addition to well development, the study reported the contribution from compressor stations that support production. The study estimated emissions from compressor stations based on the reported "potential to emit" values from permits, which indicate the maximum amount of emissions the facility is permitted to emit by the Pennsylvania Department of Environmental Protection. We estimated the number of compressor stations in each county by assuming that a centralized station would serve all well pads within a 50-square-mile radius, based on estimates from Marcellus Shale operators in the New York Department of Environmental Conservation's Draft Supplemental Generic Environmental Impact Statement [88]. The study reported the high and low values of the range for each pollutant from multiple sites, and we used the average of these values to report results. To estimate the impact of the emissions, we compared the calculated emissions to the counties' reported emissions from the EPA 2011 National Emissions Inventory (NEI) [89].

To assess the greenhouse gas contributions that might result from shale gas development in the DRB, we calculated methane leakage as a percentage of the natural gas production expected in the DRB. To determine the natural gas production, we assumed that all wells would exhibit an average EUR of 1.6 Bcf per well (the same EUR value that we used to develop our build-out scenarios, see page 9), and applied a well decline curve based on a similar EUR [90] to estimate the monthly production per well in the DRB. We applied this value to the average number of wells that would be developed per month in the two annual scenarios to determine annual production. Using these production values, we then applied leakage rates based on relevant values from professional literature describing field measurements (top-down) of methane leakage (see page 58). We chose to focus on top-down studies for this assessment, based on a recent review of methane leakage from natural gas systems that found that assessments based on inventories (bottom-up) tend to underestimate this leakage [91].

For both the methane and non-methane assessments, our well-development results from the "concentrated" and "dispersed" scenarios result in similar number of wells developed. Thus, only the "dispersed" scenario is considered throughout this chapter.

Results

Criteria Pollutant Emissions

Table 10 shows the estimated annual pollutant emissions from shale gas development in the DRB, based on average and maximum annual well development scenarios. In addition to the number of new wells, we project that 22 new compressor stations could be built in the DRB to support transmission of natural gas through new gathering pipelines. We present the range of potential emissions expected from the two scenarios by evaluating emissions with one compressor station in each county, followed by the emissions with all 22 compressor stations present in the DRB. In each scenario, NO_x emissions would be the largest contributor to air pollution in the DRB from this development.

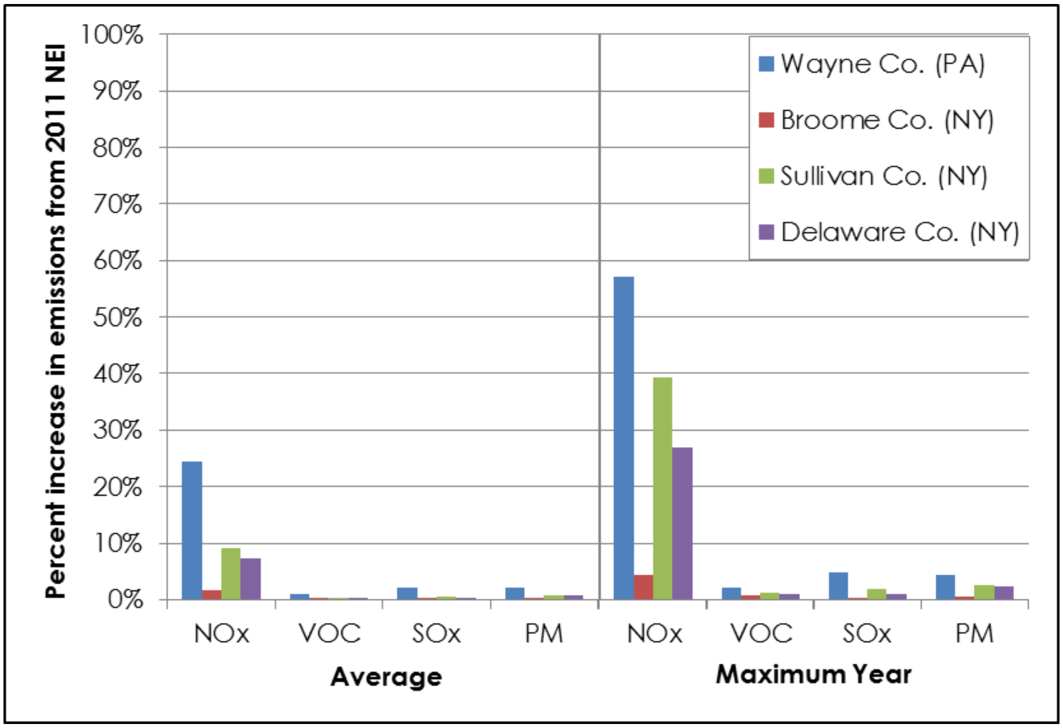
Table 10. Annual emissions estimates for projected natural gas development by county (and for one compressor station) in the DRB. NO_x emissions would be the largest contributor to air pollution by weight. Units = metric tons, unless noted otherwise.

County	Scenario	Wells	CH_4 (Bcf[a])	NO_x	VOC	PM	SO_x
Wayne	Avg	78	832	441	91	14	5.6
Broome	Avg	8	93	105	34	4.5	1.3
Sullivan	Avg	27	256	197	50	7.2	2.5
Delaware	Avg	16	184	146	41	5.7	1.8
DRB	Avg	129	1,365	889	216	32	11
Wayne	Max	200	2,081	1,026	190	31	13
Broome	Max	46	483	290	66	10	3.7
Sullivan	Max	163	1,698	850	160	26	11
Delaware	Max	98	1,024	539	108	17	6.8
DRB	Max	507	5,287	2,705	522	84	34

[a] Bcf = billion cubic feet.

To determine the extent of these emissions impacts, we compared the projected annual emissions from development in each county (plus one compressor station) to the total emissions of each pollutant in each county from the EPA's 2011 NEI. Figure 17 shows the results of this comparison for the two scenarios of annual well development.

Figure 17. Pollutant emissions from well development (and one compressor station) for average-year (left) and maximum-year (right) scenarios, relative to total county emissions from the 2011 NEI. Natural gas development could lead to a significant increase in NO_x emissions for three of the four DRB counties.



