Response to Key Technical Issues Requested by the Delaware River Basin Commission on its Proposed New 18 CFR Part 440 Review

Hydraulic Fracturing in Shale and Other Formations:

SUBCHAPTER B – SPECIAL REGULATIONS

Prepared at the request of the

American Petroleum Institute

Analysis By:

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DISCLAIMER

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Abbreviations and Acronyms

$\%R_0$	vitrinite reflectance
ABR	Approval-by-Rule
ALL	ALL Consulting
APE	anticipated production extent
API	American Petroleum Institute
bbl	barrel
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bgals	billion gallons
BLM	Bureau of Land Management
BMP	best management practice
CWT	centralized waste treatment
DAF	dissolved air filtration
DRB	Delaware River Basin
DRBC	Delaware River Basin Commission
ED	Electrodialysis
EDR	Electrodialysis Reversal
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EV	Exceptional Value
gal	gallon
gals/d	gallons per day
GIS	geographical information system
GOR	gas-to-oil ratio
HQ	High Quality
HVHF	high volume hydraulic fracturing
KCl	potassium chloride
LSM	low slump mortar
Mcf	thousand cubic feet
mg/L	milligrams per liter
Mgal/d	million gallons per day
Mgals	million gallons
MVR	Mechanical Vapor Recompression
NFR	nano-particle friction reducer
NGDP	Natural Gas Development Plan
NGL	natural gas liquids
PA DEP	Pennsylvania Department of Environmental Protection
ppm	parts per million
psi	pounds per square inch
PWSA	Public Water Supply Agencies
RFDS	Reasonable Foreseeable Development Scenario
RO	Reverse Osmosis
ROW	right-of-way
SAB	Science Advisory Board
SPCC	Spill prevention control and countermeasure
SPW	Special Protection Waters
SRB	Susquehanna River Basin
SRBC	Susquehanna River Basin Commission
Tcf	trillion cubic feet
TDS	total dissolved solids
TOC	total organic carbon
TS	total solids
TVR	Thermal Vapor Recompression
USGS	U.S. Geological Survey
UV	ultraviolet
VOC	volatile organic compound
WWF	Warm Water Fisheries

Executive Summary

The Delaware River Basin Commission (DRBC) published proposed rules on November 30, 2017, which would prohibit high volume hydraulic fracturing (HVHF*) within the Delaware River Basin (DRB). These rules would also strengthen DRBC policies to discourage importation of wastewater and exportation of water, and include rules regarding the inter-basin transfer of water and wastewater related to hydraulic fracturing. The draft rules also include requirements for safeguarding that the treatment and disposal of produced water from hydraulic fracturing does not impair or conflict with the preservation of the waters of the basin for uses in accordance with the DRBC Comprehensive Plan.

To investigate the impact of these proposed rules, an understanding of the amount of anticipated development needed to be prepared. An examination of the viable oil and natural gas resources within the DRB as outlined by the U.S. Energy Information Administration (EIA) was conducted. This examination suggested that the anticipated production extent (APE) would be limited to six northeastern Pennsylvania (PA) counties (Carbon, Lackawanna, Luzerne, Monroe, Pike, Wayne) where thermally mature Marcellus and Utica shales underlie approximately 1,787 square miles (1,143,680 acres).

A Geographical Information System (GIS) analysis was conducted on the APE to assess the amount of surface acreage that would be available to development given the previous DRBC Article 7 setback, landscape, and approval-by-rule (ABR) restrictions, issued in 2010. This analysis indicated that only ~897 square miles would be available for development without a variance (approval for well pad placement would be either by docket or ABR with an approved Natural Gas Development Plan (NGDP)). Of these ~897 square miles, ~696 square miles would be subject to forested site constraints, leaving only ~201 square miles for development within the APE.

To estimate the future oil and gas exploration and development activities that might reasonably be expected to occur in the DRB over the next 10 years, an analysis of the PA drilling permits issued and wells drilled between 2013 and 2017 within counties in proximity to the DRB was conducted. The forecast was based on the area's geology and historical and present activity, as well as factors such as economics, technological advances, access to oil and gas areas, transportation, and processing facilities. The analysis estimated a development potential of 40 wells drilled each year for the next ten years or 400 wells over the next decade.

The current hydrologic conditions in the Upper Region of the DRB were evaluated to determine the impact water withdrawals for HVHF might have on the current uses and environment. The DRBC reports that the hydrologic conditions over the past few years have been below-normal for precipitation in the Upper Region and there have been periodic reservoir releases conducted to augment late year streamflow lows and groundwater levels experiencing fluctuations below the 25th percentile. This reduced precipitation coupled with the reported normal withdraws can add stress to the watersheds.

* The oil & gas industry generally does not use the term "high volume hydraulic fracturing," preferring to call the process merely "hydraulic fracturing." However, the DRBC uses this term in its material and therefore we echo that usage in this report in order to maintain consistency and make it clear for the DRBC and other reviewers.

Water use within the APE was calculated using data provided by the U.S. Geological Survey (USGS) for the portion of the counties with underlying shale. This data indicated that a total of 54.68 million gallons per day (Mgal/d) or 19.97 billion gallons annually are currently being withdrawn from the APE within the six counties by various sectors. The DRBC, on the other hand, reports that the Upper Region withdraws about 1.5 Mgal/d for consumptive use and that that amount represents an estimated 1.0% of the withdrawals for the region. Based on the DRBC data, the daily withdrawal in the Upper Region would be approximately 150 Mgal/d.

The average quantity of water being used in HVHF treatments was examined using FracFocus disclosures (2013-2017) from Marcellus and Utica wells drilled in PA. The 5-year average volume for all disclosures over this period is 11,172,772 gallons (gals), for Marcellus-only disclosures 11,132,875 gals, and for Utica-only disclosures 13,145,825 gals. The increase in base fluid volume from the 3.5 Mgals per fractured well used in the 2011 report is likely a result of longer lateral wellbore lengths, greater depths drilled, optimization of multistage fractures, and new fracture methods being employed. Using the 5-year average volume and the estimated development rate of 40 wells per year indicates that a total of ~447 Mgals (1.22 Mgal/d) would be withdrawn for natural gas development within the APE annually. The 1.22 Mgal/d represents 2.23% of the estimated USGS daily withdrawal for the APE and only 0.81% of the DRBC reported withdrawals for the Upper Region.

Protecting water within the APE may involve the application of several best management practices (BMPs) suited to site-specific conditions as the entire area is designated as Special Protection Waters (SPWs). With this in mind, this report addresses the advances in spill protection, containment, and countermeasures to prevent surface and ground water adulteration from accidental hydrocarbon and chemical spills during all stages of the hydraulic fracturing water cycle. To support this discussion, a review of the EPA Draft and Final reports which investigated the impacts from the hydraulic fracturing water cycle on drinking water resources in the United States is included, as well as an analysis of the environmental compliance violations in Susquehanna County, PA. The analysis reviewed 5-years of data (2013-2017) from this adjacent county undergoing prolific development as an indicator of potential development incidents for the APE. There are ~1,431 unconventional wells operating in Susquehanna County of which 781 have been drilled and hydraulically fractured from 2013-2017. The data revealed 82 incidents related to potential surface- or ground-water impacts: 76 spills, 2 leaks, 2 lack of erosion control, and 2 well integrity issues with migrating gas. Of these 82 incidents involving the release of materials, only six were cited for a 401 violation indicating that the discharged substance resulted in impacts to the Waters of the Commonwealth. These six events account for 0.42% of the total operating unconventional wells, 0.77% of the drilled wells in 2013-2017, and 8.45% of the locations with incidents. Applying these percentages to the projected development rate for the DRB indicates that 3.63 (9.09% of 40 wells) release events might occur per year and there is less than a 0.5% chance that one of those events would result in impacts to the Waters of the Commonwealth

To quantify the potential surface disturbances from projected HVHF development on the available unrestricted surface of the APE area (201 sq. miles), the likely placement of well pads and the number of wells on each pad was considered. The development scenario suggests wells would be drilled at a rate of ~5 wells per year per county with the exception of Wayne County where ~15 wells per year are estimated. It was also expected that operators would take a cautious approach to development in this thermally mature region and develop multi-well pads with at least five wells per pad initially. Using this approach it was determined that from slightly less than 40 to a maximum of 80 well pads would be developed over the 10-year period depending on the number of wells per pad. The landscape or surface disturbances associated with these pads was calculated to be 1,200 acres for the 5-well per pad scenario and 600 acres for the 10-wells per pad scenario over the whole 10 years or about 120 to 60 acres per year. Factoring in restoration activities and mitigation measures reduced the residual altered acreage for the two scenarios to 400 acres and 200 acres respectively.

An economic analysis based on the estimated development rate (40 well/year) was conducted to identify future significant energy and economic benefits. Based on 2017 data, each well drilled in the APE is estimated to produce a total of 14.3 Bcf of natural gas over the first ten years of production. Using a range of plausible wellhead gas prices, that 14.3 Bcf would be worth from $27 million to $57 million. Using our estimate of 40 wells drilled per year, the production from those 40 wells would be valued at between $1.1 billion and $2.2 billion over ten years. Royalties collected by landowners annually from those 40 wells would be from $143 million to $458 million. State income taxes on those royalties would range from $4 million to $14 million per year. Drilling permit fees collected by the state for 40 wells per year would amount to $156,000, or $1.5 million over ten years. Lease bonus payments are difficult to estimate because they require a variety of assumptions, but they could conservatively range from $6 million to $64 million on land that is not restricted from development.

Finally, a review of existing water treatment technologies was conducted to capture the current technology and consider what might be available for use in the DRB. The review determined that a multitude of technologies exist that are designed to remove a variety of constituents from produced water, and that can treat a wide range of produced water quality. The product of these treatment technologies can range from clean water that meets drinking water standards to brines that can be recycled for various uses, including for fracturing additional wells, to solids that can be disposed of or recycled easily. Recycling the flowback[*] and produced water has a number of benefits, including offsetting new source water demand for scarce fresh water resources, preserving that water for other uses, and reducing the volume of waste that must be disposed. Wastes from these treatment technologies are relatively low volume and can be disposed of safely. Flowback and produced water can also be recycled for agricultural and industrial uses, replacing volumes of fresh water that would otherwise be used in those sectors. In areas where any discharge of produced or treated water is a major concern, options that result in zero discharge of water, such as evaporation ponds and crystallization, can allow hydraulic fracturing to take place while addressing those concerns.

In conclusion, the development of hydrocarbon resources in the APE of the DRB would be limited to a six county area in the Upper Region where thermally mature Marcellus and Utica shales would most likely produce dry gas; there are an estimate 201 square miles or 128,640 acres available for development under the old Article 7 rules without restriction; the reasonably expected development rate would be approximately 40 wells per year; current hydrologic conditions in the

[*] The oil & gas industry generally does not use the term "flowback water" to refer to fluids generated from a well. Rather the term "flowback" is used to refer to a process and all fluids generated from a well are recognized as "produced water." However, the DRBC uses this term in its materials and therefore we echo that usage in this report in order to maintain consistency and make it clear for the DRBC and other reviewers.

Upper Region of the DRB have been strained due to reduced annual precipitation over the past few years; the water withdrawn for HVHF in the APE is estimated at ~447 Mgals annually or 1.22 Mgal/d representing only 2.23% of the current estimated USGS daily withdrawal for the APE or only 0.81% of the DRBC reported withdrawals for the Upper Region; the compliance violations in Susquehanna County over the past 5-years indicate that 3.63 release events might occur per year in the APE and there is less than a 0.5% chance that one of those events would potentially reach the Waters of the Commonwealth; the landscape disturbances associated with pad development would range from 400 to 200 acres (0.625-0.3125 sq. miles) over the 10-year development period following restoration activities; state and private revenues generated by the development of natural gas would be significant with estimates ranging from $148 million to $475 million annually; and water treatment technologies are available that would reduce withdrawals, recycle produced water, and eliminate discharges.

The analysis presented in this report demonstrates that the potential risks to the environment posed by unconventional gas development are controllable and negligible and are offset by considerable potential benefits, and that a prohibition of HVHF in the DRB is not justified. The reasonable rate of development estimated, the focus on dry gas, the anticipated small surface footprint, the comparatively minor amount of water that would be withdrawn, the advances in pad containment and spill management that industry has made, and the projected economic benefits of unconventional gas development, all lead to this logical conclusion. Furthermore, given the exceptionally low number of violations in nearby Susquehanna County over a period that saw nearly four times as much drilling activity as is anticipated for the APE, as well as the water treatment technologies available for recycling and zero discharge that are protective of the environment, the DRBC should reconsider its proposed regulations regarding oil and gas development in order to better balance the risks and benefits of such development in accordance with the DRBC Comprehensive Plan.

1 Introduction

The Delaware River Basin Commission (DRBC) published proposed rules on November 30, 2017, which would prohibit high volume hydraulic fracturing (HVHF[*]) within the Delaware River Basin (DRB). These rules would also modify DRBC policies to discourage importation of wastewater and exportation of[1] water, and include rules regarding the inter-basin transfer of water and wastewater related to hydraulic fracturing. The draft rules also include requirements for treatment and disposal of produced water from hydraulic fracturing, which does not impair or conflict with the preservation of the waters of the basin for uses in accordance with the DRBC Comprehensive Plan.

This report contains the results of the analysis of the risks and benefits related to DRBC's proposed rule, as well as an updated analysis of potential environmental impacts and regulatory restrictions on oil and natural gas development within the portion of the DRBC that is within the State of Pennsylvania. The portions of the DRBC that contain hydrocarbon-bearing deposits in New York State are not addressed due to the hydraulic fracturing moratorium issued by New York State. The report addresses the following four major topic areas:

- **Proposed Rules Effects on Water and Land Use:** The proposed rules as issued November 30, 2017, prohibit HVHF in hydrocarbon-bearing formations; require DRBC approval to transfer water outside the DRB for use in hydraulic fracturing or to transfer produced water or centralized waste treatment (CWT) wastewater into the basin; and set policy that there be no measurable change in existing water quality. In light of the proposed prohibitions and policies, the previous impact and restriction analyses ALL Consulting prepared (April 2011) were updated to compare new reasonably foreseeable development levels with the previous (Article 7) DRBC setback and siting restriction guidelines versus no development at all. The new reasonably foreseeable development levels are based on updated thermal maturation data for the Marcellus and Utica shales within the DRB as well as the advanced drilling and fracturing techniques currently being employed in Pennsylvania.
- **Economic Analysis:** This analysis is based on the revised rate of development, the annual number of exploration, development and operational jobs and wages as well as the projected gas production and income projected for lease and royalty payments, which would be anticipated for that exploration and production within the DRB. The revenue from fees paid by the oil and gas industry have also been identified, based on the projected development within the DRB. Additionally, the substantial indirect financial impact the oil and gas industry has on other industries from the quantity of goods and services purchased from these firms is discussed.
- **Landscape Alterations:** Oil and gas development coupled with hydraulic fracturing has raised concerns that the activity and resulting disturbances would alter landscapes and pose unacceptable risks to high value water resources by impacting the drainage areas of Special

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Protection Waters (SPW). These concerns are sometimes put forth prior to rigorous scientific evaluation of cause-and-effect relationships or the consideration of best management practices, technological improvements, and required mitigation measures being enforced. Advances in horizontal drilling and hydraulic fracturing have been identified and correlated so the average anticipated environmental disturbances could be evaluated in light of the projected development rate for affected counties within DRB and SPW.

- **Produced Water Treatment Technologies**: Produced water handling methodology depends on the composition of produced (influent) water, location, quantity and the availability of resources. This analysis reviewed current produced water technologies, including those that would be applicable for use in the eastern United States. In addition, the analysis took into account the technologies advantages and disadvantages, including their applicability for different kinds of produced water, achievement of targeted output criteria, the quantity and toxicity of the waste stream, and infrastructure considerations. No-discharge technologies were also reviewed as preventing or eliminating discharges to the basin's waters would satisfy the DRBC's goals to conserve, protect, maintain and improve the quality of the basin's waters. Recycling and the use of treated water in applications outside of the oil and gas industry is also discussed.

2 Proposed Rules Effects on Water and Land Use

The DRBC proposes to amend their *Special Regulations* by adding a section on hydraulic fracturing that would prohibit HVHF in hydrocarbon-bearing formations. The DRBC indicated that the prohibition is necessary "to effectuate the Comprehensive Plan for the immediate and long term development and use of the water resources of the Basin, and to conserve, preserve and protect the quality and quantity of the Basin's water resources for uses in accordance with the Comprehensive Plan."[2] Over the past half-century the DRBC has managed the DRB water resources through the Comprehensive Plan by issuing policies and regulations that established in-stream water quality standards throughout the Basin, prohibiting degradation of groundwater, and providing special protection to the non-tidal segment of the Delaware River to preserve its high water quality and water supply values. The DRBC took these measures to meet public and private needs for drinking water, recreation, power generation, and industrial activities. Therefore, to understand if HVHF poses a threat to these established needs and activities it is necessary to gauge the level of development that is being prohibited and the resulting water and land use that might occur if oil and gas development were to proceed. This being the case, the following analysis estimates the reasonable foreseeable development level and rate of development for the Marcellus and Utica shale within the DRB, as well as the water and land use needs of the projected development. These levels, rates, and quantities have been compared to existing water and land use for the domestic and industrial activities within the same area overlying the Marcellus and Utica shales in the DRB.

It should be noted that the State of Pennsylvania, in addition to many other states, has regulations that control the responsible development of shale gas resources, including those that would be developed within the DRB. It is generally recognized that the costs and risks as well as benefits of

HVHF primarily fall on a state, and the states with a history of oil and gas regulatory experience are better equipped to regulate HVHF. Many of the states, including PA, have adopted regulatory systems that fit current conditions and have a track record to prove it.[3] The Commonwealth of PA via their PA DEP has successfully managed Marcellus and Utica shale development in the Ohio River Basin (ORB), Susquehanna River Basin (SRB) and can do so in the DRB. Additionally, the PA DEP has multiple layers of permitting, inspection and enforcement plus industry has multiple layers of Best Management Practices (BMP). Given the rapid and increasing development of shale gas over the past decade PA has done an admirable job balancing the environmental and public safety issues with its responsibility to allow development of its shale hydrocarbon resource.[4]

2.1 Land

2.1.1 Potential Development Area

Since the previous analysis (April 2011) and associated reasonable foreseeable development rates were estimated, much has been discovered about the Marcellus and Utica shales within the DRB. The U.S. Energy Information Administration (EIA) has added and updated geologic information and maps of the Marcellus and Utica shale plays.[5,6] The categorization and apprising of the geologic features by the EIA since 2011 for the Marcellus and Utica shales include delineated thicknesses (isopach), contoured elevations of the formation tops (structure), paleogeography alignments, and tectonic structures (regional faults and folds, etc.), as well as play boundaries, well location, and initial wellhead yields, oil-to-gas and gas-to-oil ratios (GOR), of Marcellus and Utica wells producing from January 2000 and January 2004 through December 2016 respectively.