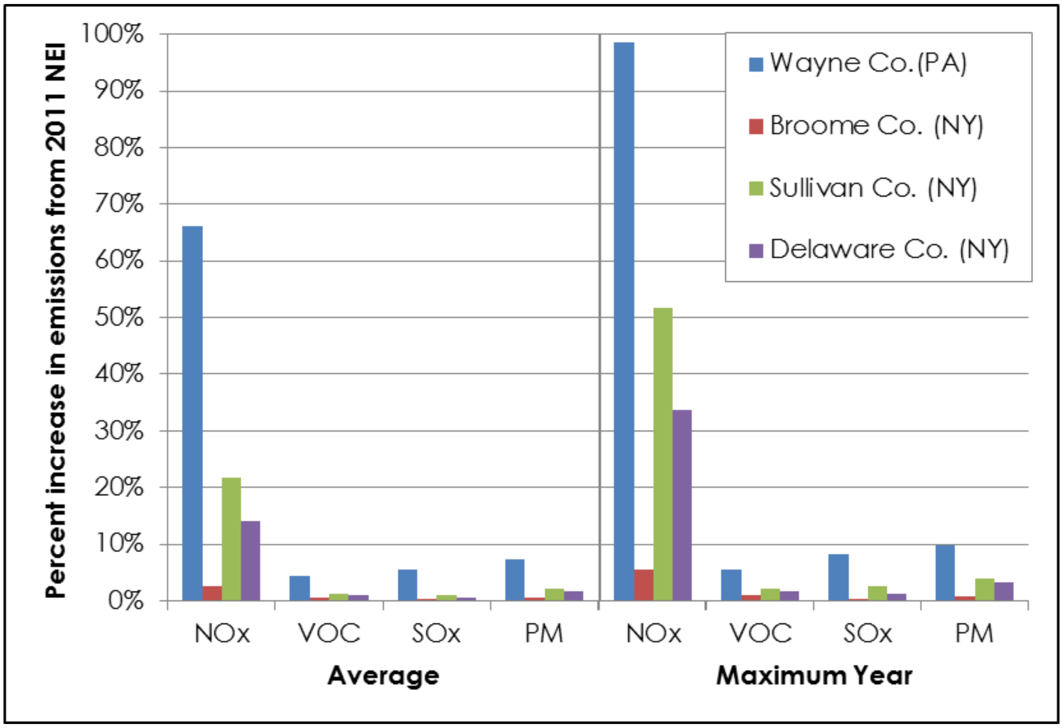
We see noticeable potential increases in NO_x emissions for three of the four counties: Wayne County (PA) and Sullivan and Delaware Counties (NY) could all see greater than a 27-percent increase in NO_x emissions under the maximum annual-development scenario. Under the average annual-development scenario, Wayne County could still see a substantial increase in NO_x emissions (25 percent) from the shale industry, but NO_x contributions from the other counties were all below 9 percent. Broome County (NY) did not see a significant increase in NO_x emissions in either scenario. This is not surprising, since only a small portion of Broome County falls within the DRB.

The contributions to VOC, SO_x, and PM emissions from annual shale gas development did not appear as significant compared to other activities in these counties. None of the counties showed a noteworthy increase in either the average year (less than 2 percent) or maximum year (less than 5 percent) scenarios at the county scale, though the individual pollutants, especially VOCs, could have impacts at a local scale (see "Health Risk Factors and Affected Population" chapter) .

While the emissions attributed to well pad development and well completion represent one-time contributions in the year the well was drilled, compressor stations will continually contribute to a county's emissions inventory after they are built. With this fact in mind, we determined the annual emissions from well development with all 22 compressor stations in place to see the impact on the DRB. Based on our projections, the 22 compressor stations would be spread out in the DRB counties according to the following breakdown: 12 in Wayne Co. (PA), 5 in Sullivan Co. (NY), 3 in Delaware Co. (NY), and 2 in Broome Co. (NY). This breakdown corresponds to the expected number of wells projected in each county. Figure 18 shows the updated annual emissions inventory for the two scenarios with the higher count of compressor stations. Note that these projections for new compressor stations only account for supporting gathering pipelines, and do not account for any additional compressors that may be needed to support larger transmission pipelines to carry the natural gas to market.

With the addition of a full complement of compressor stations, we see significant potential increases in NO_x emissions for three of the four counties. Wayne County (PA) and Sullivan and Delaware Counties (NY) could all now see greater than a 34-percent increase in NO_x emissions under the maximum annual-development scenario. In fact, NO_x emissions could almost double in Wayne County under that scenario, due to the addition of 12 compressor stations. Under the average annual-development scenario, Wayne County would still see a substantial increase in NO_x emissions (66 percent) from the shale industry, but NO_x contributions from the other counties were all below 21 percent. Broome County (NY) still did not see a significant increase in NO_x emissions in either scenario.

Figure 18. Pollutant emissions from well development (and 22 compressor stations) for average-year (left) and maximum-year (right) scenarios, relative to total county emissions from 2011 NEI. The full complement of compressor stations leads to a large increase in NO_x emissions in 3 of the 4 DRB counties.



The contributions to VOC, SO_x, and PM emissions from annual shale gas development did not appear as significant compared to other activities in these counties. Only Wayne County (PA) showed any relative emissions higher than 5 percent across these pollutants at the county scale.

Methane Emissions

Natural gas and petroleum systems represent the largest contributing sector to methane emissions in the United States [16]. Table 10 shows the projected methane emissions from natural gas development in the DRB. Using the well decline curve for a 1.6 Bcf EUR-model well, we estimated the annual production from natural gas development in the DRB to be 22.6 Bcf in an average year, and 87.5 Bcf in a maximum year. We applied methane leakage rates from the academic/professional literature to these production values to estimate the potential methane emissions from development in the DRB. Table 11 presents these results.

Table 11. Potential methane emissions from projected development in the DRB, based on methane leakage rates reported from field measurement (top-down) studies. Units = Bcf – billion cubic feet.

		Potential Methane Emissions (Bcf)	
Study	Leakage Rate	Average Year	Maximum Year
Peischl (2015) [92]	0.3%	0.1	0.3
Peischl (2015) [92]	1.6%	0.4	1.4
Peischl (2015) [92]	1.9%	0.4	1.7
O'Sullivan (2012) [93]	3.6%	0.8	3.2
Miller (2013) [94]	3.7%	0.8	3.2
Petron (2012) [95]	4.0%	0.9	3.5
Karion (2013) [96]	8.9%	2.0	7.8
Schneising (2014) [97]	9.1%	2.1	8.0
Caulton (2014) [98]	10.0%	2.3	8.8
Peischl (2013) [99]	17.3%	3.9	15.1
Average	6.0%	1.4	5.3

Applying the average leakage rate from the literature of 6 percent, we estimated annual methane emissions of 1.4 Bcf in an average year and 5.3 Bcf in a maximum development year. Applying the same methodology to current annual Marcellus Shale production, which is about 4 trillion cubic feet, we estimate total Marcellus emissions to be 240 Bcf. Thus, shale gas development in the DRB could contribute an additional 0.5 percent to 2.2 percent per year to the current methane emissions of the Marcellus Shale.