The play boundaries and high productivity areas are controlled by key geologic criteria that include thermal maturity, total organic carbon (TOC) content, formation thickness, porosity, depth, pressure, and the ability of the formations to be hydraulically fractured. Chief among these geologic criteria is thermal maturity as crude oil and natural gas are produced by heating the organic materials (i.e., kerogen) found in organic-rich rocks, usually shales. When these rocks are exposed to increasing temperatures and pressures over long periods of time, the organic materials in them are transformed by the heat into a waxy substance, i.e., kerogen. As the temperature rises progressively, the kerogen becomes oil, oil becomes wet gas, and wet gas becomes dry gas. The extent that the organic material has been converted can be measured by the thermal maturity.

To estimate thermal maturity in shales, core samples are taken and the vitrinite reflectance ($\%R_0$) is measured. Vitrinite reflectance is a measure of the percentage of light reflected from the vitrinite maceral in a sedimentary rock.[7] Oil and gas zone boundaries are often established using vitrinite reflectance data; however, the boundaries are approximate and can vary according to kerogen type. The temperature arrays favorable to transforming organic material to oil and natural gas are denoted as the oil window and the gas window, respectively. The average $\%R_0$ values for the different hydrocarbon windows in Marcellus and Utica shales are presented in **Exhibit 1**.[8,9]

EXHIBIT 1: AVERAGE PERCENT VITRINITE REFLECTANCE IN MARCELLUS / UTICA SHALES

Hydrocarbon Windows	Marcellus	Utica
Immature	$\%R_0$ <0.6	$\%R_0$ <0.6
Oil Prone	$\%R_0$ 0.6 – 1.3	$\%R_0$ 0.6 – 1.1
Wet Gas Prone	$\%R_0$ 1.3 -2.0*	$\%R_0$ 1.1 -1.4
Gas Prone		$\%R_0$ 1.4 – 3.2
Over Mature	$\%R_0$ > 2.0	$\%R_0$ 3.2 – 4.93

In the Marcellus Shale the $\%R_0$ generally increase in a southeastern direction, ranging from 0.5% R_0 to more than 3.5% across the Appalachian basin (see **Exhibit 2**). In the Utica, the play becomes over mature with $\%R_0$ values up to 4.93 as the production trends indicate in the eastern portion of the play (see **Exhibit 3**). Both **Exhibits 2** and **3** also show the distribution of production across the plays in terms of initial yields. Yields represent the ratio of either oil-to-gas (**Exhibit 2**) or GOR (**Exhibit 3**) produced from a well. The distribution of oil and natural gas in a formation is mainly controlled by the thermal maturity of a rock, which is an indication of potential hydrocarbon generation.

EXHIBIT 2: THERMAL MATURITY OF MARCELLUS SHALE AND INITIAL YIELDS (OIL-TO-GAS RATIOS)

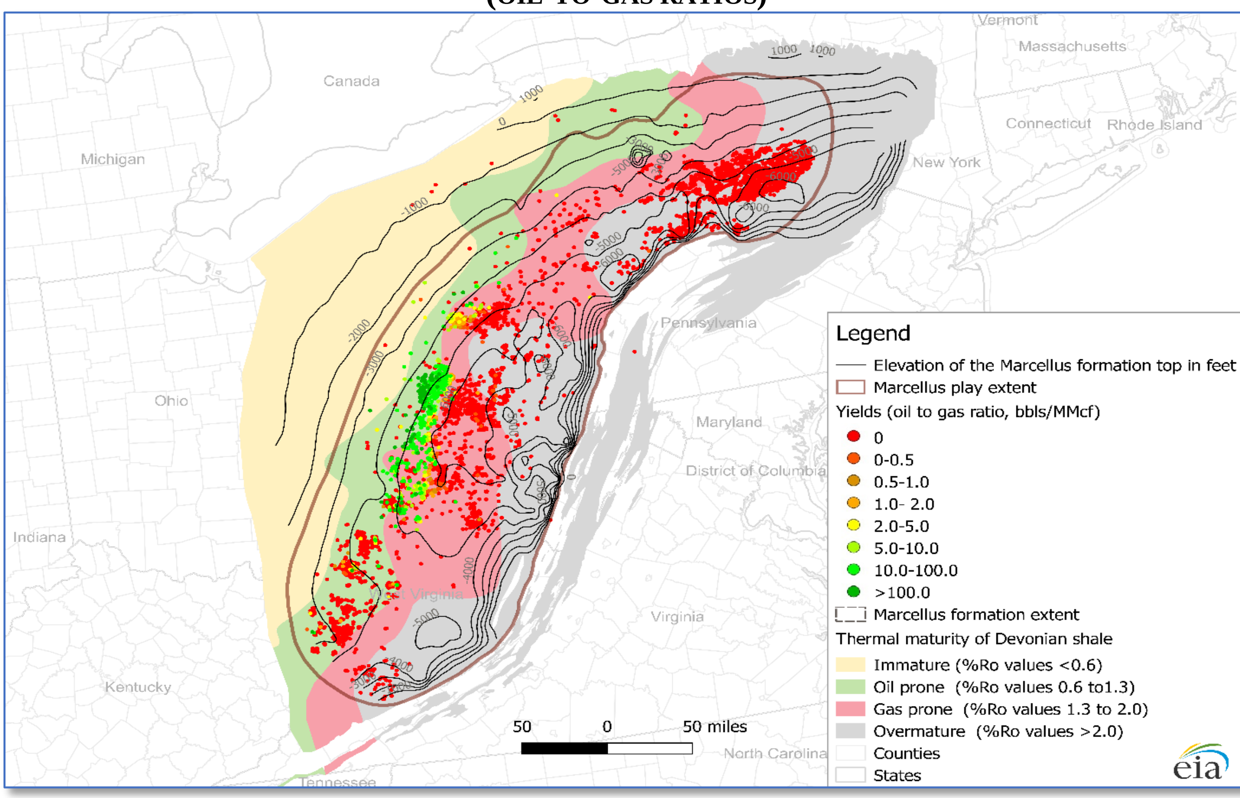
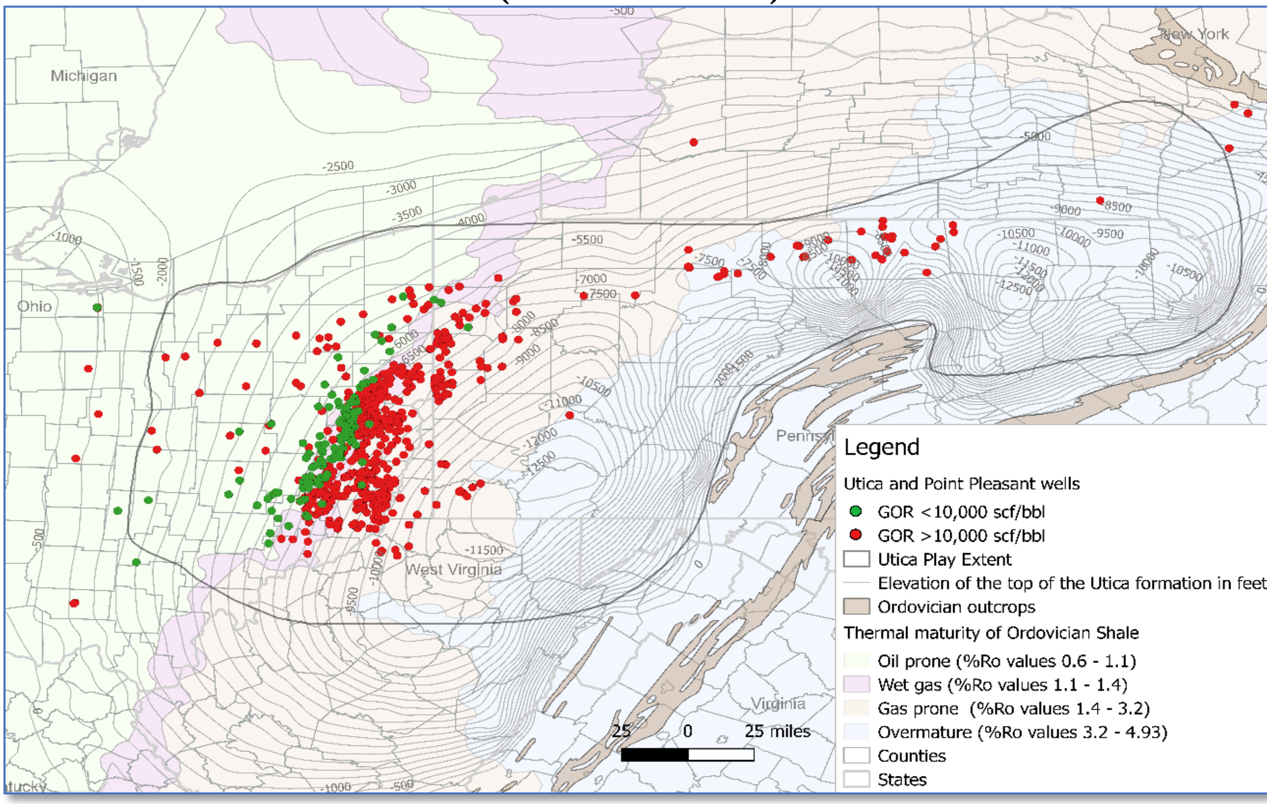


EXHIBIT 3: THERMAL MATURITY OF THE UTICA SHALE AND INITIAL YIELDS (GAS-TO-OIL RATIOS)



Considering this thermal maturation data coupled with the existing production wells in nearby counties to the DRB, an anticipated production area for the Marcellus and Utica shales within Pennsylvania and within the DRB has been developed. **Exhibit 4** depicts the anticipated production extent (APE) of both the Marcellus and Utica shales.

Based on this information, a geographical information system (GIS) analysis was conducted to identify the amount of land surface overlying the shale plays in each county within the DRB that is in Pennsylvania. This land surface amount represents the available surface area for likely development. The acreage identified in each county that is within the APE totals an estimated 1,113,681 acres or approximately 47.1% of the total acreage in the six counties of interest (Carbon, Lackawanna, Luzerne, Monroe, Pike, Wayne). A summary of the acreage quantities overlying shales in the counties of interest is shown in **Exhibit 5**.

EXHIBIT 4: ANTICIPATED PRODUCTION EXTENT OF MARCELLUS AND UTICA SHALE WITHIN PENNSYLVANIA

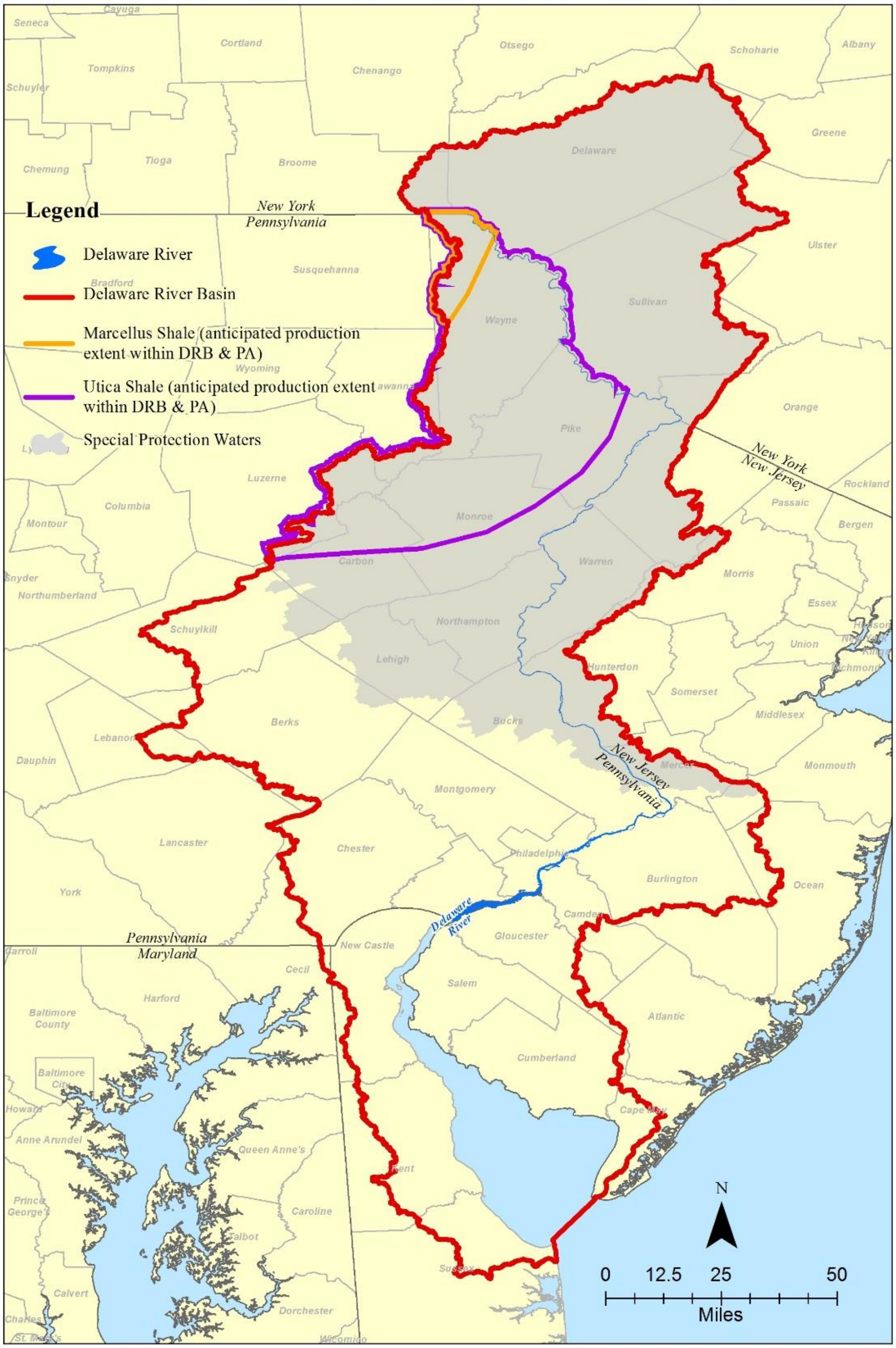


EXHIBIT 5: PERCENT OF COUNTY WITHIN ANTICIPATED PRODUCTION EXTENT (APE) IN DRB

County	~Total Acreage	~Acreage overlying Shale in APE of DRB	~Percent of County Overlying Shale in APE of DRB
Carbon	247,968.00	77,429.90	31.23%
Lackawanna	297,427.20	45,144.75	15.18%
Luzerne	580,364.80	83,317.72	14.36%
Monroe	395,116.80	218,137.96	55.21%
Pike	362,502.40	247,905.36	68.39%
Wayne	480,364.80	441,745.04*	91.96%
Total	2,363,744.00	1,113,680.73	47.12%

2.1.2 Available Surface

In order to analyze the impact of the proposed prohibition of HVHF, the available surface for shale development infrastructure within the DRB was estimated under the previous proposed (Article 7) regulations as proposed in 2010. These previously proposed regulations were applied to the APE boundary to identify the likely remaining acreage available for development under the latest anticipated development scenario and to demonstrate that the anticipated development could be conducted in a reasonable manner over a restricted area with minimal disturbance. ALL performed a GIS analysis of the APE area within the DRB that overlies the Marcellus and Utica shales. The surface acreage available for well pad placement, access roads, and utility rights-of-way (ROWs) was derived after siting restrictions, setbacks, and approval-by-rule criteria were applied as GIS layers. Note, this analysis should not be construed as an endorsement or agreement with the previously proposed Article 7 regulations, it is merely a case study using previously proposed and publicly commented on restrictions to determine if the anticipated gas development could be conducted with restrictions in place that are protective of the DRB versus the complete prohibition of any development, thus indicating that other options could be considered.

The analysis used representative polygons of the various Article 7 restrictions, setbacks, and Approval-by-Rule (ABR) criteria so that the areas in the APE of the Marcellus and Utica shales within the DRB could be queried and summary acreages for each criterion generated. The results of GIS analysis show that there are approximately 1,787 sq. miles of the DRB that overlay the APE of the Marcellus and Utica shales. Within the APE there are ~121 sq. miles of Flood Hazard Area (100-year flood plain), which would be restricted from development. An additional ~769 sq. miles would be restricted where a variance would be required for well pad placement due to slope or setback requirements. A remaining ~897 sq. miles would be available for well pad placement without a variance (approval for well pad placement would be either by docket or ABR with an approved Natural Gas Development Plan [NGDP]) (See **Exhibit 6**). The provisions of the ABR process without an approved NGDP would restrict ~725 square miles from well pad placement. A total of ~898 sq. miles would be available for well pad placement under the ABR process; however, ~697 sq. miles of that would be subject to forested site constraints, leaving only ~201 sq. miles for well pad placement without restrictions or constraints (see **Exhibit 7**). **Exhibit 8** provides a breakdown of the GIS layer analyses.

* The acreage overlying the shales in Wayne County is made up of approximately 371,707 acres, of which all of it is over the Utica, and an additional 70,038 acres over the Utica and Marcellus.