Discussion

If natural gas development were to proceed in the DRB, there could be varying impacts to air quality. Compared to activities that are already occurring in the DRB counties, our results suggest that NO_x emissions would be the biggest contributor to air pollution from shale gas development. By comparison, the projected NO_x emissions in Wayne County, PA, from the average year of natural gas development (with one compressor) would be equivalent to adding over 53,000 cars to the road in the county that year.[5]

[5] This is based on EPA's average NO_x emissions (0.693 g/mile driven) per year (12,000 miles driven) for passenger cars [100].

These counties currently enjoy clean, high-quality air, due to the absence of any major emissions sources such as power plants. However, localized development in certain parts of each county could still pose a reduction in air quality due to this development. Some studies have attributed this localized development to a variety of airborne health risk factors (see the “Health Risks and Population” chapter for more details and references). The primary contribution to these NO_x emissions could come from compressor stations, which represent a long-term source of emissions, versus the one-time contribution from well-development activities.

Furthermore, methane releases from natural gas operations are a significant contributor to methane emissions in the United States. Each year, if all 1.4 Bcf of potential methane leakage could be captured and used to fuel a natural gas power plant, roughly 139 gigawatt hours of electricity could be produced[6], enough to power over 16,000 homes in the area[7] for a year. While atmospheric methane does not necessarily have significant local effects, it is a powerful greenhouse gas that could have impacts beyond the DRB.

[6] The EIA estimates that 1,000 cubic feet of natural gas can generate 99 kilowatt-hours of electricity [101].

[7] Average monthly household electricity use in the Middle Atlantic region is 701 kWh [102].

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Health Risks and Affected Population

Key Findings

- More research and better tracking of health impacts are needed to reliably project how shale gas development could affect health *outcomes*. Scientific literature has shown that some health risk factors are related to distance (e.g., 1 km, 1 mile) from a well pad.
- Roughly 45,000 people live within one mile of a projected well pad location. This population predominantly resides in Wayne County, PA, where nearly 60 percent of the county's population could be affected by increased well development.
- Development of more wells per pad reduces the number of people in close proximity (<0.5 mile) to well pads, but potential exposures to certain risk factors could be prolonged.

Of the environmental impacts of unconventional natural gas development, those that pose a potential risk to human health often attract the most attention and concern. In large part, the link between unconventional Marcellus Shale gas development and adverse health outcomes has not been rigorously tracked in a manner that has produced conclusive scientific literature [103]. There has been considerable research into the potential pathways and risks of exposure, but the potential health outcomes depend on type, magnitude, duration, and frequency of exposure to contaminants and risk factors [104]. Just as previous chapters noted that there is variation in productivity of individual wells, water use, concentrations of wastewater contaminants, and air emissions rates, the potential risks to human health may vary considerably across the study area, and even from well pad to well pad.

While it is not possible to use the scientific literature to derive rigorous estimates of specific health metrics (e.g., cancer cases above baseline), a number of studies (see Table 12) provide some evidence that risk factors and possibly health outcomes correlate with distance from primary gas development activities (i.e., well pads). This analysis quantifies the population within certain distances from well pads as an initial estimate of the potential affected population.

While the link between natural gas development and health outcomes has not been rigorously investigated [103], the major potential exposure pathways have been explored. Krupnick et al. [50] documented the risk pathways (routine and accidental) of UNGD agreed upon by a wide range of experts. Of the 15 consensus risk pathways (those with priority for further regulation or voluntary action), 14 involved routine or accidental releases (of frac fluid, wastewater, methane, etc.) to air, surface water, or groundwater, indicating the potential for human health exposures. Where possible, this study considers the risk pathways and accompanying research indicating that risks or health outcomes vary with distance from the activity associated with the risk pathway.

Table 12 summarizes some of the risks and health outcomes identified in the literature based on distance from natural gas activities (most often associated with the well pad). Typically, these studies evaluate risk factors or metrics of health risks/outcomes at several distances from primary gas development activities, such as the injection well site. The most common distance-threshold for measuring the most likely risks is 1,000 meters or a half-mile. To evaluate more general risks, or establish a threshold distance for a control population, the selected distances are commonly 2,000 meters or one mile. For example, a recent study by Rabinowitz et al. [82] investigated health outcomes by surveying residents living within one kilometer, between one and two kilometers, and more than two kilometers from wells in Washington County, PA, regarding health symptoms they were experiencing. Several of the studies simply report sampling results for contaminants, including distance from the potential (gas infrastructure) source. To capture some of these values that might be experienced at the very closest distances, we also consider a distance of roughly 1,000 feet or less. Finally, for distances of less than 300 feet, we consider at-site exposures that residents with well pads very close to their homes might experience, as well as oil and gas workers working on a well pad.

One of the most commonly discussed risk pathways is groundwater contamination via casing and cementing failures [50], allowing methane and/or frac fluid and flowback to enter the groundwater aquifers overlaying the shale. According to a recent analysis of Pennsylvania Department of Environmental Protection violations data, unconventional well casing and cementing failures do occur regularly (in about 2 percent of wells inspected after initial drilling), and appear to occur more often in the northeastern part of the Marcellus (8.5 times higher risk than the rest of the state) [105]. The likelihood of groundwater contamination by methane from these types of failures appears correlated with distance, as Jackson et al. [106] found concentrations of methane in groundwater 6–23 times higher within 1 kilometer of an unconventional gas well than outside that distance. Other pathways include potential for accidents, leaks, or spills of frac fluid or wastewater fluids to infiltrate into groundwater from the surface. This risk pathway is particularly relevant for Broome (NY), Delaware (NY), Sullivan (NY), and Wayne (PA) Counties, whose population primarily (77–100 percent) uses groundwater for drinking [60].

Krupnick et al. [50] also interviewed experts who identified several risk pathways related to air contaminants emitted from activities in the drilling and production phases of development. Notably, there are air emissions associated with machinery and trucks during drilling and fracking; venting and flaring of methane during completion, production, and transport of gas; and emissions of volatile compounds from frac fluid and waste fluids (especially when stored in open impoundments). Many of these emissions are located near the well pad, but some are much more regionalized (truck traffic) or are associated with particular activities that may occur away from the well pad (e.g., volatile emissions from fluid or wastewater storage). Our analysis primarily considers distance from well pads, but health risks may be equally tied to distance from other activities, such as wastewater storage in impoundments.