EXHIBIT 6: SITING RESTRICTIONS AND SETBACKS – NATURAL GAS DEVELOPMENT PLAN

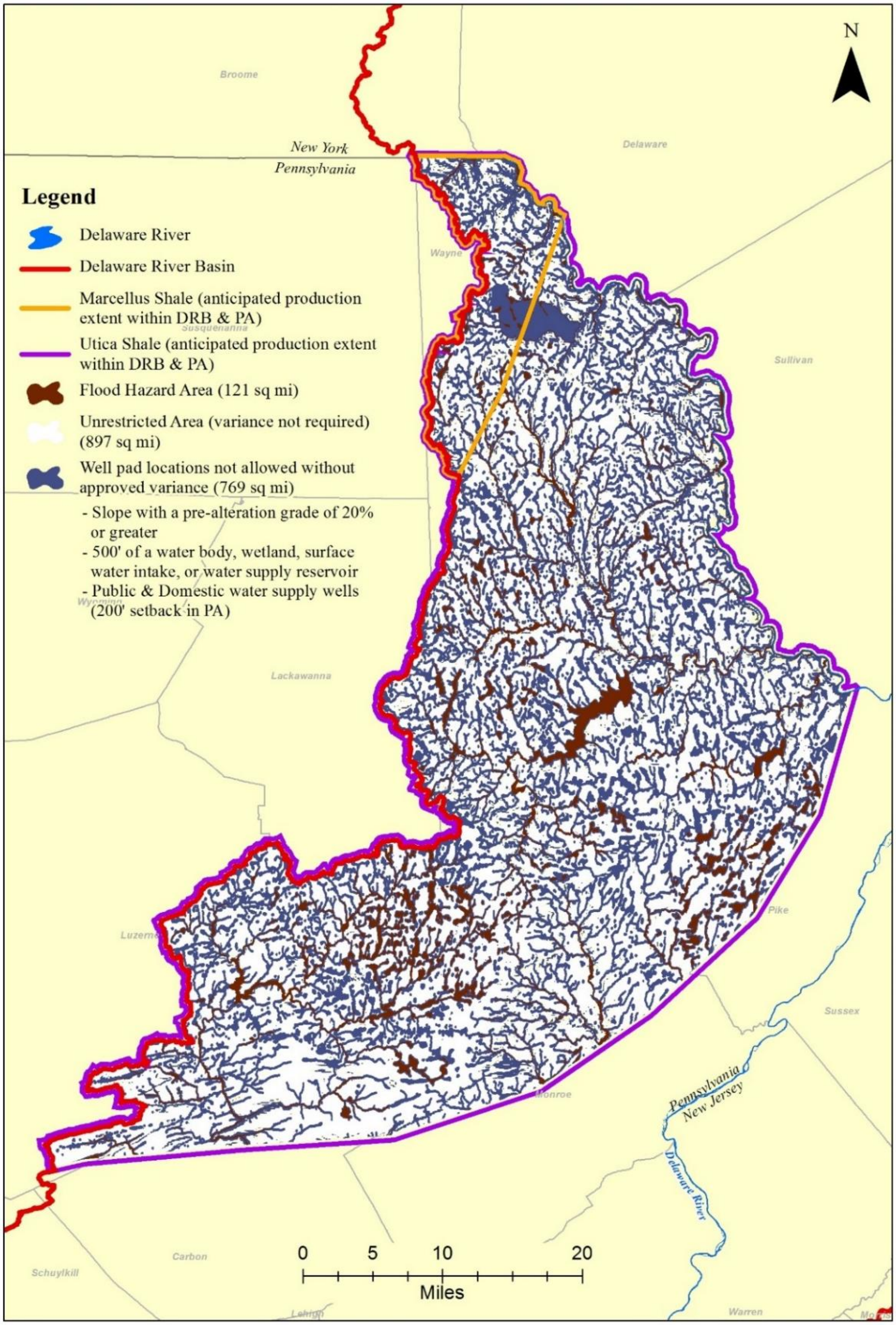


EXHIBIT 7: SITING RESTRICTIONS AND SETBACKS – APPROVAL BY RULE WITHOUT A NGDP

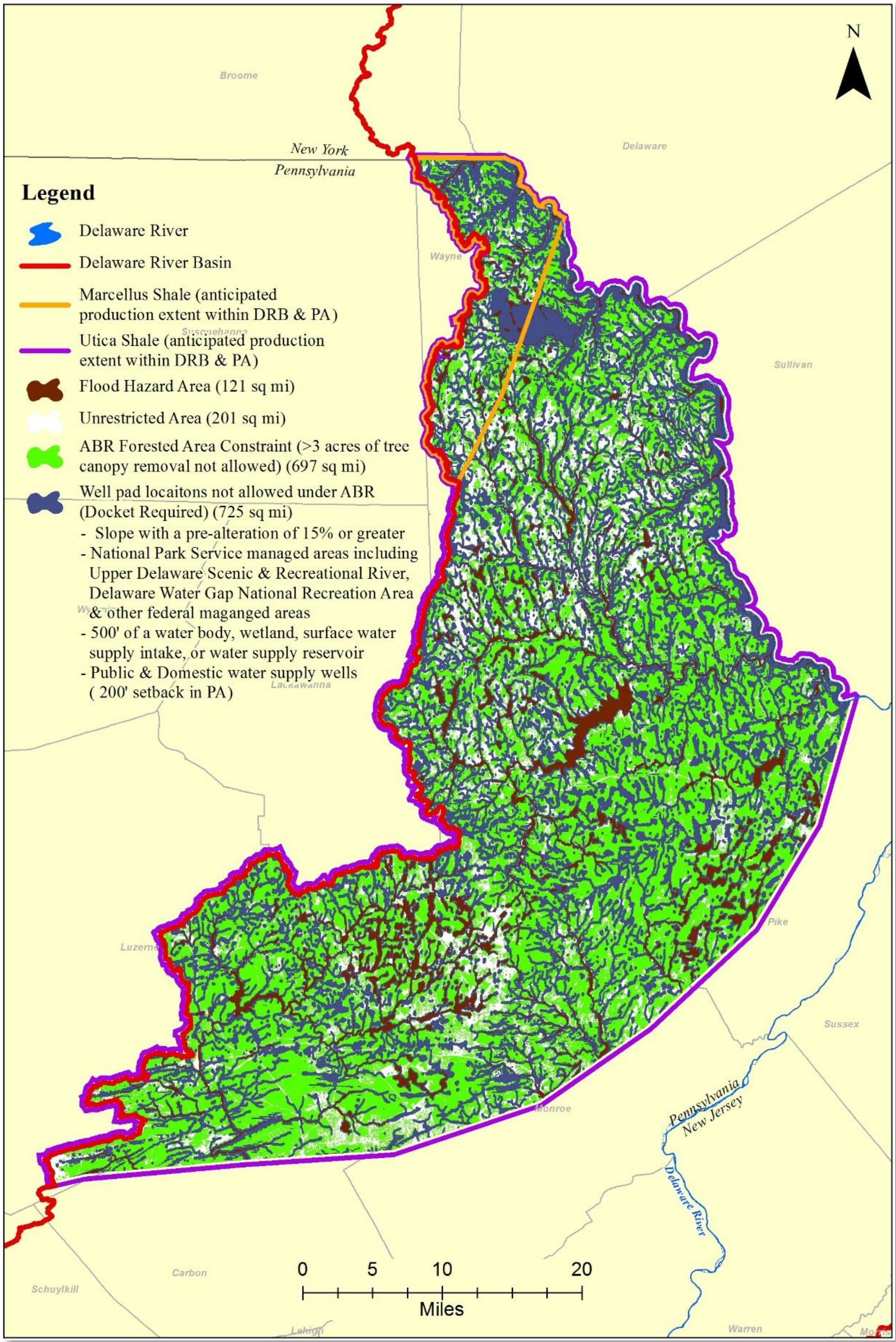


EXHIBIT 8: GIS LAYER ANALYSIS FOR ANTICIPATED PRODUCTION EXTENT WITHIN THE DRB

	GIS Layer Analysis Areas (ALL Quantities in Square Miles)	In APE of DRB Over Shale	% in APE of DRB Over Shale
1	Delaware River Basin Commission Area (13,611 miles^2)	1,787	100%
2	Special Protection Waters (Entire Area 6,878 miles2)	1,787	100%
3	Upper Delaware Scenic and Recreational River (Entire Area 59 miles^2)	25	1.40%
4	Southeastern Groundwater Protected Area (Entire Area 1,164 miles^2)	0	0
5	Delaware River Water Gap National Recreation Area (Entire Area 107 miles2)	0	0
	Restricted Areas		
6	Flood hazard Areas (100-year Floodplains)	121	6.77%
7	Slope Pre-alteration Grade 20% or Greater	95	5.32%
8	T&E Critical Habitat (Data not released by states, identify on project specific basis)	N/A	N/A
	Setbacks		
9	DRBC Water Body Setback (500')	700	39.17%
10	DRBC Wetlands Setback (500')	628	35.14%
11	Public and Domestic Water Supply Wells (200') (Number of wells PA -1,280)	3	0.17%
12	Surface Water Supply Intake (500')(Assumed included within 500' setback for streams & waterbodies)	N/A	N/A
13	Occupied Homes (Host State) No Data	No Data	No Data
14	Public Buildings (Host State)	No Data	No Data
	Approval by Rule Criteria		
15	Slope Greater than 15%	192	10.74%
16	Forested Areas	697	39.00%
17	Upper Delaware Scenic and Recreational River (UPDE)	25	1.40%
18	Delaware Water Gap National Recreational Area (DEWA)	0	0
19	Surface Area Affected by Restrictions and Setbacks	0	0
	Analysis		
20	No well pad locations allowed (Restricted Area - Flood Hazard Areas)	121	6.77%
21	Well Pad Locations Not Allowed Without Approved Variance (Slope >20% and all setbacks)	769	43.03%
22	Well Pad Locations Allowed With Docket Approval (Variance not Required)	725	40.57%
23	Well Pad Locations Allowed Under ABR With Approval But Subject to Forest Site Constraints (>3 acres)	697	39.00%
24	Well Pad Locations Allowed Under ABR With Approval Not Subject to Forest Site Constraints	201	11.25%
	Notes: APE - Anticipated Production Extent		

2.1.3 Oil & Gas Development Forecast

The principal aspects motivating oil and gas exploration and development are supply and demand, energy commodity prices, technological innovations, and environmental impact potential. Deviations in any of these influences such as the recent slight rise in crude oil and natural gas prices[10,11] or the development of new horizontal drilling and hydraulic fracturing technology[12,13] can significantly alter economic parameters and influence decision making.

2.1.3.1 Natural Gas Resources in Appalachia

The EIA estimates considerable development in natural gas and natural gas liquids (NGL) production in Appalachia over the coming decades. Natural gas production from the Marcellus/Utica region increased from 2.0 billion cubic feet per day (Bcf/d) in January 2010 to 24.2 Bcf/d in August 2017; this represents approximately one-third of all U.S. dry natural gas production. Natural gas production in the Appalachian region is projected to continue very steady growth in the near and long term. Natural gas output is expected to be 8 trillion cubic feet (Tcf) in 2017 and estimated to increase 60% by 2020. Output in 2050 is projected at 18.7 Tcf.[14]

2.1.3.2 Methodology for Estimating Future Oil and Gas Exploration and Development Activity

To estimate the future oil and gas exploration and development activities that can reasonably be expected to occur in the DRB over the next 10 years, an analysis of the Pennsylvania drilling permits issued and wells drilled between 2013 and 2017 by county and proximity to the DRB was conducted. Ten years was chosen as a practical duration for the current analysis. This forecast is based on the area's geology and historical and present activity, as well as factors such as economics, technological advances, access to oil and gas areas, transportation, and processing facilities. Projections of oil and gas activities are based upon present knowledge. Future changes in global oil and gas markets, infrastructure and transportation, or technological advancements may affect future oil and gas exploration and development activities within the state.

Estimated oil and gas activity does not necessarily correlate with geologic potential for the presence of hydrocarbons. Although the geology of an area may suggest the possibility of oil and gas resources, actual exploration and development may be restricted by high exploration costs, low oil and gas prices, or difficulty accessing the area due to lease stipulations or regulations. Thus a small area may have a high resource potential, yet have a low exploration and development potential due to severe restrictions on access. Conversely, technological advancements or an increase in oil and gas prices could result in oil and gas activities in areas regarded as having less or moderate potential for occurrence

2.1.3.3 Pennsylvania Well Permits Issued and Wells Drilled

A review of the Pennsylvania Department of Environmental Protection's (PA DEP) online Oil and Gas Reports reveals the number of permits issued for unconventional wells, as well as the number of unconventional wells drilled by county. Information regarding the permits issued for unconventional wells by county were obtained for years 2013-2017 using the PA DEP *Interactive Reports – Permits Issued Detail Report / Year to Date-Permits Issued by County and Well Type Report*. An analysis of the four producing counties (Bradford, Sullivan, Susquehanna, Wyoming) nearest the DRB anticipated production area indicates that the rate of permits issued has generally declined from 2013 to 2016 with a slight increase in 2017 for Bradford and Sullivan Counties. This information is depicted in **Exhibit 9**.[15]

Information regarding the unconventional wells drilled by county was also obtained for years 2013-2017 using the PA DEP *Interactive Reports – SPUD Data Report / Wells Drilled By County*. An analysis of the same four nearby producing counties indicates that the rate of drilling followed a similar decline trend between 2013 and 2016 followed by a slight increase in 2017 for all four counties. This information is depicted in **Exhibit 10**.[16]

The Bureau of Land Management (BLM) Reasonable Foreseeable Development Scenario (RFDS) for Fluid Minerals in Pennsylvania, prepared in September 2011, was also evaluated for any insights with regards to development estimations.[17]

Exhibit 9: Unconventional Well Permits Issued in Counties near the DRB (2013-2017)

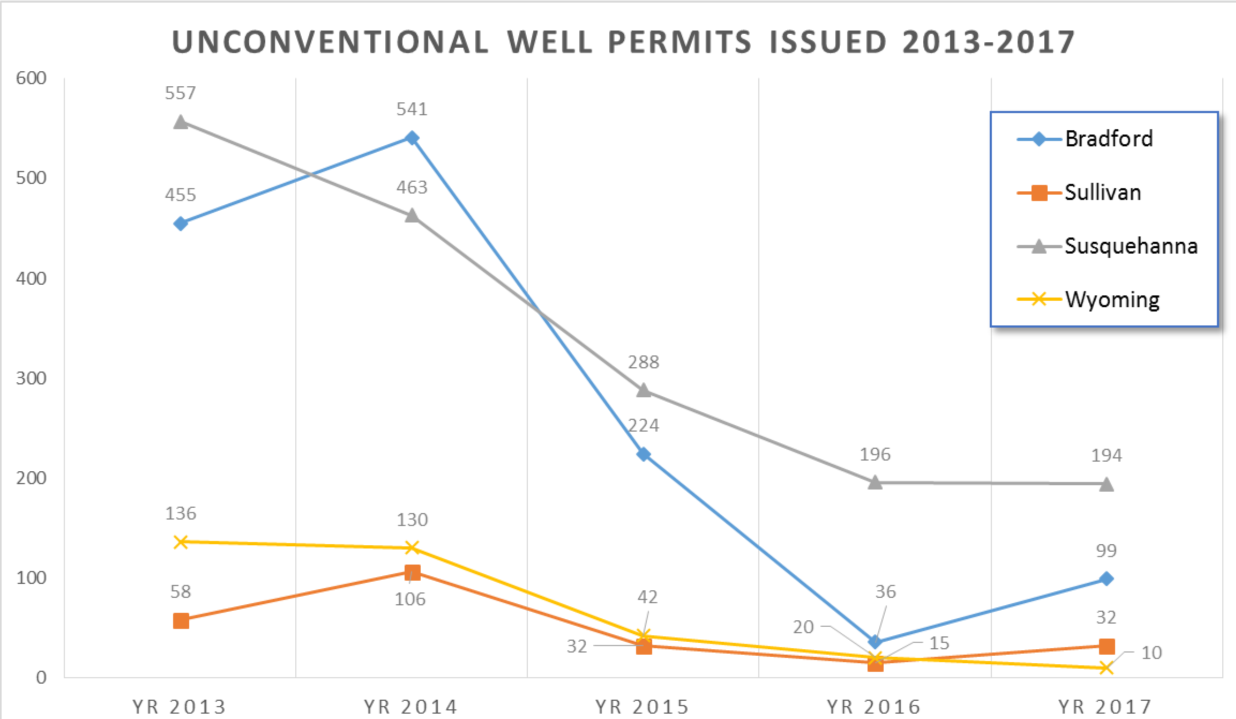
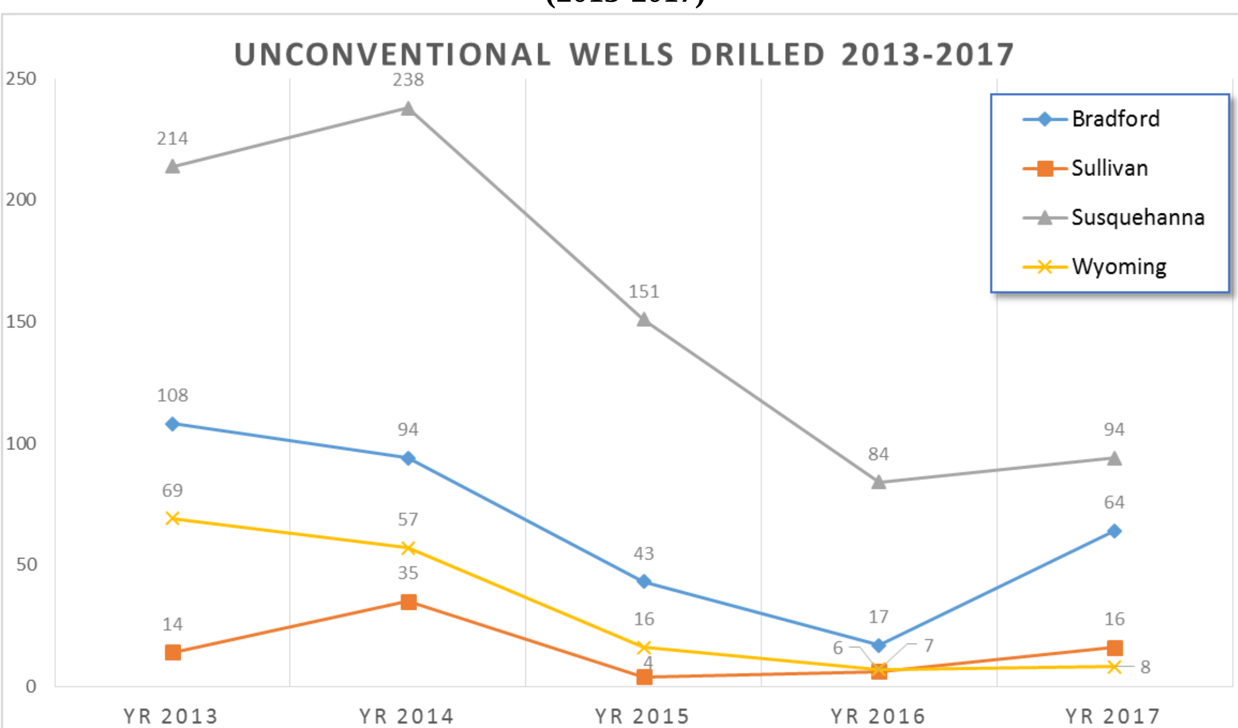
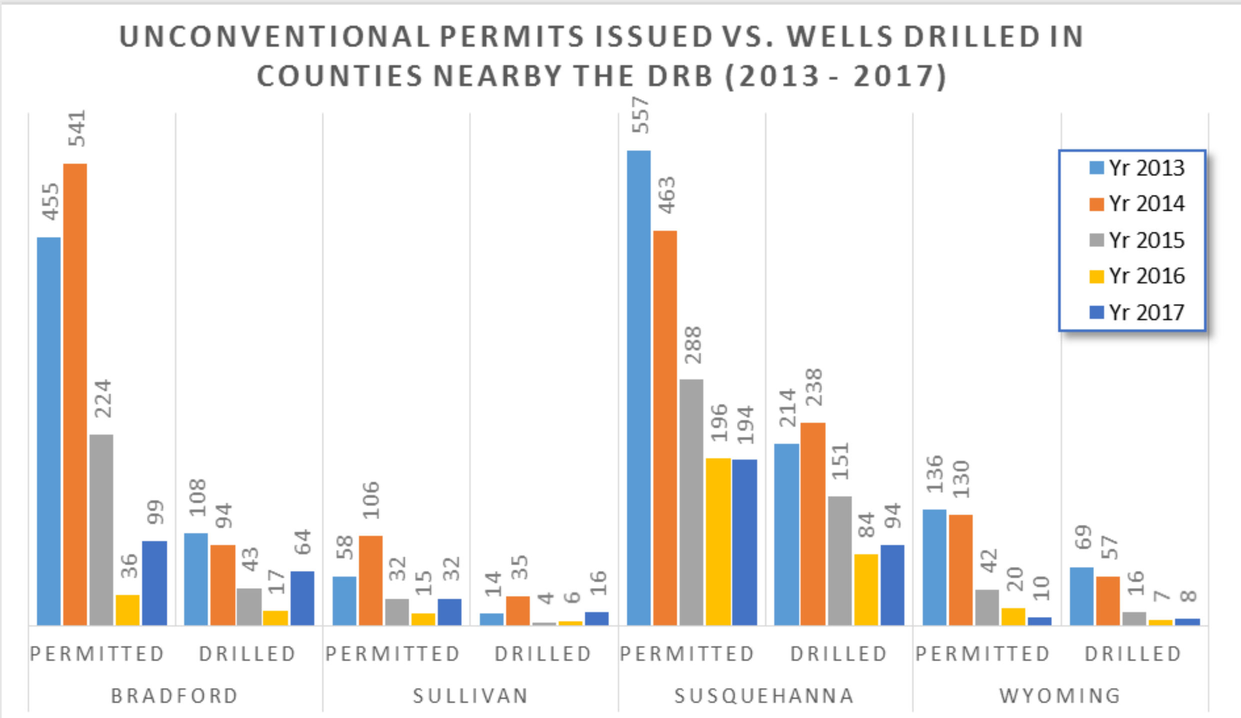


Exhibit 10: Unconventional Wells Drilled in Counties Nearby the DRB (2013-2017)



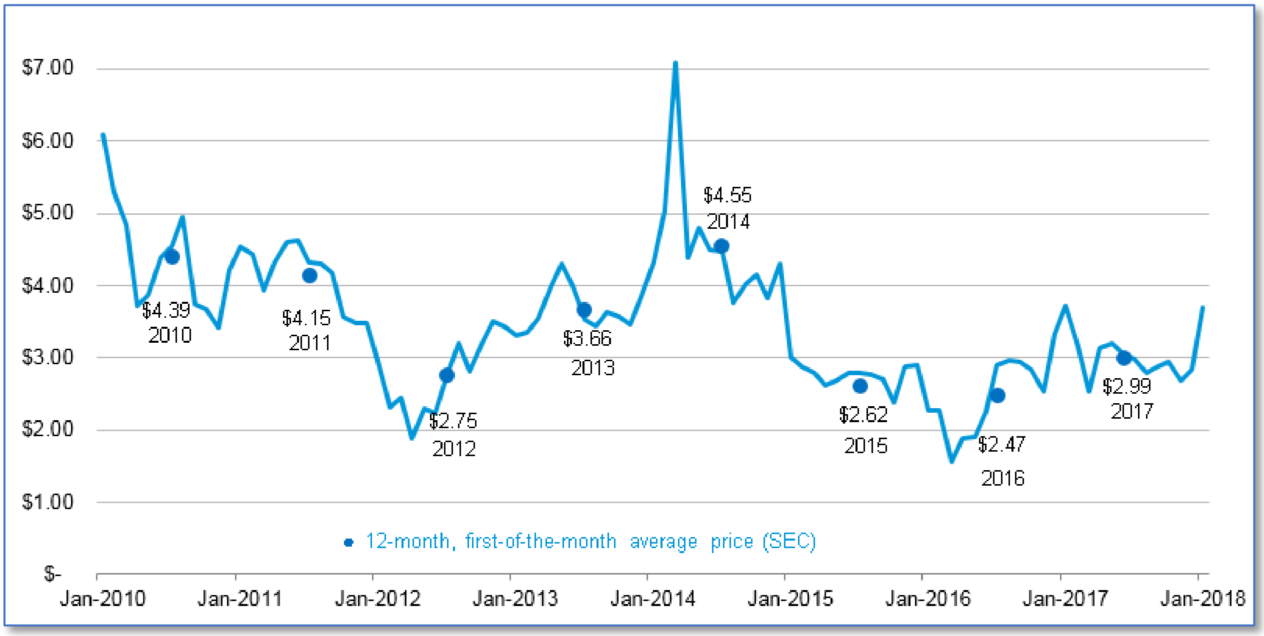
A comparison of the unconventional permits issued versus the unconventional wells drilled in these four nearby counties exposes the fact that generally less than half of the permits issued each year results in a well being drilled. This ratio reflects the numerous factors influencing drilling activity in Pennsylvania including price and demand fluctuations, drill rig availability, and pipeline capacity. **Exhibit 11** provides a side-by-side bar graph of the permits issued versus the wells drilled by nearby county.

EXHIBIT 11: UNCONVENTIONAL WELL PERMITS ISSUED VS. WELLS DRILLED IN COUNTIES NEAR THE DRB (2013-2017)



The BLM RFDS provided estimations for the federal minerals within the State on a county basis using data from 2003 to 2010 and addressed the earlier history of natural gas development in the Appalachian Basin with regard to natural gas prices. Of interest was the industry's reaction to the price changes in 2008. It was a jump in natural gas prices that began in 2003 that helped stimulate interest in the Appalachian Basin. Exploration and development activities increased at a swift pace as the average monthly price rose to a high of $12.69 per thousand cubic feet (Mcf) in June of 2008. By September 2009 the price for natural gas had dropped to $2.99 per Mcf.[18] The decline in the natural gas price slowed the exploration and development pace of the Marcellus and Utica shales but it did not eliminate the interest in development. The following period of somewhat steady pricing (2010-2017, ~$3.42 +/- $1.20) has provided good data for evaluation with regard to development growth under tight economic conditions. During this period, operators developed and implemented additional cost-saving technology for drilling and production. See **Exhibit 12** for Henry Hub natural gas spot prices from 2010-2017.[19]

EXHIBIT 12: HENRY HUB NATURAL GAS SPOT PRICE (FIRST-DAY-OF-THE-MONTH) 2010-2017



The EIA appraises the proven natural gas reserves in the Marcellus Play at 77.2 Tcf as of the end of 2015.[20] The EIA has not estimated the proven natural gas reserves for the Utica shale in Pennsylvania seperately but recognizes the potential for dry gas in the area of the DRB. The now-proven recoverable reserves and the improved economic margins for the production of natural gas from the Marcellus and Utica shales should add to a solid foundation of cost control resulting in continued moderate growth of the Marcellus and Utica shales throughout the next 10-year period.

2.1.3.4 Oil and Gas Development Potential in the DRB

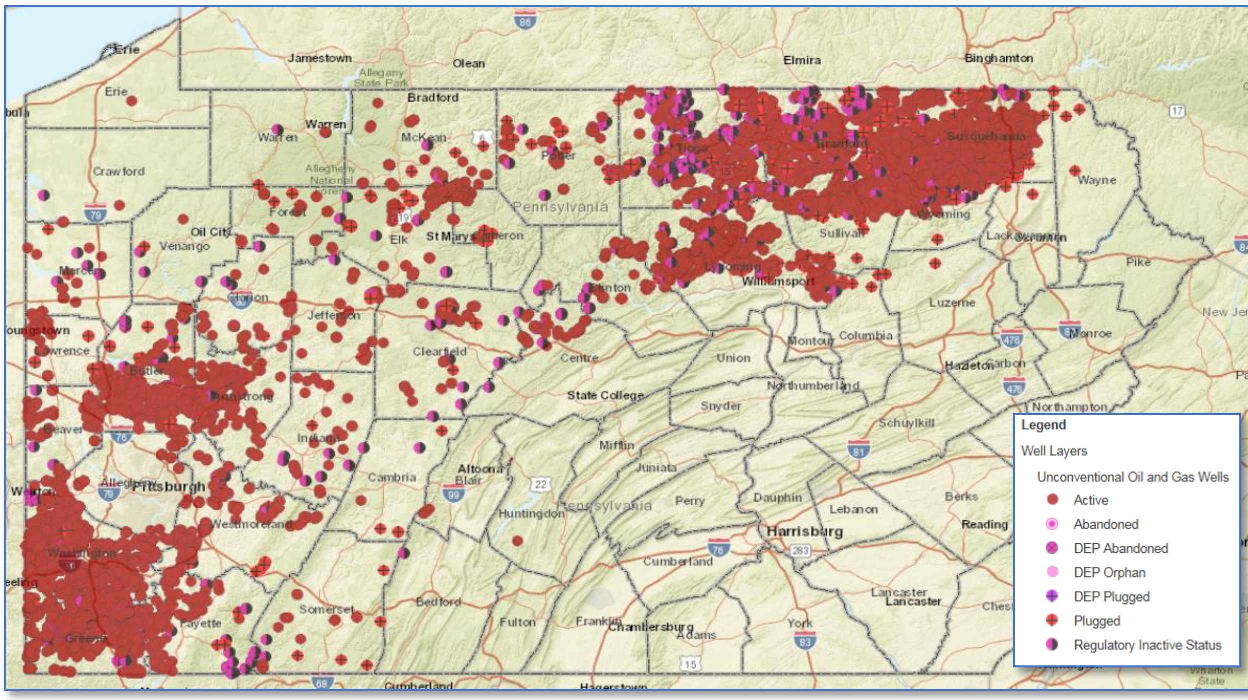
Since the first Marcellus gas wells were drilled in Pennsylvania in 2003, the state has seen relatively steady growth in exploration and production activity that is expected to continue for the foreseeable future. Given the information reviewed, each of the six counties in the DRB within Pennsylvania was assessed according to its individual potential for oil and gas development over the next 10 years. The data for each county were analyzed in relation to the county's relative position within the existing oil and gas regions of the state. Each county was assigned a value for potential oil and gas development and classified as having either High, Medium, or Low developmental potential over the next 10 years. This information coupled with the type of potential hydrocarbon present, the presence of potential productive formations, formation depths, thickness, thermal maturity, and other information provided previously in this report, was used as a basis for projecting the potential for oil and gas development. **Exhibit 13** presents the rankings according to the projected production potential and the forecast for annual wells. The low rankings for development potential reflect the thermal maturation of the shales in the eastern portion of the state and the lack of past activity as depicted in **Exhibit 14**. **Exhibit 14** is a map of the unconventional wells drilled into the Marcellus and Utica shales in Pennsylvania.[21] The PA DEP map shows few wells drilled in the counties of interest and seems to indicate a decline in operator activity from west to east in Susquehanna County, as well as a decline from north to south in Wyoming County.

As shown in the table, this analysis estimates a development potential of 40 wells drilled each year for the next ten years.

EXHIBIT 13: HVHF WELL FORECAST FOR PENNSYLVANIA COUNTIES WITHIN THE DRB OVERLYING SHALES

County	Type	Development Potential	Forecast Annual # of Wells	
			Gas Wells	Oil Wells
Carbon	Gas	Low	5.0	0.0
Lackawanna	Gas	Low	5.0	0.0
Luzerne	Gas	Low	5.0	0.0
Monroe	Gas	Low	5.0	0.0
Pike	Gas	Low	5.0	0.0
Wayne	Gas	Low	15.0	0.0
		Total	40.0	0.0

EXHIBIT 14: UNCONVENTIONAL WELLS DRILLED IN PENNSYLVANIA



2.2 Water

2.2.1 Water Resources

The Water Resources Operations staff of the DRBC prepares annual Hydrologic Conditions in the Delaware River Basin reports.[22] A review of the latest report available (2016) indicates the following hydrologic highlights:

- The majority of the DRB counties saw below-normal precipitation during 2016. Only four southern counties out of the 38 total chronicled above-normal precipitation for the year. Annual precipitation in the anticipated production extent counties of interest were approximately 25% below normal as follows: Carbon -8.4", Lackawanna -8.4", Luzerne -8.0", Monroe -12.1", Pike -9.5", and Wayne -6.5".

- The mean streamflows along the main stem of the Delaware River and its two largest tributaries, the Lehigh and Schuylkill rivers, were normal to above normal from January through August; however, in September average monthly flows were generally below normal and remained that way for the remainder of 2016.
- The lower basin reservoir storage required releases totaling 9 billion gallons (Bgals) during 2016 to meet minimum flow objectives and to deter salinity in the Delaware Estuary. Late in the year (October/ November) the storage reservoirs were down and the drought warning was close to going into effect; however, before this happened, DRBC affirmed a basin-wide drought watch on November 23, 2016. Precipitation in late November and December increased storage volumes and the normal winter pool elevations were eventually reached and additional releases from this reservoir were no longer required through the end of 2016.
- The upper basin contains the three NYC Delaware reservoirs. These reservoirs are operated on a flexible flow management program. In the beginning of the year their combined storage was 2146 Bgals, which was 11 Bgals below the long-term median usable storage for that period. Precipitation raised the storage volume above the long-term median by early May, which was slightly (10 days) later than the normal refill date. Storage volumes severely dropped over the summer and fall months until in late November when the combined storage fell below the drought watch operation curve motivating the DRBC to issue the basin-wide drought watch. Again, late-year precipitation increased combined storage above the drought watch threshold, but not high enough to end the basin-wide drought watch. On New Year's Eve the reservoirs held 135.7 Bgals, just over half of their useable capacity but still 89 Bgals below the long-term median volume.
- Pennsylvania groundwater monitoring included measurements from Wayne County, which indicated that levels were generally within the normal range (25th to 75th percentile) for the first half of the year, although levels declined to below normal during the drier periods of April and May. By late May the trend was downward and by November levels were below the normal range. Again, increased precipitation during December caused the Wayne County water level to markedly increase to within the normal range by the end of the year.

A review of the previous three years of Hydrologic Conditions in the DRB reports (2013-2015) indicate a similar below-normal annual precipitation in the Upper Region with periodic reservoir releases conducted to augment late year streamflow lows and groundwater levels experiencing fluctuations below the 25th percentile for portions of the year. Reasons for the reduced precipitation are not discussed.

2.2.2 Water Use

Water use in the DRB was evaluated using the data provided in the U.S. Geological Survey (USGS) "Estimated Use of Water in the United States in 2010,"[23] as downloaded for Pennsylvania and filtered by county for the DRB. The USGS National Water-Use Science Project compiles and disseminates the nation's water-use data every five years. The USGS works with local, State, and Federal environmental agencies to collect water-use data at the county level. USGS compiles data by domestic, industrial, irrigation, livestock, aquaculture, mining, and thermoelectric power generation. The USGS 2010 data is the latest data available in its entirety as the 2015 data has not been released yet. The USGS data findings were compared to the DRBC's *Draft Water Resources Program FT 2017-2019* Report for water use in the Upper Region.

Water withdrawal amounts as reported by the USGS in Million gallons per day (Mgal/d) were analyzed for the six counties of interest in the Upper Region of the DRB with anticipate shale production. The daily withdrawal amounts for the following groundwater and surface-water Use Sectors were totaled per county to provide a total daily withdrawal amount.

- Public Supply
- Domestic, self-supplied
- Industrial, self-supplied
- Irrigation-Crop
- Irrigation-Golf
- Livestock
- Aquaculture
- Mining
- Thermoelectric

The data indicated that a total of 205.86 Mgal/d are being withdrawn from these six counties. The top three use sectors account for approximately 91.5% of total daily water withdrawals; these sectors are public supply (53.6%), thermoelectric (28.4%), and domestic self-supplied (9.6%). Also, two dominant counties account for ~66.7% of the total daily water withdrawals; these are Luzerne (41.4%) and Lackawanna (25.3%) Counties. However, when the percentage of the anticipated shale production extent per county (see **Exhibit 5**) within the DRB is applied to the total withdrawal quantities per county the total daily withdrawal is adjusted to 54.68 Mgal/d. The two dominant counties also changed when the anticipated production extent percentages were applied; these are Monroe (33.4%) and Luzerne (22.4%). **Exhibits 15**, **16**, and **17** show the sum of these water withdrawals by use sector and county totaled and with percentages of county within the anticipate production extent applied.