Volatile air pollutants are of special concern in much of the health literature, and the first step in quantifying their risk is detecting their presence. Colborn et al. [107] detected dozens of VOCs, polycyclic aromatic hydrocarbons (PAHs), and carbonyls within 1.1 kilometers of a well pad, and noted health impacts, including endocrine disruption associated with exposures to many of the chemicals. A study completed for Forth Worth, Texas [108] detected many of the same chemicals at a slightly greater distance. Presence of these chemicals does not equate to health risk if concentrations are very low.

Studies by Macey et al. [109] and McKenzie et al. [7] computed health risks associated with exposure to the air pollutants (especially benzene, formaldehyde, and hydrogen sulfide) at a few distances from the gas development activities. They found potential for slight increases in cancer risk, and toxicity risk based on computing hazard indices for the measured concentrations of pollutants for chronic and subchronic exposures. More recently, some studies have been seeking evidence these exposures might lead to adverse health outcomes. A study by Rabinowitz et al. [110] indicated that there may be a relationship between dermal and upper respiratory symptoms (reported in health surveys) and distance from well pads. In addition, a study by Jemielita et al. [111] found that hospitalization rates in several Pennsylvania counties correlated with a number of active unconventional gas wells per square kilometer in patients' zip codes, especially for cardiology- and neurology-related hospital admissions.

Table 12. Health risk factors and impacts cited in literature, versus distance from gas development activities. Abbreviation and symbol definitions, as well as color-coding, appear below the table.

Environmental Health Risk	At-site <300 ft	<1000 ft	~0.5mi/1km	~1mi/2km	2 km or more	Studies
VOCs detected			14 (39/68)[a]		8 (45/59)[b]	[107], [108]
Benzene	A I C C4	C5	C5	C6		[109], [7]
Carbonyls detected			4 (8/12)[a]		8 (9/11)[b]	[107], [108]
Formaldehyde	A I C C5					[109]
PAHs detected			3 (12/16)[a]			[107]
Hydrogen Sulfide	A I	I				[109]
Cumulative excess cancer risk – air			5-6 per million	5-10 per million		[7]
Total Hazard Index – air, subchronic			0.4 - 5	0.1 – 0.2		[7]
Total Hazard Index – air, chronic			0.3 - 1	0.2 - 0.4		[7]
# health symptoms reported			3.27	2.56	1.60	[110]
Dermal symptoms (OR)			4.13	2.44 NS	Ref.	[110]
Upper respiratory symptoms (OR)			3.10	1.76 NS	Ref.	[110]
Silica exposure (% samples > PEL/REL)	47%/ 79%					[112]
Noise levels (dB)	*Max 102*	63 *(Max:95)*	54 *(Max:80)*	52 *(Max:74)*		[113]
Methane conc. in GW (times ref. values)		>6	6	Ref.	Ref.	[106]

VOC- Volatile Organic Compound; PAH – Polycyclic Aromatic Hydrocarbon; IRIS – Integrated Risk Information System; ATSDR – Agency for Toxic Substances and Disease Registry; MRL – Minimum Risk Level; GW - Groundwater; PEL – Permissible Exposure Limit; REL – Recommended Exposure Limit; OR – Odds Ratio; NS – Not statistically significant

[a] Chemicals detected in >50% of samples (# chemical detected/ # tested) [107]
[b] Chemicals detected in >90% of samples (# chemical detected/ # tested) [108]

Concentration exceeds ATDR MRL A Acute level I Intermediate Level C Chronic level

Excess IRIS cancer risk at C4 1/10,000 C5 1/100,000 C6 1/1,000,000 level

Odds ratio (increased likelihood relative to a reference ["Ref."] population) # Value times Ref. value #

Chemicals detected (air)	Health risks (air)	Health outcomes (symptoms)	Exposures To Noise & Dust	Ground-water risks	No or insufficient data	Moderate health risk	Lesser health risk	No significant health risk indicated

Occupational exposures are another category of exposure worth mentioning. Gas industry workers are likely to have higher exposures to volatile chemicals, due to their proximity to emissions sources. Additional health risks for workers and residents living close to well pads could result from worksite accidents; exposure to airborne silicates (dust) from the mixing of frac sand [112]; and elevated noise levels, which have been found to exceed 100 decibels (dB) at well pad sites during hydraulic fracturing and that persist at lower levels (roughly 60-80 dB) for 60 days or more [88, 113-114]. The noise levels decrease as distance from well increases.