EXHIBIT 15: USGS REPORTED WATER WITHDRAWALS BY USE SECTOR WITHIN DRB COUNTIES OF INTEREST

Total Water Withdrawals	Carbon County	Lackawanna County	Luzerne County	Monroe County	Pike County	Wayne County	Total
Sum of Public Supply, total groundwater withdrawals	2.88	1.76	4.28	6.24	2.83	2.51	20.5
Sum of Public Supply, total surface-water withdrawals	20	45.51	17.09	7.15	0	0	89.75
Sum of Domestic, self-supplied groundwater withdrawals, fresh	1.4	4.14	5.83	5.54	0.89	1.91	19.71
Sum of Domestic, self-supplied surface-water withdrawals, fresh	0	0	0	0	0	0	0
Sum of Industrial, total self-supplied groundwater withdrawals	0.07	0	0.02	0	0	0	0.09
Sum of Industrial, total self-supplied surface-water withdrawals	0	0	0	0.34	0	0	0.34
Sum of Irrigation-Crop, groundwater withdrawals, fresh	0.02	0.03	0.04	0.01	0	0.02	0.12
Sum of Irrigation-Crop, surface-water withdrawals, fresh	0.06	0.09	0.15	0.03	0.01	0.08	0.42
Sum of Irrigation-Golf, groundwater withdrawals, fresh	0.05	0	0	0.12	0	0	0.17
Sum of Irrigation-Golf, surface-water withdrawals, fresh	0.04	0	0	0.14	0.04	0	0.22
Sum of Livestock, groundwater withdrawals, fresh	0.02	0.08	0.1	0.02	0.01	0.29	0.52
Sum of Livestock, surface-water withdrawals, fresh	0.01	0.01	0.02	0.01	0	0.04	0.09
Sum of Aquaculture, total groundwater withdrawals	0.16	0	0	1.06	0.45	0.17	1.84
Sum of Aquaculture, total surface-water withdrawals	0.04	0	0	12.33	0.3	0.72	13.39
Sum of Mining, total groundwater withdrawals	0	0.15	0.02	0.07	0.02	0.05	0.31
Sum of Mining, total surface-water withdrawals	0	0	0	0	0	0	0
Sum of Thermoelectric, total groundwater withdrawals	0.35	0	0	0	0	0	0.35
Sum of Thermoelectric, total surface-water withdrawals	0	0.29	57.75	0	0	0	58.04
Total Water Usage Daily Mgal/day	**25.1**	**52.06**	**85.3**	**33.06**	**4.55**	**5.79**	**205.86**
Percentage of County within APE	*31.23%*	*15.18%*	*14.36%*	*55.21%*	*68.39%*	*91.96%*	
Water Withdrawn Based on % of County within APE	*7.84*	*7.90*	*12.25*	*18.25*	*3.11*	*5.32*	*54.68*
Percent of Total Withdrawn	**12.2%**	**25.3%**	**41.4%**	**16.1%**	**2.2%**	**2.8%**	
Percent Withdrawn within APE	14.3%	14.5%	22.4%	33.4%	5.7%	9.7%	

EXHIBIT 16: USGS REPORTED WATER WITHDRAWALS BY DRB COUNTY TOTAL VS. PERCENT WITHIN ANTICIPATED PRODUCTION EXTENT

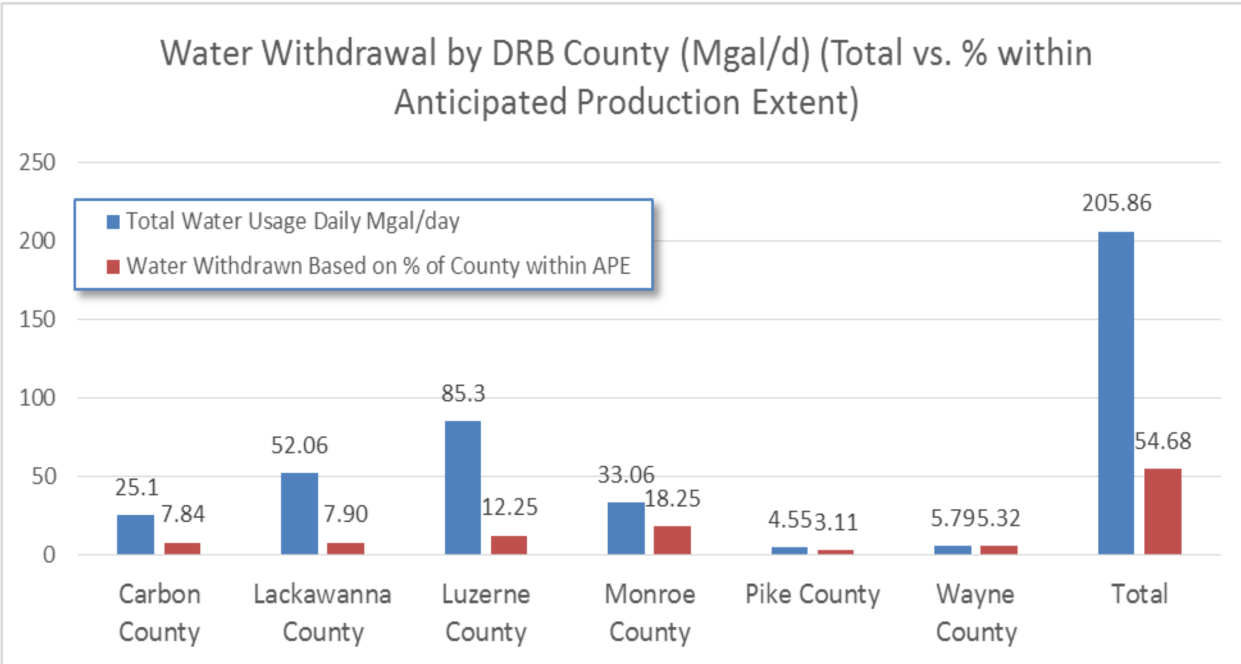
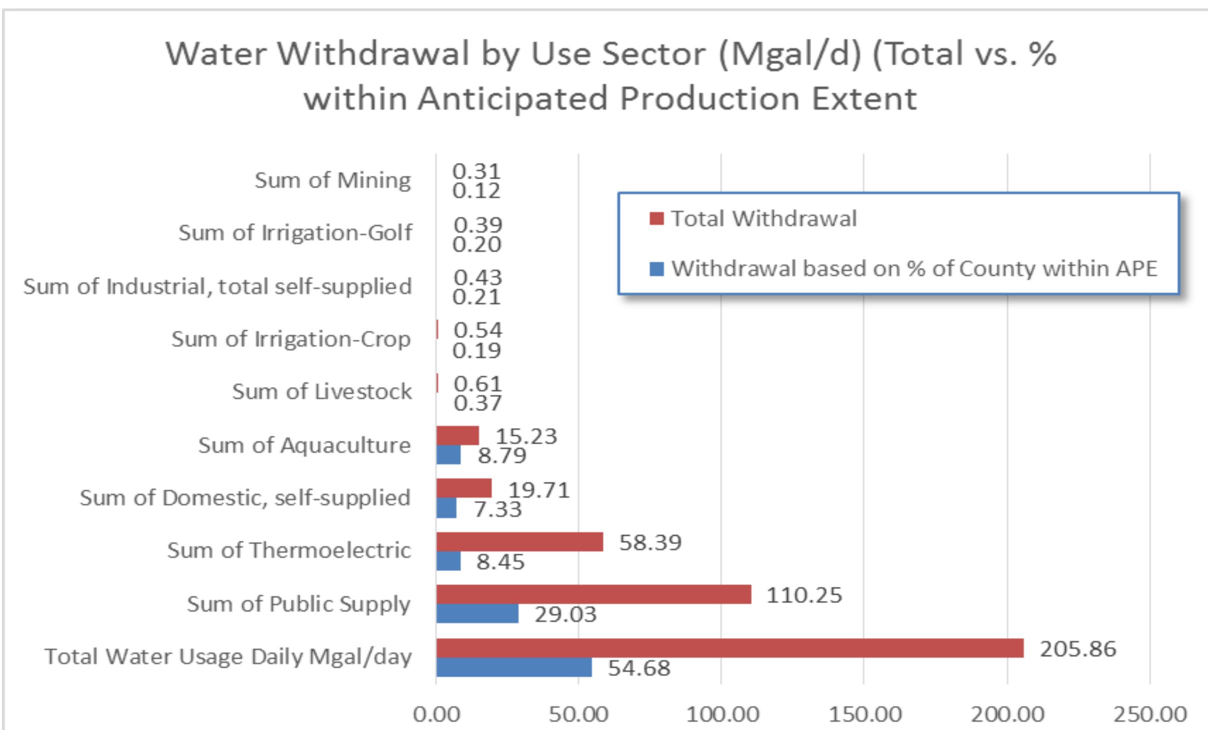
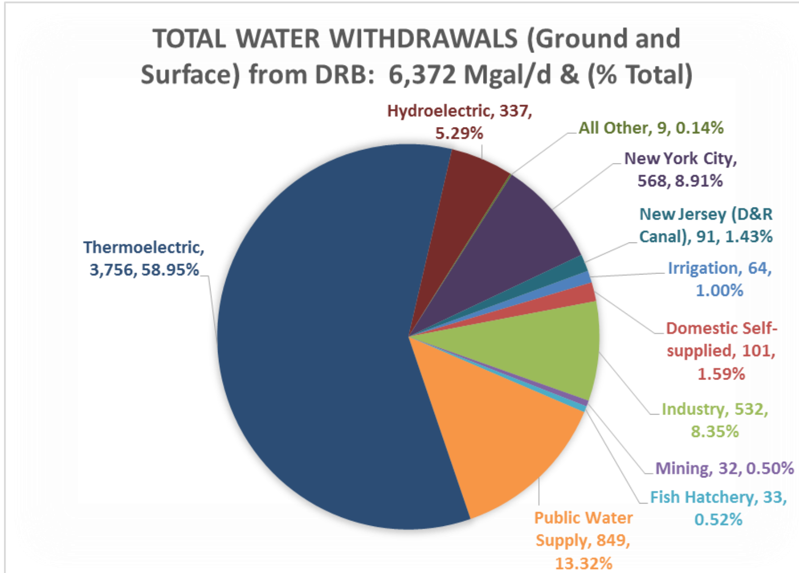


EXHIBIT 17: USGS REPORTED WATER WITHDRAWALS BY USE SECTOR TOTAL VS. PERCENT WITHIN ANTICIPATED PRODUCTION EXTENT



The USGS data reveals that all water withdrawals within the anticipated production extent of the counties of interest in the DRB currently totals 54.68 Mgal/d or approximately 19.97 Billion gallons annually. The DRBC tracks withdrawal and water use by similar use sectors and reports 6,372 Mgal/d withdrawn for the entire DRB.[24] **Exhibit 18** shows the DRBC use sectors and reported withdrawals based on 2014 data.

EXHIBIT 18: TOTAL WATER WITHDRAWALS REPORTED BY DRBC



The DRBC defines water not returned to the surface waters of the basin as consumptive use and as mentioned in their Additional Clarifying Amendments for the proposed rules they consider "most water used for HVHF is used "consumptively," meaning it is not returned to the basin's usable ground or surface waters."[25] This does not take into account the "new" water produced from shales and the amount of produced water that is recycled and reused. Annual corporate sustainability reports routinely identify the large percentages or volumes of water being recycled / reused, e.g., Apache reuses nearly 50% of their produced water,[26] Hess Corporation has a track record of increasing their reuse percentage annually over the past four years,[27] and Chesapeake Energy recycled over 94 Mgals in 2016.[28] **Exhibit 19** (extracted from the DRBC Draft Water Resources Program, FY 2017 – 2019 [figure 8]) depicts the range of withdrawals by DRBC region and shows the consumptive use as a percentage of total withdrawals (excluding exports to NYC and

EXHIBIT 19: DRBC REPORTED CONSUMPTIVE USE BY REGION

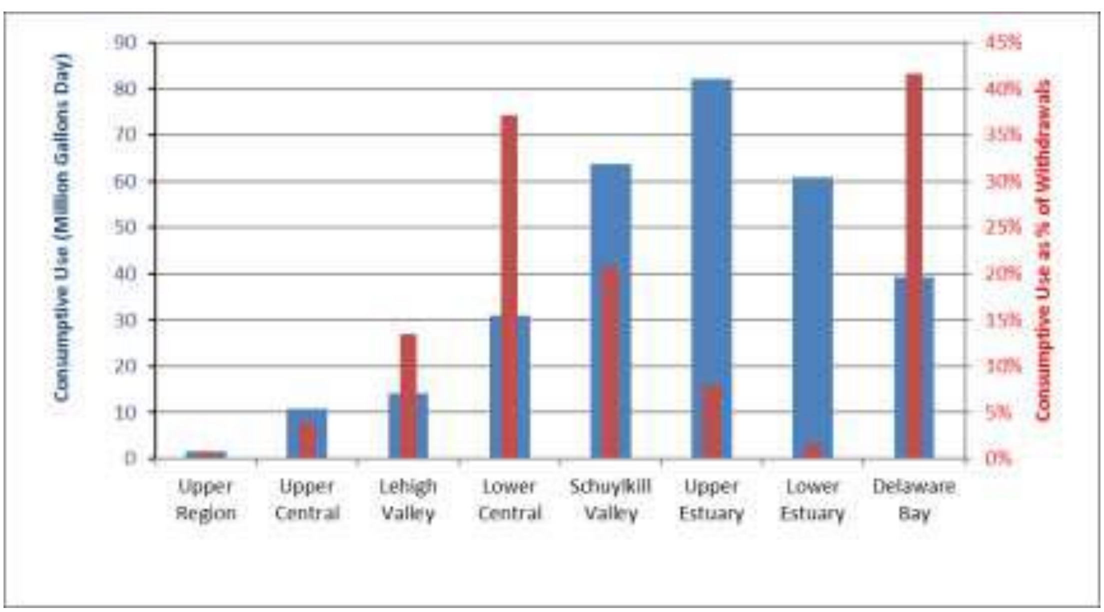


EXHIBIT 20: MAP OF DRBC REGIONS

NJ). The anticipated production extent area is in the Upper Region as depicted on **Exhibit 20** (figure 9) also obtained from the DRBC Draft Water program document. Note, the image, although grainy, appears to indicate that the Upper Region withdrawals about 1.5 Mgal/d for consumptive use and that represents an estimated 1.0% of the withdrawals. Based on this data the daily withdrawal in the Upper Region would be approximately 150 Mgals/d. This is considerably larger than the amount withdrawn from the anticipated production extent based on USGS data for the counties of interest (54.86 Mgal/d). The DRBC reports an estimated 559 Mgal/d is consumed as authorized and another 171 Mgal/d are lost or consumed as a total based on 2014 DRBC water audit program. This 730 Mgal/d consumed or lost represents ~11.5% of the daily withdrawals.

2.2.3 Water Availability

Water is the major component needed for removing natural gas from underground shale rock formations. Pennsylvania's precipitation totals and surface and groundwater resources are considerably larger than those of most southwestern and northern plain states where other shale fields are in mature gas production.

While water is bountiful in Pennsylvania, a variety of use sectors place significant demands on the water resources in the Upper Region of the DRB. The total withdrawal of ground- and surface water in the anticipated production extent of the

DRB approaches 55 Mgals/d. Anticipated drilling and fracturing supply water may come from streams, ponds, lakes, rivers, and groundwater withdrawals, as well as from treated wastewater, acidic mine drainage, recycled production water, or spent process/cooling water from other nearby industries. Generally, water withdrawals exceeding 10,000 gallons per day (gals/d) for any rolling thirty-day period require registration with the PA DEP under authority of Act 220 of 2002, the Water Resources Planning Act, and implementing regulations at 25 Pa. Code Chapter 110.

Irrespective of the basin from which water is withdrawn, PA DEP requires an approved water management plan coupled with a well permit to cover the water volumes used for fracturing. A water management plan includes information about the sources of water to be used in the HVHF process, potential impacts of withdrawals on water resources, and proof of approval by the appropriate river basin commission, among other items.[29]

The DRBC has expressed concern about large-scale water withdrawals from small, remote, forested streams, often home to wild trout and other sensitive species, that can be very susceptible to damage from withdrawals. Withdrawals from small forested streams need to be carefully planned to minimize the possible ecological consequences.

Water-use plans can be designed to allow operators to continuously withdraw water from a stream in a small quantity that has minimal impact on stream flows, such as a quantity that cumulatively would not exceed about 10% of Q7-10* low flows (called an uninterrupted withdrawal). Operators can also chose to withdraw larger amounts during times of high flow, usually in January and February in the Upper Region of the DRB, and store that water for use throughout the year. The Susquehanna River Basin Commission (SRBC) has granted some "passby flow determinations with interrupted withdrawal" that allow water withdrawal from smaller streams with the condition that withdrawal stop or decrease to a previously designated level when flows reach a preset minimum.[30]

Operators have also purchased water from municipal water systems and other permitted users. Within the Susquehanna River Basin (SRB) operators can purchase water, up to the total permitted amount, from users who have excess water. These sources may be used as long as they are registered under the applicable ABR for each drilling pad at which such sources would be used.[31] Water can also be withdrawn from private surface impoundments, provided operators have permission to access the water body, for which some landowners are charging an access fee. Withdrawals of water from ponds or lakes more than one acre in size may require additional approvals, such as a drawdown permit from the Pennsylvania Fish and Boat Commission.[32]

For purchases of water from a Public Water Supply Agencies (PWSA), the PA DEP considers the capability of the PWSA to sell water to the operator without threatening its ability to deliver drinking water to the public. In addition, the PA DEP considers the PWSA's own compliance with applicable laws, such as the Safe Drinking Water Act, the Water Rights Act and the Water Resources Planning Act.

* A 7-day low flow for a stream is the average flow measured during the 7 consecutive days of lowest flow during any given year. The 7-day 10-year low flow (Q7,10) is a statistical estimate of the lowest average flow that would be experienced during a consecutive 7-day period with an average recurrence interval of ten years.

Operators can also seek to withdraw groundwater, but the rules for determining the allowable withdrawal amounts can be cumbersome. Water that is on or under the land, such as accumulated snowmelt, stormwater runoff, or water from a spring-fed pond, can be sold as long as it has no impact on water on or under another property. Although landowners may be considered to have certain ownership rights in subsurface waters on their property, they can incur liability if their sale of water adversely affects a well or spring on another property. Generally, it will be difficult for landowners to sell water.