Methodology

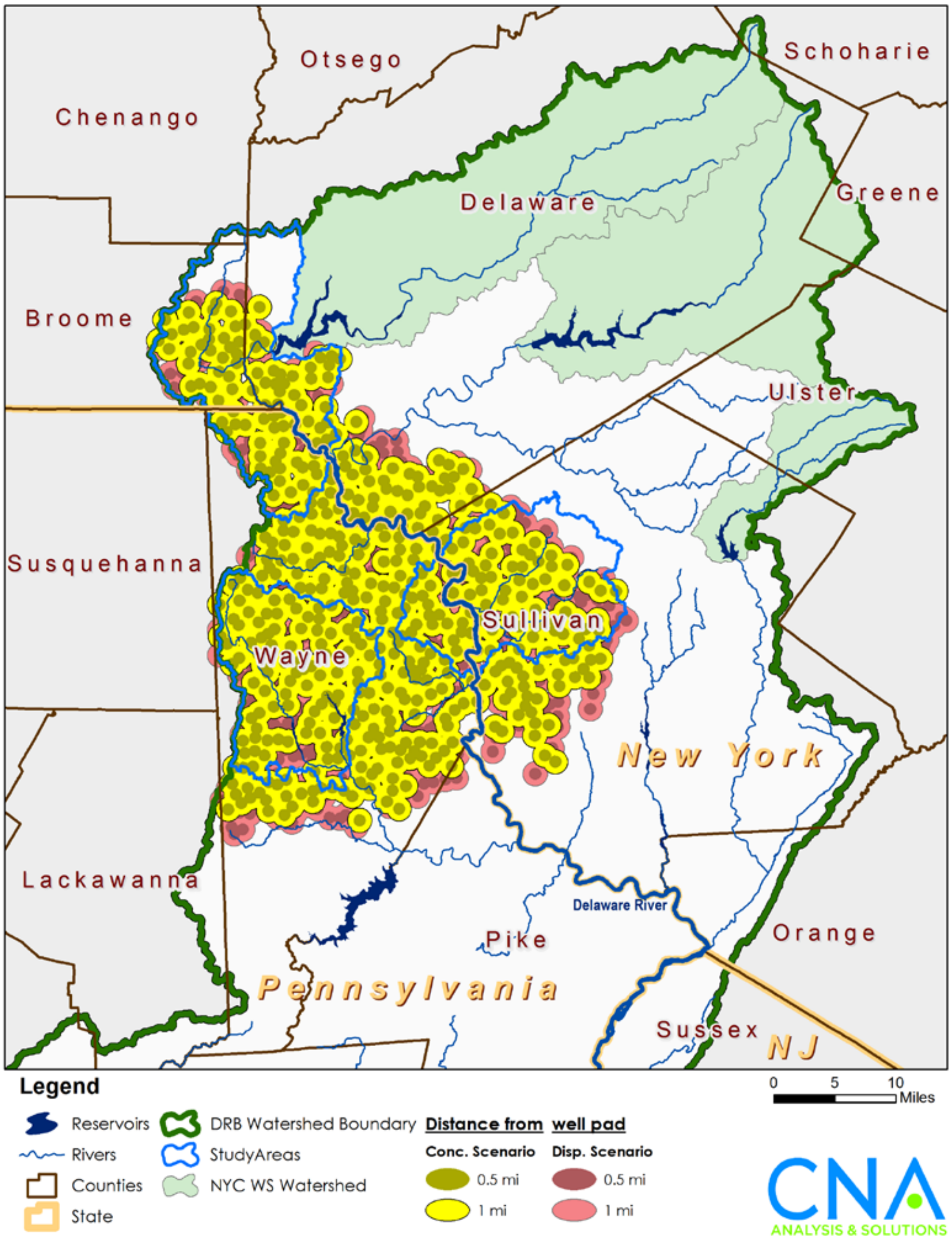
Until more rigorous data on health outcomes, exposure pathways, risk of exposure, and expected dosages become available, it is difficult to perform a detailed assessment of health impact, especially in a prospective analysis. Furthermore, actual risks of exposure depend strongly on both industry practices and regulations. Instead, this study identifies the potential population at risk based on distance to well pad locations identified in this study.

This study uses a buffer-analysis method to determine the approximate number of people and houses within several distances of the well pad commonly cited in the health literature. Using projected DRB well pad locations, we generated circular buffer polygons of 1,000 and 2,000 feet; 0.5 and 1 mile; and 1,000 and 2,000 meters in GIS software.

Figure 19 shows a map of the 0.5-mile and 1-mile buffers around well pads superimposed on county and study area boundaries. The yellow buffers are for the "concentrated" scenario. The red buffers show the additional area affected in the "dispersed" scenario (all of the yellow areas are also included). Similar buffers were created for 1,000 and 2,000 feet, and 1,000 and 2,000 meters.

Using the U.S. Census Bureau's Census Block data (the finest resolution available) and the associated 2010 Census housing and population counts, we computed the expected population within each buffer distance. We also intersected the census blocks with the buffer areas to determine overlap, and we determined population and house counts based on an assumption of uniform density within blocks (a reasonable assumption, since the blocks are relatively small). Finally, we performed additional intersections with county and study area boundaries to determine the distribution of potential impacts on populations.

Figure 19. Map of the 0.5-mile and 1-mile buffers around well pads superimposed on county and study area boundaries. Most of the population within the portion of the DRB with projected gas development would be within one mile of a well pad. At smaller distances, a smaller population would be affected. Except on a few fringes of the development area, there is not much difference between the concentrated and dispersed scenarios.



Note: NYC WS Watershed – Watershed area of New York City water supply reservoirs.

Results

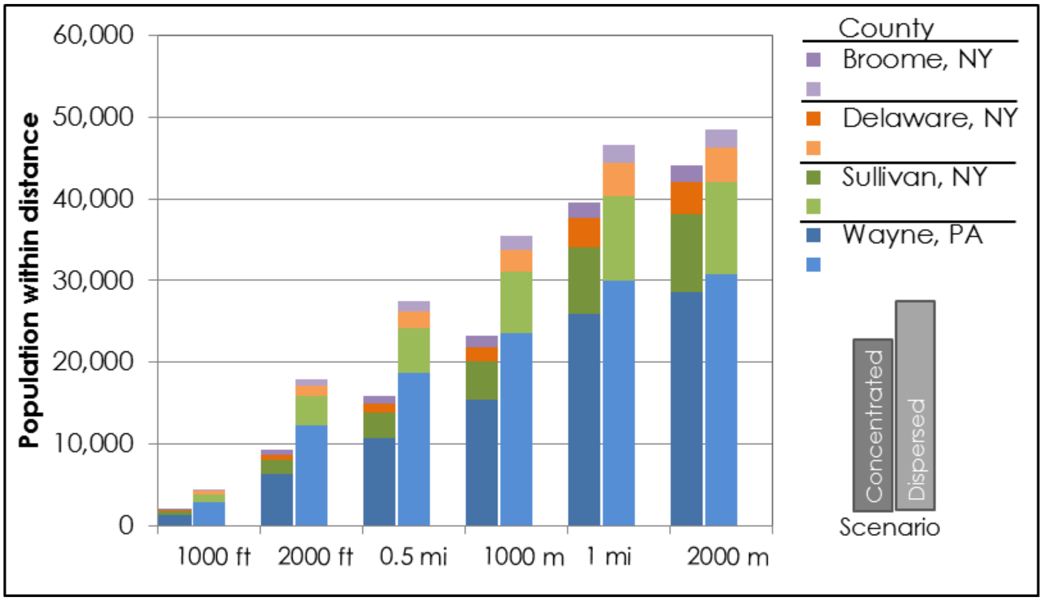
Hydraulic fracturing gas development with multiple wells per pad results in reasonably low overall well pad density, but fairly even distribution across the landscape. This even spacing results in large areas within reasonably short distances of the nearest wells. Figure 19 (previous page) illustrates the extensive portion of the study areas within a mile of the nearest well pad. While the portion of the DRB with well pads has few gaps in between well pads, the areas within a certain radius of well pads are more important to consider in the context of the portions of the study areas and the counties with population in the affected areas. Table 13 shows the area within 0.5 mile and 1 mile of the well pads in square miles, and as a portion of the study areas and most affected counties. The 0.5- and 1-mile distances are representative of the closer and farther distances referenced in the literature (see Table 12). As expected, the “dispersed” scenario results in more total area affected, because there are more well pads developed.

Table 13. Area within 0.5 mile and 1 mile well pad buffer, by county. The “dispersed” scenario affects a larger area, but at 1 mile, the gap between scenarios narrows. Units = square miles, % of county area.

		Within 0.5 mile		Within 1 mile	
County	**Scenario**	Area	%	Area	%
Wayne County, PA	Dispersed	362.1	*48%*	528.1	*70%*
751 sq. mi.	Concentrated	221.6	*30%*	472.3	*63%*
Broome County, NY	Dispersed	37.8	*5%*	68.7	*10%*
715 sq. mi.	Concentrated	24.2	*3%*	56.2	*8%*
Delaware County, NY	Dispersed	80.4	*5%*	134.9	*9%*
1,468 sq. mi.	Concentrated	52.3	*4%*	117.4	*8%*
Sullivan County, NY	Dispersed	130.0	*13%*	223.9	*22%*
997 sq. mi.	Concentrated	72.1	*7%*	177.7	*18%*

Figure 20 indicates the population (estimated by 2010 U.S. Census Block data) within several radii common to health-assessment literature. The population is shown by county and stacked to indicate cumulative population in the DRB. The adjacent bars show the difference between the “concentrated” (left) and “dispersed” (right) scenarios. Notably, at distances less than 1,000 meters, there is a significant difference between the scenarios. At distances of 1 mile or more, there is less difference between scenarios. Overall, 40,000–50,000 people live within about 1 mile (or 2 km) of the projected well pad locations.

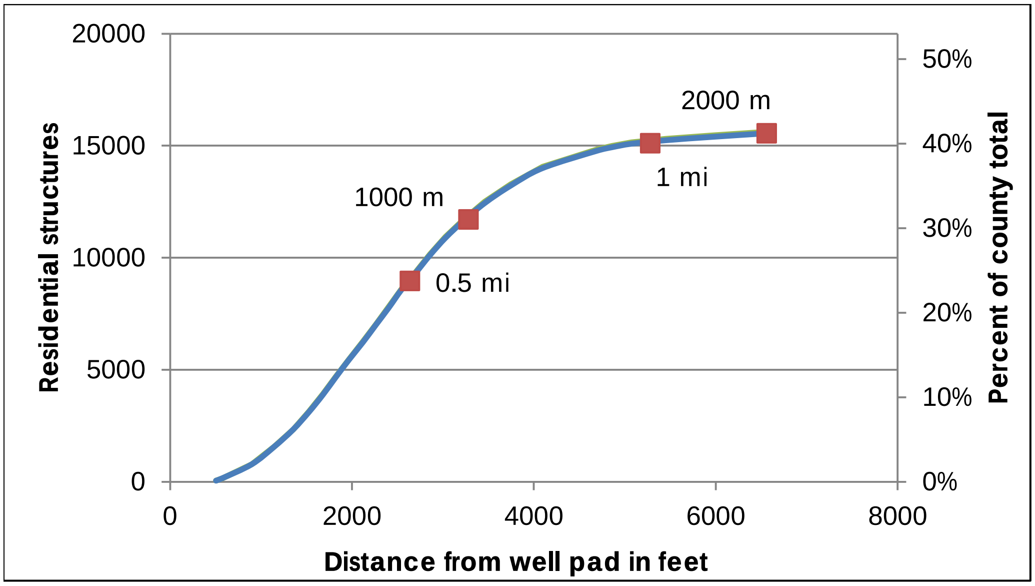
Figure 20. Population within several radii common to health-assessment literature. The population living within several distances (cited in health risk literature) of well pads depends on development scenario. At smaller distances, more people are affected with the "dispersed" scenario. Most of the population that could be affected lives in Wayne County, PA.



The majority of the population potentially affected lives in Wayne County, PA. For this county, we also assessed the portion of residential buildings within these distances using attributed building address points zoned as residential structures. In Figure 21, the horizontal axis shows the distance from well pad (in feet), the left axis shows total residential structures within that distance, and the right axis shows the percentage of the residential structures in Wayne County represented. Note that no structures are within 500 feet of any well pad based on exclusions used in siting the projected well pads. Roughly 40 percent of the residential structures in Wayne County would fall within one mile of a well pad.

These building level results contrast with the affected population results (slightly less than 60 percent of Wayne County's population of 52,000. The discrepancy may be due to more persons per household in the affected area, or some of the residential buildings being unoccupied or functioning as seasonal/vacation residences.

Figure 21. Wayne County residential structures within x distance (ft) of a well pad (total and percent of all county residential structures). Roughly 40 percent of the residential structures in the county would fall within one mile of a projected well pad location.



Discussion

Within the portion of the DRB projected to have gas development in this study, virtually the entire population falls within roughly one mile (or two kilometers) of the potential well pad sites identified. In total, roughly 45,000 people in the basin are within this distance, which can be compared to the population of nearby cities such as Easton (27,000), Wilkes-Barre (41,000), Bethlehem (75,000), and Scranton (76,000).

At smaller buffer distances (e.g., 2,000 feet, 0.5 mile, or 1,000 meters) representing the areas with most likely health impacts, less of the population is affected. At these buffer distances, there is a significant difference in affected population between scenarios. A smaller population is in close proximity to the wells in the "concentrated" scenario (eight wells per pad). However, the likelihood, dosage, and duration of exposure would likely be higher for those living within the smaller buffer distances for the "concentrated" scenario, due to the greater intensity and duration of gas extraction activities needed to develop eight wells per pad.

Chemical exposure may be higher still near other infrastructure not explicitly considered in this study, including wastewater impoundments or storage facilities, centralized waste-treatment plants, and gas compressors and pumping equipment. The longer-lived nature of these facilities and potential to handle material from multiple well sites may increase potential exposures for populations living near them. There may be some additional exposure to air pollutants, as well, due to regional air transport from active gas development areas in other parts of the Marcellus Shale, especially in Susquehanna, Bradford, and Wyoming Counties in Pennsylvania.

These estimates of population at risk within the DRB may be an underestimate of current and future population. The population estimates are based on the 2010 Census and include neither population change since that time, nor projected population growth through the completion of natural gas development.