2.2.4 Hydraulic Fracturing Water Quantity Update

The average quantity of water being used as the base fluid in a HVHF treatments in Pennsylvania has increased since the previous analysis was conducted in 2011. An analysis of the base fluid volumes disclosed to FracFocus from Marcellus and Utica wells drilled in Pennsylvania was conducted to identify trends and volumes for the states as well as for adjacent counties to the DRB. Data was obtained from FracFocus for wells fractured in 2013 through 2017. The information obtained included 4,515 records containing the API number, county, year fractured, producing formation, and total base volume. The largest volume reported was a Marcellus well in Butler County, 86,534,700 gals, and the smallest volume was 4,200 gals, on a Marcellus well in McKean County. The 5-year average volume for all disclosures over this period is 11,172,772 gallons (gals), for Marcellus-only disclosures (4,301) 11,132,875 gals, and for Utica only disclosures (72) 13,145,825 gals. The average volume as analyzed is approximately 2.75 times larger than the median volume needed to fracture wells in the Susquehanna River Basin.[33] The increase in base fluid volume is likely a result of longer lateral wellbore lengths, greater depths drilled, optimization of multistage fractures, and new fracture methods being employed. Corporate sustainability reports cite the large percentages of water that are being recycled and reused for both drilling and hydraulic

EXHIBIT 21: AVERAGE ANNUAL TOTAL BASE WATER VOLUME BY YEAR (FRACFOCUS DATA 2013-2017)

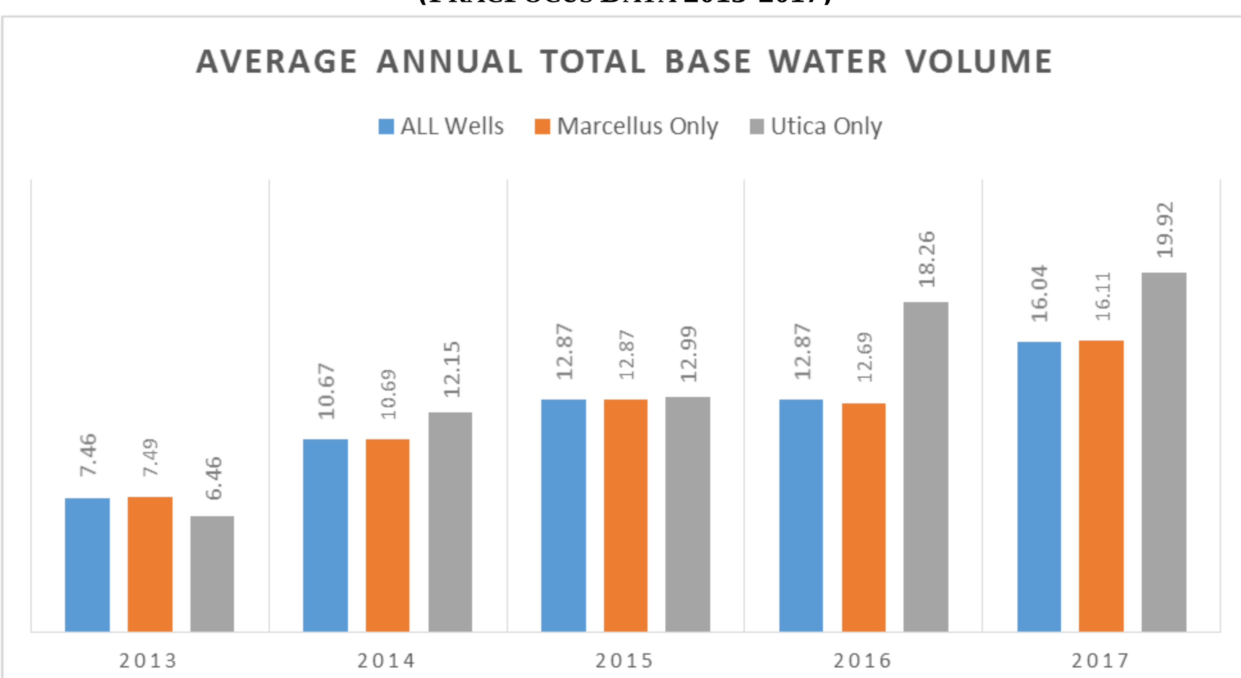
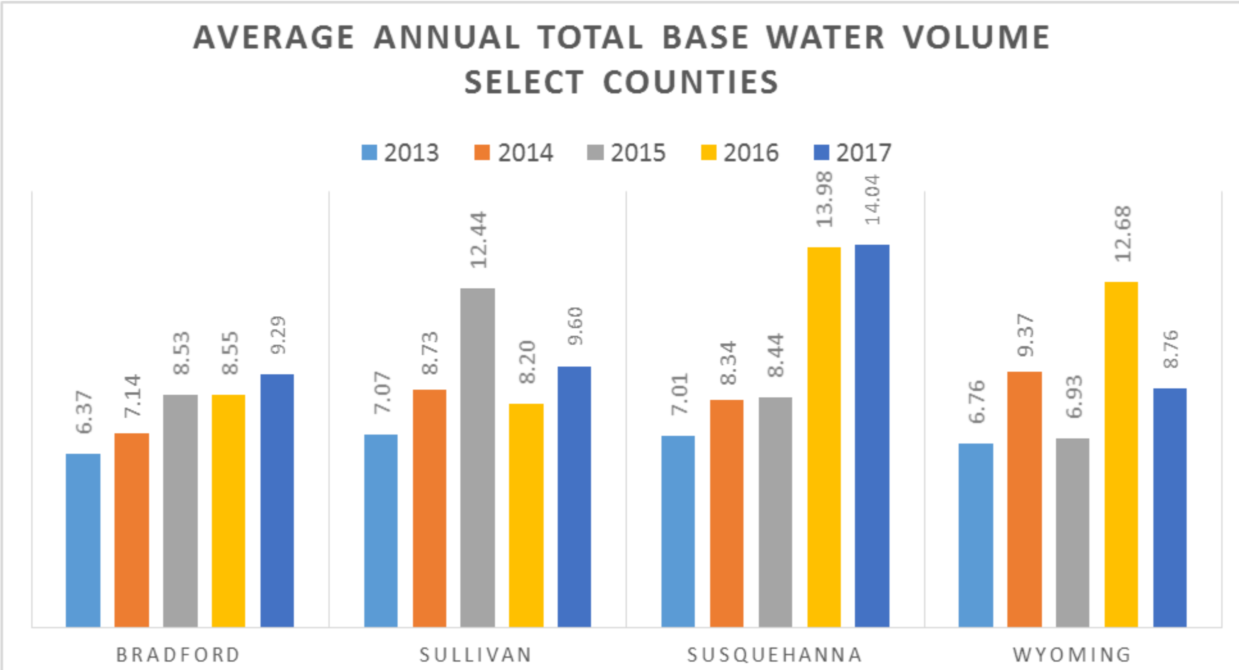


EXHIBIT 22: AVERAGE ANNUAL TOTAL BASE WATER VOLUME BY COUNTY (FRACFOCUS DATA 2013-2017)



fracturing, reducing operator's dependence on fresh and potable water sources.[34,35,36] **Exhibit 21** shows the annual average for total base volume for all unconventional wells fractured across the state, Marcellus only wells, and Utica only wells from 2013-2017. **Exhibit 22** provides the annual average total base volume for select counties near the DRB.

Using the 5-year average volume and the estimated development rate of 40 wells per year indicates that a total of ~447 Mgals or 1.22 Mgal/d would be withdrawn for natural gas development within the APE annually. The 1.22 Mgal/d represents 2.23% of the estimated USGS daily withdrawal for the APE and 0.81% of the DRBC reported withdrawals for the Upper Region. Since water for HVHF is considered a consumptive use the 1.22 Mgal/d would also represents an increase of 81.3% for consumptive water withdrawals in the Upper Region as compared to the current 1.5 Mgal/d being consumed as reported by the DRBC in Exhibit 19.

2.2.5 Water Quality Concerns

2.2.5.1 Special Protection Waters

Protecting water within the anticipated production extent of the DRB will involve the application of several best management practices (BMPs) suited to site specific conditions as the entire area is designated as Special Protection Waters (SPWs). Industry has a large assortment of BMPs that can be employed to address site specific situations and has done this successfully as demonstrated in both the ORB and SRB development efforts, see section 4.2 for a list of BMPs. Special Protection Waters are those that meet the water chemistry standards and the biological assessment qualifiers of Chapter 93 of the Pennsylvania Code Title 25, Sections 93.4b(a) [for High Quality Waters] and 93.4b(b) [for Exceptional Value Waters].[37] The PA DEP uses water quality to classify streams. The classifications consist of Exceptional Value (EV), High Quality (HQ) and Warm

Water Fisheries (WWF). The top classification constituting the highest level of protection is EV, the next classification down is HQ.

The Clean Water Act requires states to have protective uses for their surface waters. Once a protective use is established for a surface water, that use must be maintained and the surface water is not permitted to degrade.[38] Anti-degradation is a concept that has its roots in the federal Clean Water Act, and was promulgated by U.S. Environmental Protection Agency (EPA) for Pennsylvania 1996.[39] This PA DEP policy of anti-degradation promotes the maintenance and protection of existing instream water uses and the level of water quality in the state. The Pennsylvania Clean Streams Law reinforces the anti-degradation policy and was enacted to preserve and improve the quality of the Commonwealth's waters.

2.2.5.2 Spill Prevention Control and Countermeasures

To develop hydrocarbon resources in the DRB and protect the SPWs, operators will need to comply with state regulations and continue to implement various BMPs where required to provide a measure of safety when drilling and operating wells. There are numerous BMPs that address site selection, pollution prevention measures, site preparation, erosion and sediment control, waste disposal, well operation procedures, and well plugging and site reclamation activities. The chief concern of the DRBC is the potential for impacts to surface and ground water from accidental chemical spills during all stages of the hydraulic fracturing water cycle, as evidenced in their notice of public hearing for the proposed rule.[40] With this in mind, the focus of the following discussion is on the protection of water quality by utilizing advances in spill protection, containment, and countermeasures that have been applied by the industry in other areas of special designation.

Spill prevention control and countermeasure (SPCC) plans are required for all non-transportation-related onshore oil and gas facilities that are reasonably expected to have a discharge into navigable waters of the United States.[41] Again, these requirements and plans are well understood by operators and developed based on site-specific criteria but generally only address the tanks that store oil or produced water, and are not required for equipment and other chemicals stored on site. To account for this operators have developed and implemented zero-discharge and controlled-collection well pad containments for use in sensitive environments, much like what might be experienced in the DRB. Examples are provided in the following two subsections.

2.2.5.2.1 Zero Discharge Well Pad

The zero-discharge well pads include full pad liners with decking, perimeter berms, stormwater collection systems, gasketted cellars, and employee secondary containment for fracture tanks and chemical storage. **Exhibit 23** provides a series of photographs with captions that depict elements of a zero-discharge pad.[42] **Exhibit 24** provides a cellar containment design.

EXHIBIT 23: ZERO-DISCHARGE WELL PAD

Well Pad Liner and Subbase Materials

Decking Placement

Well Pad Liner Berm

Perimeter Berm Liner and Geofrabic

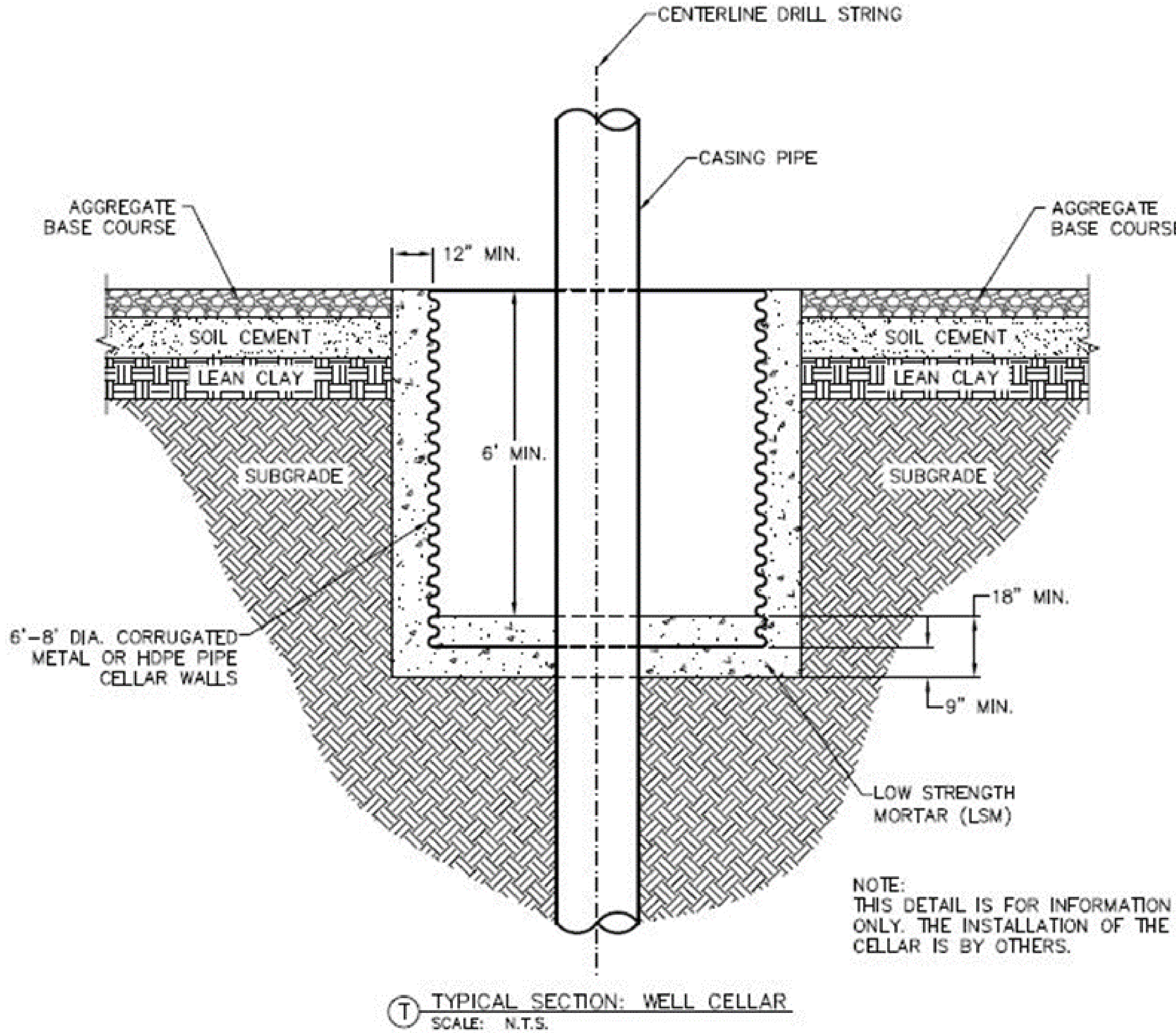
Cellar with Rubber Gasket

Grounding Rod Outside Containment

Frac Tanks / Manifold in 2nd Containment

Frac Chemicals in 2nd Containment

EXHIBIT 24: CELLAR DESIGN AND COLLAR FOR ZERO-DISCHARGE WELL PAD



The containment capacity of the zero-discharge well pads is based on the area within the perimeter berm times the berm height minus the anticipated 25-year, 24-hour precipitation amount. For a typical unconventional multi-well pad the area within the perimeter berm is ~5.5 acres and the berm is generally 18" in height. The capacity for a pad with these dimension could hold ~2.693 Mgals or ~64,120 barrels (bbls) before accounting for any rainfall. The Rainfall Frequency Atlas of the United States reports the Upper Region of the DRB between 5" and 6" for the 25-year, 24-hour rainfall amount.[43] Using the median amount of 5.5", the capacity of the secondary containment around the pad with said dimensions would hold ~1.87 Mgals or ~44,525 bbls, more than enough capacity to hold the volume of an accidental release during any single frac stage of a stimulation.

When these zero-discharge well pads are constructed there are several construction practices that are followed to prevent punctures during construction and operation activities. These practices include the following:

- Liners are installed smooth and wrinkle-free so when decking is placed there are no pinch-points which might result in potential tears.
- Liners are folded all the way over the perimeter berm and covered with soil on back side to lock them down.
- Liners have seams welded with heavy-duty plastic.
- Decking placement tools are modified so there are no sharp edges that contact liners.
- Interlocking rig mats or decking are used and damaged decking pieces are removed as they can puncture liners.
- Pad liner and perimeter berms have drive-over protection (ramps) installed to prevent crushing and to maintain the integrity of the containments.
- Access points are restricted to areas with proper ramp structures.
- The cellar is pre-set with conductor casing and embedded in low slump mortar (LSM) prior to the drill rig arrival.
- Cellars are monitored frequently to keep fluid levels pumped down.
- Grounding rods are placed outside containment so they do not penetrate the liner.
- Frac tanks, manifolds, chemicals, and diesel generators are placed in additional secondary containment (tertiary) to prevent accidental leaks from entering the environment.
- Spare equipment or materials are not stored against the perimeter liner as they could tear the liner.
- If a mouse hole is required because of the type of drilling rig used it the bottom of the tinhorn is embedded in the LSM preventing the escape of fluids.

2.2.5.2.2 Controlled-Collection Well Pads

Controlled-collection well pads differ from zero-discharge pads in so much that they do not use full surface liners with decking but rather employ an engineered surface that utilizes a soil cement and aggregate base surrounded by a compacted clay soil berm and a drainage collection trench or swale. Secondary containment for tanks, equipment, and chemicals is still used on these pad surfaces. These types of well pads designs can prevent off-pad releases of spilled liquids. The collection systems are designed to slow and control spills for recovery efforts. If part of a spill avoidance and cleanup program, these controlled-collection systems can help with regulatory acceptance of spill prevention and mitigation planning. **Exhibits 25** and **26** provide typical section designs for controlled-collection exterior berms with perimeter drains and with swales. **Exhibit 27** shows an interior perimeter drain installation.

The perimeter drain requires less space and does not have an open trench, but has only ~2/3 the fluid collection capacity of the swale design and runs the risk of the drain pipe and aggregate being fouled. The swale and berm design has a large holding capacity and allows for regular visual inspections, but requires more space, is susceptible to freezing and can be damaged by vehicles.

The perimeter drain design uses collection sumps that are installed in the corners of the well pads. The sumps receives runoff or other liquids from buried perforated drain pipes around the perimeter. Accumulated stormwater is sampled and those samples are sent for laboratory analyzed. If analytical results indicate that impurities are present, the collected water is removed by a vacuum truck and disposed of properly. If analytical results are acceptable, the collected water is released from the sump to the surface through a valve flow line at the base of the sump.

EXHIBIT 25: EXTERIOR BERM AND SWALE TYPICAL SECTION

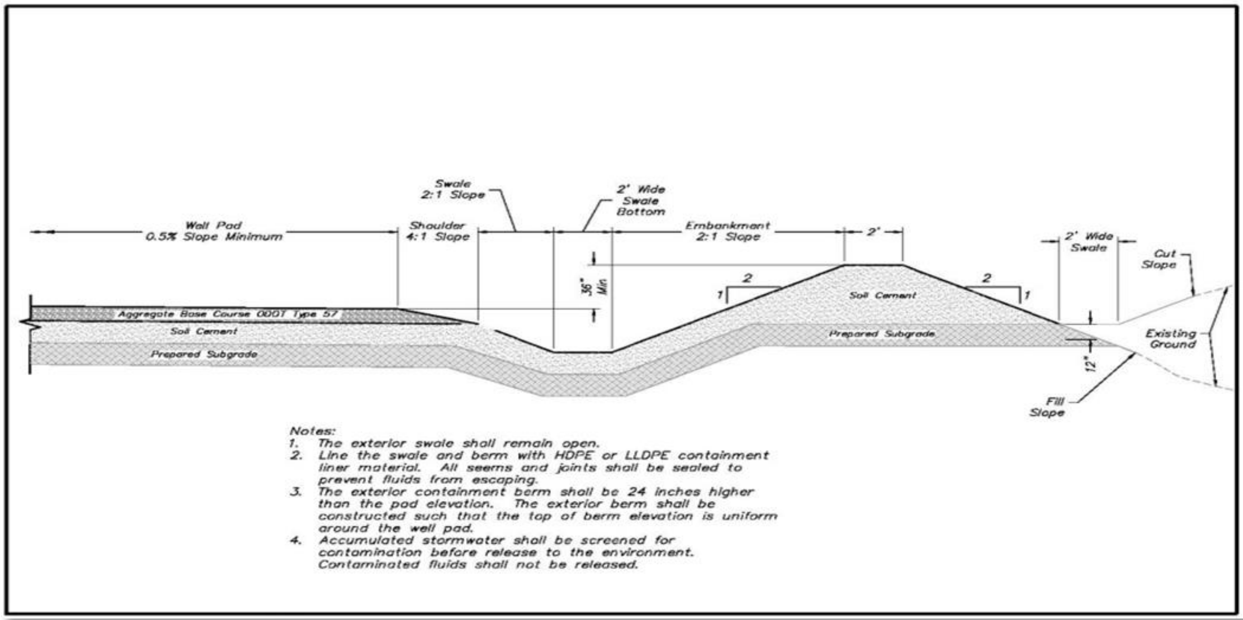


EXHIBIT 26: EXTERIOR BERM AND PERIMETER DRAIN TYPICAL SECTION

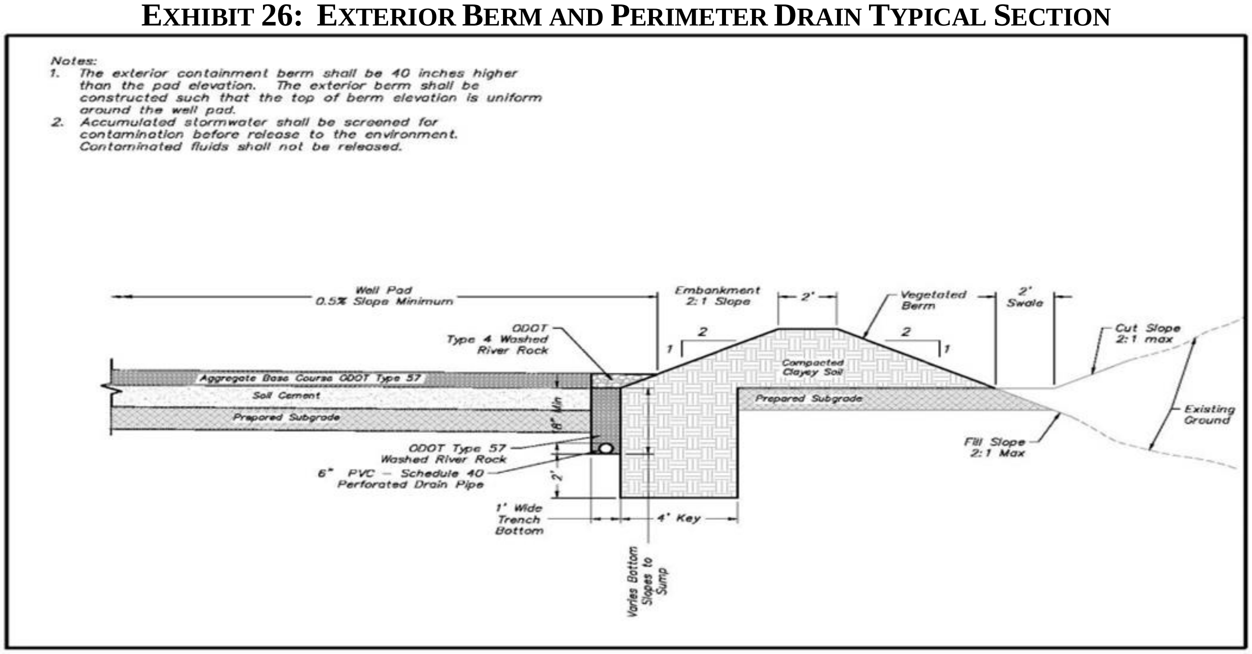


EXHIBIT 27: CORNER CATCH BASIN INSTALLATION (PERIMETER DRAIN)

Perimeter Drain with Perforated Pipe Trench

Bentonite Being Placed around Anti-Seep Collars

Catch Basin Installed before Backfill

Compacting Backfill around Catch Basin

Rip Rap Apron around Catch Basin

Perimeter Catch Basin

2.2.5.3 *EPA Study of Hydraulic Fracturing and Potential Drinking Water Impacts*

It has been just over a year since the EPA released their final report regarding the potential impacts of hydraulic fracturing on drinking water resources.[44] The final report acknowledges and incorporates many of the critiques identified during the peer review conducted by the EPA's independent Science Advisory Board (SAB); however, the oil and gas industry has questioned how the EPA derived its findings.[45] The study was initially understood to be an assessment limited to the actual process of hydraulic fracturing and its potential effect on drinking water. It later became a wider review of the "life cycle" of water during drilling and completion operations. The study evaluated hydraulic fracturing water cycle activities, including water acquisition, chemical additive storage and on-site mixing, hydraulic fracturing stimulations (i.e., the actual injecting of the fluid to fracture the production formation), handling of the produced water returned to the surface after fracturing and during production, and the ultimate disposal or treatment and reuse of the returned produced water. Each of the water cycle activities is addressed individually in the report.

Initially, the EPA concluded in their draft report that they did not find evidence that the mechanisms[*] involved in hydraulic fracturing activities "have led to widespread, systemic impacts on drinking water resources in the United States."[46] The EPA did, however, identify specific instances where individual mechanisms have led to drinking water resource impacts, including drinking water well impacts. They also acknowledged that the ratio of identified impact cases to the number of wells hydraulically fractured is very small. The EPA further explained that this finding may be the result of insufficient pre- and post-fracturing data on the quality of drinking water resources; the scarcity of long-term systematic studies; the proximity of other sources of contamination preventing a definitive link between hydraulic fracturing mechanisms and an impact; and the inaccessibility of some information on hydraulic fracturing activities and potential impacts.

This conclusion and recognition of the findings' limitations did not alleviate concerns raised by the SAB peer review regarding the clarity and adequacy of the support behind these findings. The SAB expressed their concern, stating that they found them to be ambiguous and inconsistent with the data, observations, and levels of uncertainty discussed in the draft report. Specifically, the SAB indicated that the EPA did not support its conclusion quantitatively regarding the lack of evidence for widespread, systemic impacts of hydraulic fracturing on drinking water resources, and did not present the local or regional scale of impacts, define the terms "systemic" and "widespread," nor clearly describe the system(s) of interest (e.g., groundwater, surface water). This critique of the draft findings prompted the EPA to revise their findings in the final report. The EPA indicated in their response to the SAB that they agreed that the concluding sentence could not be quantitatively supported given the existing data gaps and uncertainties. Additionally, the EPA recognized that the conclusion sentence in the draft report was understood by various readers in many different ways, thus signifying that it did not express the findings of the draft report clearly. Consequently, the sentence was removed from the final report.[47]

In the final report the EPA expressed that hydraulic fracturing activities can impact drinking water resources under certain circumstances.[48] The report identifies certain situations where impacts from hydraulic fracturing water cycle activities can be severe or recurrent:

- Water withdrawals during times or in areas with low water availability, principally where diminishing groundwater resources exist;

[*] These mechanisms include water withdrawals in times of, or in areas with, low water availability; spills of hydraulic fracturing fluids and produced water; fracturing directly into underground drinking water resources; below ground migration of liquids and gases; and inadequate treatment and discharge of produced water.

- Large-volume spills of hydraulic fracturing fluids, additive chemicals, or produced water that result in high concentrations of chemicals reaching groundwater resources;
- Fracture stimulations on wells with insufficient mechanical integrity, letting gases or liquids migrate to groundwater resources;
- Injection of fracturing fluids directly into groundwater resources;
- Discharge of undertreated produced water to surface water; and
- Disposal or storage of produced water into unlined pits.

The EPA again included an explanation of the findings that recognized gaps in the data and uncertainties restricted their complete understanding of the potential local and national impacts on drinking water resources; therefore, they could not characterize the severity of impacts, nor estimate the potential frequency of impacts on drinking water resources.

The EPA's revision of the conclusions motivated the three members of the SAB with industry experience to co-author a subsequent report summarizing the study and their experience serving on the SAB.[49,50,51] This summary identifies a series of factors that the authors assert affected EPA's study process. Foremost was the lack of oil and gas industry knowledge and consultation, data gaps, data interpretation issues, and pre-existing negative perceptions of hydraulic fracturing and the oil and gas industry.[52]

It was also observed that that the SAB members spent considerable time discussing fracture height growth, and if subsurface migration of fluids could access pathways and reach drinking water. It was explained that a study by Kevin Fisher and Norm Warpinski describing the natural limitations of fracture height growth was brought up multiple times, but this study did not make it into the report.

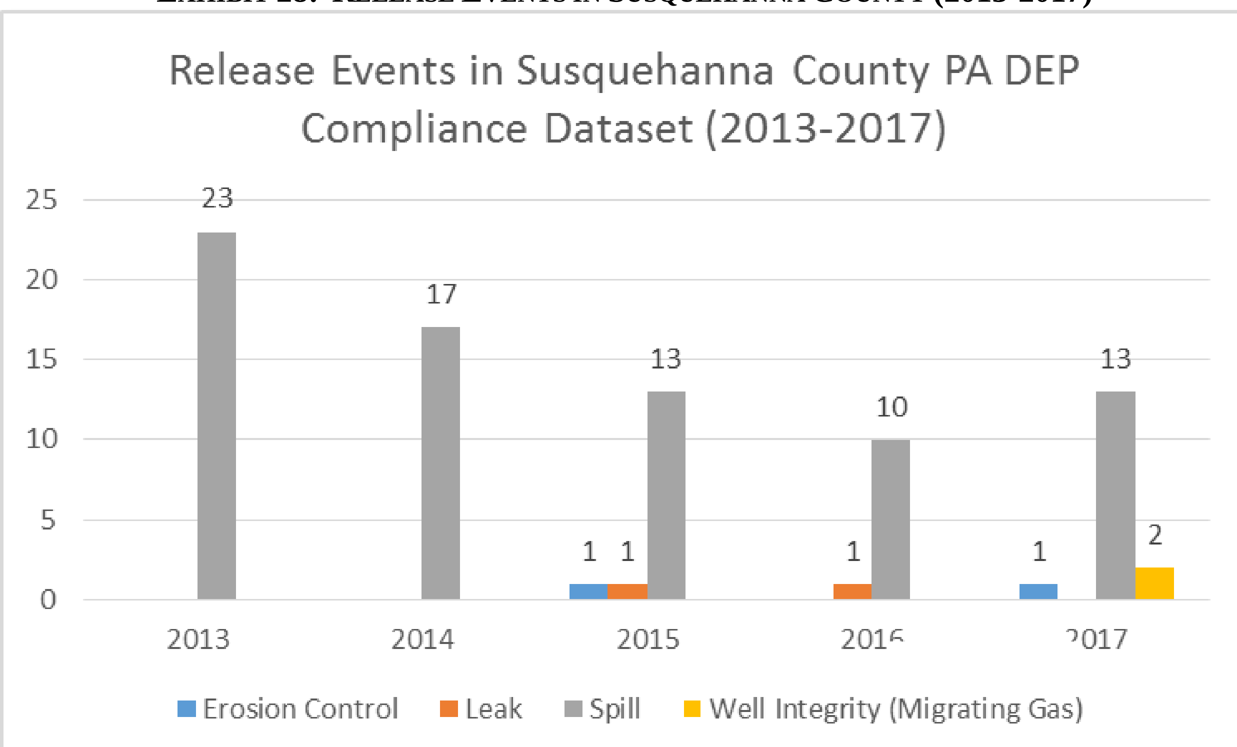
In the end, the industry members expressed their disappointment in the EPA study because it did not include any information about industry best practices to prevent spills, did not quantify risk or provide severity information, and did not include any substantive discussion of how hydraulic fracturing is regulated by states. The co-authors supported the conclusion of the original draft report and characterized it as "accurate, clear, concise, unambiguous, and supportive of the facts the EPA had reviewed."[53]

2.2.5.4 PA DEP Violations – Susquehanna County

To better understand the risk associated with the hydraulic fracturing water cycle mechanisms in Pennsylvania near the DRB, compliance data from Susquehanna County for years 2013-2017 was download from the PA DEP website.[54] We originally intended to analyze a larger sample of PA DEP compliance data but the data is presented without immediate violation identifiers so that it can be easily configured to identify spills with material type, quantity, cause, severity, etc. The data instead requires one to read the inspectors notes to extract the spill data of interest if recorded. This would be impractical for the entire state or multiple counties. Therefore, five years of data from the adjacent county with prolific development can serve as an indicator of potential development incidents for the DRB anticipated production extent. There are ~1,431 unconventional wells operating in Susquehanna County of which 781 have been drilled and hydraulically fractured from 2013-2017.

The results of this data request identified inspections* of 112 wells at 89 pads. The inspections produced 310 violations and 61 enforcements actions. There were 82 incidents related to potential surface- or ground-water impacts identified, 76 spills, two leaks, two lack of erosion control, and two well integrity issues. Of these 82 incidents involving the release on materials only six were cited for a 401 violation indicating that the discharged substance may have reached the Waters of the Commonwealth. The six incidents included three produced water spill in 2013, and two well integrity and one lack of erosion control incidents in 2017. The amount of sediment or natural gas that may have reached the Waters of the Commonwealth in 2017 were not quantified in the dataset but these events were identified early and short lived. The three produced water spills in 2013 involved one bbl (42 gals), 75 bbls (3,150 gals) and an unreported amount. **Exhibit 28** shows these incidents by year, **Exhibit 29** identifies the materials release by year and the max volume in gallons of any single release per year, and **Exhibit 30** shows the incidents by material type released per year.

EXHIBIT 28: RELEASE EVENTS IN SUSQUEHANNA COUNTY (2013-2017)



* Spills greater than 5 gallons are required to be reported to the PA DEP and these reports lead to site inspections, however not all inspections are a result of a reported spill, land owner complaint, spot, and unannounced inspections are also conducted.

EXHIBIT 29: MAXIMUM QUANTITY PER MATERIAL TYPE RELEASED BY YEAR (SUSQUEHANNA COUNTY)

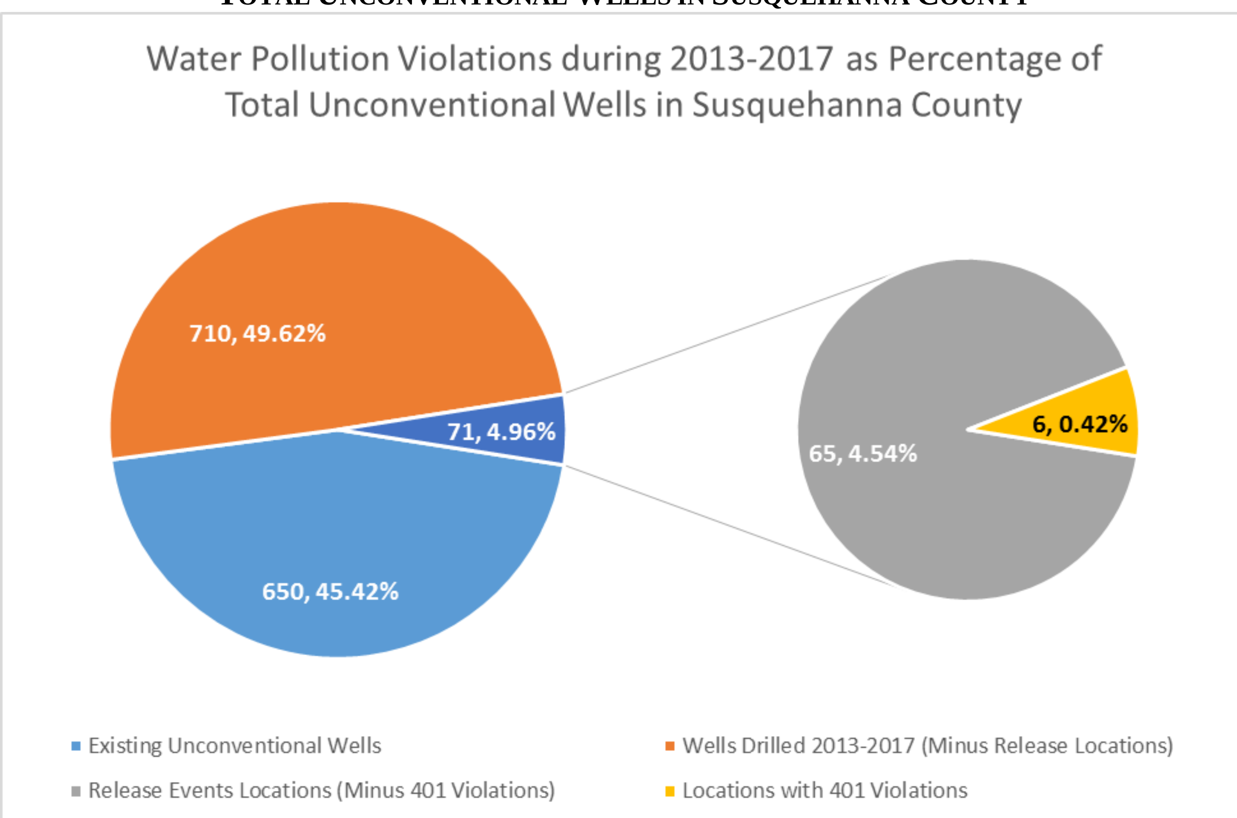
Material Type (gals)	2013	2014	2015	2016	2017
Antifreeze				10	1
Diesel Fuel	300	40	20	750	150
Ethylene Glycol	105				
Ferric Sulfate	200				
Frac Fluid (Water & Additives)	7560		1680		500.5
Frac Water (Fresh & Recycled)			10	200	
Glycol		210			
HCL Acid		7			
Hydraulic Fluid		2	21	15	
Lubricant	2.5				
Mineral Oil	840				
Oil Based Mud	5.5	420	84	3000	42
Produced Water	3150	3780	68	1000.5	126.5
Rigwash					500
Sediment					0
Unknown	5	0	0		
Water Base Mud	4200				

EXHIBIT 30: NUMBER OF INCIDENTS BY MATERIAL TYPE PER YEAR (SUSQUEHANNA COUNTY)

Material Type	2013	2014	2015	2016	2017	Total
Antifreeze				1	1	**2**
Diesel Fuel	2	1	1	1	2	**7**
Ethylene Glycol	1					**1**
Ferric Sulfate	1					**1**
Frac Fluid (Water & Additives)	2		2		1	**5**
Frac Water (Fresh & Recycled)			1	2		**3**
Gas					2	**2**
Glycol		1				**1**
HCL Acid		1				**1**
Hydraulic Fluid		1	1	1		**3**
Lubricant	1					**1**
Mineral Oil	1					**1**
Oil Based Mud	1	5	2	1	1	**10**
Produced Water	10	5	5	5	6	**31**
Rigwash					2	**2**
Sediment			1		1	**1**
Unknown	3	3	2			**8**
Water Base Mud	1					**1**
Total	**23**	**17**	**15**	**11**	**16**	**82**

It is also important to recognize that these 82 release events occurred at only 71 locations whereas there were 1,431 unconventional wells operating as of the end of 2017 and 781 new wells had been drilled over the five-year compliance review period. As a percentage, the locations with incidents account for 4.96% of the total operating unconventional wells and only 9.09% of the wells drilled during the period of 2013-2017 in Susquehanna County. The six events that were issued 401 violations for potentially reaching the Waters of the Commonwealth account for 0.42% of the total operating unconventional wells, 0.77% of the drilled wells in 2013-2017, and 8.45% of the locations with incidents. **Exhibit 31** graphically depicts the water violation events as a percentage of the total unconventional wells in Susquehanna County. Applying these percentages to the projected development rate for the DRB indicates that 3.63 (9.09% of 40 wells) release events would occur per year and there is less than a 0.5% chance that one of those events would potentially reach the Waters of the Commonwealth. It is understood that this analysis cannot completely forecast future events as there are numerous other factors to consider, such as: operator history, frequency of inspections, inspector due diligence, site location, operator environmental reverence, etc., but this does show that the mechanisms involved in hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in Susquehanna County.