It is important to remember that the well pad locations are not explicit predictions, so the exposure risks of specific properties should not be considered based on the results or maps presented. Across the study areas and this portion of the DRB, the calculated populations within the buffer distances give a reasonable first estimate of populations with potential for different levels of exposures should drilling begin.

Finally, this study does not assess the likelihood of occupational or vehicle accidents, spills, or the ability of the existing emergency response and healthcare systems to handle potential surges in demand. These questions are important to preparedness for local governments, but the projected population affected and maps of affected areas do provide a first step in assessing these needs.

Conclusions

This report presents an estimated projection of potential development of natural gas within the Delaware River Basin, concentrating on three study areas. The actual level of development would depend strongly on the actual production of the wells drilled in the DRB and on the price of gas within the energy markets, which can fluctuate rapidly. For the three study areas, we assessed potential environmental and health impacts using the best current understanding and data on well development. The results are intended to help decision-makers and the public understand the scale of the potential consequences.

We project ultimate development of the DRB portion of the Marcellus Shale could be as high as 4,000 wells, with development of up to about 500-1,000 well pads (based on an average of 8 or 4 wells per pad). This development would be most concentrated in Wayne County, PA. These estimates result from geospatial analysis performed with publicly available information on land and geological characteristics and on actual well-development data.

If natural gas development occurs as projected, natural gas infrastructure will become a widespread and prominent feature of the landscape in the Upper DRB. The repercussions of drilling and infrastructure-building activities would cover a broad range of issue areas, including forest fragmentation, water withdrawal and wastewater discharge, hydrologic and water-quality changes, air emissions, and potential health impacts. There may be others that are not included in this report. At a basic level, drilling rigs and truck traffic will have temporary effects near any one well pad, but over a long build-out, they could become common within the basin. The well pads, roads, and pipelines would most likely be long-term (30+ years)—or, in some cases, permanent—features of the landscape. Similarly, management of water, wastewater, and air emissions can create both short- and long-term impacts to the region.

This report specifically investigated potential consequences associated with land cover change, water and wastewater management, surface water hydrology and quality, air emissions, and affected population in three study areas across the DRB, considering significant projected well development. Key findings include the following:

- **Land cover change:** We found each well pad would cause on average 17-23 acres of land disturbance due to construction of well pads, roads, and pipeline rights-of-way. Pipeline construction would cause about 75 percent of land disturbance. In the most heavily developed areas that would be fracked, 2-3 percent of total area would be affected. The land cover types in each case study replaced by infrastructure include agriculture (43–63 percent) and forests (24–46 percent). By extrapolating results for our study areas, we estimate the total area required to fully develop the projected well pads, roads, and gathering pipelines in the DRB is between 18 and 26 square miles.

- **Forest fragmentation:** Pipelines and roads associated with gas development could have a noticeable effect on forest habitat in the study areas. Despite only clearing about 1 percent of forested area, the core forest area could decline up to 10 percent, while edge forest could increase by up to 8 percent. These changes have the potential to alter ecosystems and the relative abundance of forest species.

- **Water withdrawal:** If current water use and recycling trends hold, roughly 4.5 million gallons of water withdrawal would be needed for each well. These withdrawals would amount to 1.3 million gallons per day if averaged across the entire DRB over 30 years, but might reach 10 or more times higher during a peak year. Withdrawals during peak years could remove up to 70 percent of available flow from small streams during low-flow periods, but a negligible portion of flow if the withdrawal occurs on mainstem rivers during average-flow conditions.

- **Wastewater discharge:** Wastewater management would be an important issue, due to the high pollutant loadings in untreated flowback and brines. The amount of wastewater reuse, and types of treatment and disposal methods used for natural gas wastewaters would have a strong influence on the pollutant loadings that may enter the basin. If there were no wastewater reuse and all wastewater were treated to exactly meet effluent standards, in-stream concentrations of barium and strontium could increase by up to 500 percent from baseline concentrations at low-flow periods. Total dissolved solids, chloride, and sulfates would see smaller increases. Similar to water withdrawals, the magnitude of these consequencess may vary considerably by time and location, but these impacts would occur over a duration of 30 years.

- **Hydrology and surface water quality:** Changes in land cover associated with infrastructure development could lead directly to hydrologic and water-quality changes for the DRB. The initial land clearing could leave the watershed especially vulnerable to increased upland erosion and sedimentation loadings in the short-term (up to 140 percent increase over baseline). Following development, the upland changes in runoff and erosion would persist at lower levels (around 15 percent above baseline). The land cover changes would also change hydrology by increasing runoff by 1-3 percent during peak flow periods, and reducing groundwater recharge.

- **Air quality:** Industrial processes associated with natural gas development could produce emissions that would degrade the air quality in the DRB. In addition to the contributions from well site–development and well completion, the installation of compressor stations could present significant increases (as much as doubling) in NO_x emissions for three of the four DRB counties. The contributions to VOC, SO_x, and PM emissions from annual shale gas development did not appear as significant compared to other activities in these counties at the county-wide scale (note that this analysis did not look at the potential impacts of these emissions at the local level). Development in the DRB would contribute methane emissions from leakage throughout the process, though small in the context of total emissions from the Marcellus Shale.

- **Affected population:** Due to the relatively even spacing of the projected well pads in the DRB, a large percentage of the population in the affected area would live within one mile of the nearest well, which may present certain health risks, based on current scientific literature. At full development, about 45,000 people in the DRB would live within about one mile of the nearest projected well pad location. Wayne County, PA would be most affected, with 30,000 people (nearly 60 percent of its population) potentially living within one mile of a well pad. At smaller distances of about a half-mile, roughly 15,000 to 25,000 people in the DRB could be affected, depending on the number of wells per pad. Increasing the number of wells per pad from four to eight would reduce the population affected at the closest radii, but may result in longer duration of some exposures due to more wells developed.

Of these findings, change in land cover and associated impacts to forests, hydrology, and water quality appear the most difficult to avoid. The wastewater and air quality risks could pose significant management challenges. The potential health impacts require more study to understand extent and risk levels.

These findings do not cover the full range of potential impacts that may occur if gas development does occur. Instead, the results offer an initial view of the overall level and potential range of impacts. The development projections assume a high degree of development that may never be reached, but the maximum-year development projections for a given year are possible. The scenarios presented focus on identifying conditions when the consequences may be highest and on what the corresponding level of impact would be, averaged across a study area (either county or watershed).[8] In assessing risk, it is this type of information that is most useful for planning.

[8] Of note, this analysis does not account for the maximum potential impacts to sites that may occur within the study areas as a result of locally high development densities, accidents, or variations in practices by gas drilling operators. If development begins, the range of potential impacts could be expected to vary widely through time and across geography.

Appendix A: Chemicals in Natural Gas Wastewaters

The "Impacts on Water and Wastewater Management" chapter investigates a limited set of five contaminants that have effluent-discharge concentration limits under Pennsylvania regulations[69] for wastewater treatment facilities built after 2010 that treat natural gas wastewater. Analyses that have tested water quality of natural gas wastewaters have documented the presence of many more potential contaminants. In Table 14, we have assembled data from 13 studies on the concentrations of contaminants in flowback and brine wastewaters.

The values for flowback and brine reported reflect the average of median values across studies. The range reflects the low and high values reported in either flowback or brine wastewater samples reported in the studies. There have also been some studies of wastewater treatment plant effluent where effluent discharge concentrations have been measured. We include these values in the final column, but note that these facilities represent older industrial wastewater treatment plants that are not required to meet the 2010 Pennsylvania regulations. For cells left blank, no data were available.

Table 14. Pollutants measured in natural gas wastewaters. For cells left blank, no data were available. Units = milligrams per liter, unless otherwise noted.

	Pollutant	Flowback	Brine	Range	Industrial WW effluent
Primary (regulated)	Total Dissolved Solids (TDS)	73,000	205,600	38,500 – 261,000	123,500
	Chloride (Cl)	54,600	99,600	19,600 – 174,700	84,300
	Barium (Ba)	1,017	8,281	4 – 84,300	20
	Strontium (Sr)	1,187	5,225	350 – 4,800	2,005
	Sulfate (SO_4)	30	55	2.4 - 300	810
Physical and Nutrients	Turbidity	230	207	11 – 3,330	
	pH	6.6	6	4.7 - 7.2	
	Specific Conductance [µmho/cm]	138,000	300,800	6,800 – 710,000	
	Alkalinity	138	70	49 - 327	254
	Acidity			<5 - 470	
	Total Organic Carbon	62.8	984	4 – 19,250	
	Dissolved Organic Carbon	114	43	5 - 700	
	Chemical Oxygen Demand	3100	8,530	195 – 71,000	
	Biochemical Oxygen Demand	100	448	37 - 2070	
	Hardness (as $CaCO_3$)	22,100	34,000	630 – 95,000	
	Ammonia (NH_3 as N)	71	125	29 - 200	68
	Total Kjehldahl Nitrogen	86	116	38 - 200	
	Nitrate (as N)	0.02		0 - 1.2	
	Nitrite (as N)	1.2		0.06 - 29.3	
	Total Phosphorus (as P)	1.3		0 - 8	
Halides (salts)	Bromide (Br)	559	730	108 – 1,200	740
	Fluoride (F)			<0.05 - 50	
	Iodide (I)	6.3		0.2 - 19.3	21
Metals	Sodium (Na)	23,500	37,700	10,700 – 95,500	27,300
	Potassium (K)	49	351	2.4 - 351	
	Calcium (Ca)	7,280	16,900	1,400 – 23,500	13,950
	Magnesium (Mg)	735	1,410	140 – 1,600	941
	Boron (B)	12.2		3.1 - 97.9	
	Chromium (Cr)			0.005 - 151	
	Manganese (Mn)	5	9	1.9 - 18.6	
	Iron (Fe)	45.1	107	13.8 - 242	
	Lead (Pb)	0.01		0 - 0.6	

	Pollutant	Flowback	Brine	Range	Industrial WW Effluent
Hydrocarbons	Oil and Grease	24.2		4.6 - 655	
	Benzene [µg/L]	150			8
	Ethylbenzene [µg/L]	53			5
	Toluene [µg/L]	622			46
	Xylene [µg/L]	699			32
	Styrene [µg/L]	11			
NORM	Naturally Occurring Radioactive Materials [pCi/L]		2460	0 - 18000	

Sources: [39-43, 62-68, 88]

Notes: µg/L = micrograms per liter; pCi/L = picocuries per liter; µmho/cm = micromhos per centimeter

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Appendix B: Stream Gages

We used the following stream gages operated by the U.S. Geological Survey (USGS) to develop streamflow statistics for the chapter of this report titled "Impacts on Water and Wastewater Management." Table 15 identifies the stream gages we used, including their record length and drainage area. Table 16 presents several flow statistics (especially low-flow statistics) that we used for computing water and wastewater impacts. The flows are presented in units of million gallons per day, per square mile.

Table 15. USGS stream gages used in this study.

Study Area	ID (this study)	Type [a]	USGS ID	Name	Record Length	DA (sq.mi)
1	1.1	Small Stream	01426000	Oquaga Creek at Deposit, NY	1940–1973	67.6
	1.2	Mainstem	01426500	West Branch Delaware River at Hale Eddy, NY	1912 – 2013	595
2	2.1	Small Stream	01428750	West Branch Lackawaxen River near Aldenville, PA	1986–2013	40.6
	2.2	Mainstem	01430000	Lackawaxen River near Honesdale, PA	1948–2013	164
3	3.1	Small Stream	01427500	Callicoon Creek at Callicoon, NY	1940–1982, 2000–2011	110
	3.2	Mainstem	01427510	Delaware River at Callicoon, NY	1975–2013	1820
DRB	4	Mainstem	01434000	Delaware River at Port Jervis, NY	1960–2013	3070

Source: USGS, compiled by CNA.

[a]. Small stream gages have their drainage area (DA) entirely within the study areas; by contrast, mainstem gages include some additional upstream area (except 01430000).

Table 16. Daily flow statistics for the stream gages used in this study. Units = million gallons per day, per square mile.

ID	Q7-10[a]	5% [b]	20% [c]	Median (JAS)[d]	Median (50%)	Average
1.1	0.017	0.034	0.105	0.147	0.459	1.010
1.2	0.056	0.106	0.228	0.657	0.566	0.950
2.1	0.096	0.132	0.287	0.362	0.732	1.379
2.2	0.053	0.091	0.229	0.279	0.631	1.163
3.1	0.037	0.071	0.176	0.235	0.511	1.039
3.2	0.194	0.259	0.362	0.434	0.558	1.058
4	0.164	0.282	0.366	0.426	0.636	1.061

Source: USGS, calculations by CNA.

[a] Lowest seven-day average flow expected to occur once every 10 years

[b] Fifth percentile flow. Also referred to as the Q95

[c] Twentieth percentile flow, also referred to as the Q80

[d] JAS = July, August, September

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