EXHIBIT 31: WATER VIOLATIONS DURING 2013-2017 AS PERCENTAGE OF TOTAL UNCONVENTIONAL WELLS IN SUSQUEHANNA COUNTY



3 Economic Analysis

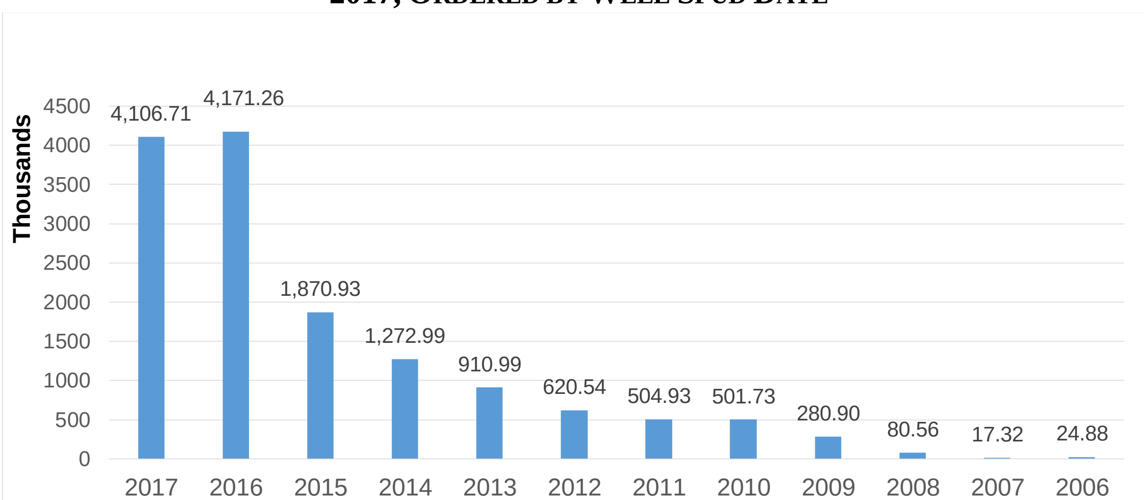
3.1 Drilling and Production

As described in section 2, ALL estimates that 40 wells per year would be drilled in the six DRBC counties combined if there is no HVHF ban (see **Exhibit 13**). This drilling rate is based on resource potential and historic drilling data.

In order to estimate the economic impact of this drilling, an estimate of production from these wells must be made. ALL looked at production data from a representative nearby county, Susquehanna County, which is just west of the DRBC area in question, and which has experienced shale drilling and production over the last several years. Production volumes for 2017 for wells in the county were downloaded from the PA DEP website and then ordered by spud date, so that the age of each well could be determined.[55] The 2017 production for wells spudded in each year were averaged.

Exhibit 32 shows the resulting decline curve averaged over the producing wells in the county. Production remains high for the first two years and then decreases. Average total production for the first ten years is ~14.3 billion cubic feet (Bcf).

EXHIBIT 32: AVERAGE SUSQUEHANNA COUNTY NATURAL GAS PRODUCTION PER WELL IN 2017, ORDERED BY WELL SPUD DATE



The wellhead price of natural gas will determine the value of this production, which determines the royalties that will be paid to landowners, and which is also correlated with the number of jobs that are generated by these wells. The EIA forecasts the future price of natural gas (but not the local or statewide price). EIA estimates that the Henry Hub price will average $3.06 in 2018, rising to 4.07 in 2025 and $4.17 in 2027, in 2017 dollars.[56]

Historically, the wellhead price of gas in the Marcellus region is lower than the Henry Hub price. The reason is that oversupply in the basin has saturated the Northeast gas market and new pipeline capacity has been blocked by protests and lawsuits. However, the differential between the wellhead price in the Marcellus play and the Henry Hub price has been narrowing as new pipeline capacity is added. That differential has decreased from over $1.50 per Mcf to around 90 cents per Mcf. As more pipelines are built and operating, that gap is expected to decrease even more.[57,58]

It is informative, therefore, to look at the value of the production from the representative well described above at different prices that may be received for the gas produced in the region, and in the six DRB counties in Pennsylvania, in the future. **Exhibit 33** shows the value of that production at $2, $3, and $4 per Mcf, for a single well with the decline curve shown above and for the 40 wells that are forecast to be drilled annually.

EXHIBIT 33: VALUE OF PRODUCTION FROM A REPRESENTATIVE PENNSYLVANIA MARCELLUS/UTICA SHALE WELL AND FROM 40 WELLS THAT WOULD BE DRILLED ANNUALLY

Wellhead Price ($/Mcf)	Value of ten years of production ($millions)	
	Single Well	40 Wells
2.00	$28.6	$1,146
3.00	$43.0	$1,719
4.00	$57.3	$2,291

There are number of economic impact studies that estimate jobs resulting from shale gas development. Some use input-output models to analyze the flow of investment and expenditures throughout the local economy. They can then use this analysis to develop simple multipliers. For example, Considine, et al., from Pennsylvania State University, using the IMPLAN model, find that each Marcellus Shale well in Pennsylvania generates $6.2 million in economic impact in the state.[59] Therefore, 40 wells per year would generate nearly $250 million of economic impact annually.

The same study concludes that every $1 million of gross output generated by Marcellus gas wells results in 6.8 direct and indirect jobs in Pennsylvania. Using the values of the natural gas production shown in **Exhibit 33**, this translates to a range of approximately 780 to 1,560 jobs created annually for every 40 wells drilled each year in DRB counties.

Alternatively, DeLeire, et al., estimate that each well generates between 4.7 and 5.8 new jobs two years out from spudding the well.[60] For 40 new wells per year, this comes to 188 to 232 jobs per year. Note that these are only the direct jobs generated in the mining and oil and gas sector.

The jobs directly associated with these wells are generally high-paying ones. As the shale gas industry was taking hold in the Marcellus region, the U.S. Bureau of Labor Statistics reported increasing pay for oil field workers in Pennsylvania, growing to almost $85,000 per year in 2012.[61] In January 2018, the website salary.com reported salaries for Oil and Gas Supervisors in Pennsylvania between $83,000 and $102,000 per year.[62]

In addition to oil and gas field workers, there are many other industry support jobs and jobs in associated sectors. Many people, such as landmen and attorneys, are required to identify prospective properties for leasing, write leases, and conduct related legal and regulatory work. Seismic surveys also require manpower, and create demand for local business services. Once a drilling site is located, site preparation and construction and drilling begins and with it the need for services, labor, and other locally supplied activities. If natural gas is found in commercial quantities, infrastructure such as well production equipment and pipelines are installed, which further stimulates local business activity.

Finally, as production flows from the well, royalties are paid to landowners. These expenditures stimulate the local economy and provide additional resources for community services, such as health care, education, and charities. The workers in the industry earn wages, which increase household incomes, which then stimulates spending on local goods and services. These impacts associated with household spending are called induced impacts. The total economic impacts are the sum of the direct, indirect, and induced spending, which are the result of the investment by shale gas producers. The total amount of these expenditures and their distribution across various industries and sectors can be estimated using input-output models which contain data on the flows among those sectors that result from investments. However, the extent of that kind of analysis is beyond the scope of this report.

3.2 Lease and Royalty Income

Leasing and production of natural gas resources generates revenue for the landowner in the form of lease bonus payments and royalties. Lease bonus payments are upfront payments by the producer to the landowner in exchange for the execution of a lease to produce oil and gas from the subsurface. The size of these payments are a function of the perceived resource potential (for example, payments may be higher if there are nearby producing wells), competition for leases, and the negotiating ability of the parties involved. They are usually paid on a per-acre basis.

While there will undoubtedly be lease bonuses paid in the six DRBC counties in the absence of a HVHF ban, the amount of those payments is very difficult to forecast. It is not determined only by the number of wells that are expected to be drilled. Many areas are leased, and bonuses paid, on speculation without ever drilling a well on the acreage. This may be due to nearby drilling experience that did not pan out commercially, to lack of capital to drill, to regulatory restrictions that make it impractical to drill, or for other reasons. Also, we do not know how much of the available resource has already been leased in these counties.

The amount of payments can vary widely and are especially uncertain in an area that does not have much drilling experience, as in these counties. There is anecdotal information on the size of bonus payments in the Pennsylvania Marcellus area. They may range from a few hundred dollars per acre to $2,500 an acre and possibly more.[63,64]

To get an idea of the magnitude of payments that might be made in the six counties in question, assume that 10%-20% of the accessible acreage, as shown in section 2, is leased with bonus payments ranging from $500 to $2,500 an acre. The accessible, unrestricted area is approximately 201 square miles (see **Exhibit 7**) or 128,640 acres. The range of lease bonus payments on 10% (12,864 acres) to 20% (25,728 acres) of this unrestricted acreage is shown in the following table.

EXHIBIT 34: SAMPLE LEASE BONUS TOTALS IN THE SIX DRBC COUNTIES

Bonus Payment per Acre	10% of unrestricted land	20% of unrestricted land
$500	$6,432,000	$12,864,000
$1000	$12,864,000	$25,728,000
$2500	$32,160,000	$64,320,000

This acreage may be a very conservative estimate of the amount of future leasing. While the accessible surface area is restricted by regulatory setbacks, flood zones, and forested areas, oil and gas leases address the amount of subsurface acreage to be accessed. Horizontal drilling may reach two or three miles from the surface location of the wellhead and therefore can access many times the area that is unrestricted at the surface. Lease bonuses would pay for the subsurface acreage to be produced rather than the surface footprint.

Once wells are drilled and gas is produced, the landowner collects a royalty on the value of the production. Pennsylvania has a statutory minimum of 12.5% royalty on that revenue, but it can often be higher. In one recent example, Chief Oil and Gas signed a lease with the Pennsylvania Game Commission for a royalty in excess of 20%.[65] The following table shows the amount of royalties that would be paid on the first ten years of revenue from 40 gas wells (one year's estimated drilling) (see **Exhibit 35**) at three wellhead prices and two royalty levels.

EXHIBIT 35: ROYALTY TOTALS FOR TEN YEARS OF PRODUCTION FOR 40 WELLS THAT WOULD BE DRILLED ANNUALLY

Wellhead Price ($/Mcf)	Royalties for 10 years production, 40 wells ($millions)	
	12.5%	20.0%
2.00	$143	$229
3.00	$215	$344
4.00	$286	$458

3.3 State Taxes and Fees

3.3.1 Unconventional Gas Impact Fee

The wells that are projected to be drilled in the gas shales in the DRBC counties will generate revenue for state and local governments in the form of taxes and fees. This revenue would not be realized if there is a ban on HVHF. The state imposes an impact fee on unconventional gas wells and there are permit fees charged by the PA DEP for drilling permits. In addition, landowners, employees, and producers would pay income tax on lease payments, royalties, wages, and profits.

Pennsylvania is the only major gas-producing state that does not impose a severance tax on gas production. Rather, the state charges an impact fee on unconventional gas wells.[66] This fee is charged for each new gas well, starting in the year the well is spudded, and continuing for 15 years in decreasing amounts. The fee is set by the Pennsylvania Public Utility Commission and is based on the price of natural gas. It is also adjusted for inflation. In 2017, the fee for the first year, i.e., the year the well is spudded, is $50,700. It decreases to $10,200 in year 15. This is based on a gas price of $3.11 per Mcf. The fee would increase if the price of gas exceeds $5.00 per Mcf and would decrease if the price falls below $3.00 per Mcf.[67] Based on the EIA price projections cited above, it is expected that this fee would remain stable, adjusted for inflation, over the next ten years.

Under the current fee schedule, each unconventional natural gas well drilled in the Pennsylvania DRB counties would pay $314,700 over 15 years. Therefore, 40 wells drilled annually would pay $12,588,000. The projected 400 wells that would be drilled over the next ten years would pay a total of $125,880,000 in impact fees over their producing lives.

This revenue is distributed to state agencies, counties, and municipalities according to a complex formula that is specified in the law. In general, the first $25.5 million collected each year is distributed to a series of state agencies. Of the remainder collected, 60% goes to counties and municipalities that have unconventional gas wells, and 40% is distributed to all counties in the states as well as a fund for infrastructure improvements and environmental stewardship.[68] Thus, these wells will directly benefit state and local agencies and governments across Pennsylvania through distribution of the impact fee.

3.3.2 Drilling Permit Fees

The PA DEP charges a fee for the drilling permit needed to drill a gas well. This fee is based on the length of the wellbore, including both the vertical and horizontal sections. Therefore, in order to calculate the fee, we have to make assumptions about the wells that will be drilled.

The Utica Shale underlies most of the DRB area in question (see **Exhibit 4**). This formation ranges between 7,000 and 9,500 feet in depth in this area.[69] We will assume an average depth of 9,000 feet for the future wells in these counties. The lengths of the laterals for horizontally drilled wells has been increasing over time as technology and experience improve. A lateral length of 10,000 feet is reasonable, giving a total wellbore length of 19,000 feet. The PA DEP permit fee for a well of this length is $4,400.[70]

The Marcellus Shale is somewhat shallower than the Utica, about 6,000 feet in this area.[71] It lies under a small portion of Wayne County, and is underlain by the Utica Shale. Therefore, any Marcellus well here could also be drilled into the Utica as well. If limited to 6,000 feet in depth, and with a 10,000 foot lateral, the permit fee would be $3,900, just $500 less than the fee for a Utica well.

Assuming that 40 wells per year are drilled into the Utica Shale, the combined permit fees per year collected by the PA DEP would total $156,000[*]. Over ten years, the amount collected would be $1,560,000.

3.3.3 Income Taxes

Pennsylvania would collect state income taxes from individuals and corporations as a result of the increased economic activity from drilling unconventional gas wells in the DRB counties. These taxes would be collected on royalty and lease bonus income, wages, and corporate profits.

Individual income tax on royalty payments would be charged at the state's individual tax rate of 3.07%.[72] Based on the royalty amounts shown in **Exhibit 35** above, and applying this income tax rate, the amount of taxes collected for royalties received from 40 wells over 10 years of production would be as shown below in **Exhibit 36**. The table shows the amounts that would be collected depending on natural gas wellhead price and royalty rate that is agreed to between the landowner and the producer. For ten years' worth of drilling, i.e., 400 wells, the taxes collected would be ten times the amounts shown, between $44 million and $141 million. It should be noted that these amounts are only estimates in that each landowner's tax situation may be different, depending on other income and deductions, as well as tax structure. Some landowners may arrange other tax structures, such as limited liability corporations or partnerships, to receive the royalty income and therefore may pay taxes at different effective rates.

[*] The PA DEP is considering raising the permit fee in fiscal year 2019 so these amounts will potentially increase.

EXHIBIT 36: INDIVIDUAL INCOME TAXES ON ROYALTY INCOME FOR TEN YEARS OF PRODUCTION FOR 40 WELLS THAT WOULD BE DRILLED ANNUALLY

Wellhead Price ($/Mcf)	Taxes on Royalties for 10 years production, 40 wells ($millions)	
	12.5%	20.0%
2.00	$4.4	7.0
3.00	$6.6	$10.6
4.00	$8.8	$14.1

As described in the previous section, the amounts of lease bonus payments in the future is very uncertain. However, **Exhibit 36** gives an idea of the magnitude of such payments to landowners given certain assumptions. Of course, these landowners would pay state income taxes on that income. The table in **Exhibit 37** below applies the state income tax rate to those amounts.

EXHIBIT 37: STATE INCOME TAXES ON LEASE BONUS PAYMENTS UNDER DIFFERENT BONUS LEVELS AND ACREAGES LEASED

Bonus Payment per Acre	10% of unrestricted land	20% of unrestricted land
$500	$197,462	$394,925
$1000	$394,925	$789,850
$2500	$987,312	$1,974,624

Other income taxes would be paid by wage earners employed by the gas producers, by companies that support those producers, and by associated sectors, such as hotels and restaurants used by those workers. In addition, the income earned by those workers would be spent on the local economy and further increase wages in the area, leading to increased income taxes. The flow of those wages is complex and is modeled by input-output models in a number of studies of economic impact.[73] Such an analysis is beyond the scope of this report. In addition, there is uncertainty about what those workers would be doing in the absence of this drilling activity. Some may travel to Pennsylvania from other regions. Their wages would be a true increase in the income of the local area. The same would be true for unemployed workers who are hired due to gas development. Some may be working locally in other sectors and choose to work in the gas fields because of higher pay. In those cases, only the taxes on the incremental wages should be counted as an increase in state revenues. Those assumptions and analysis likewise are beyond the scope here. There would certainly be income to the state from additional personal income taxes.

Similarly, state corporate income taxes will be assessed on profits realized by the gas producers, which are determined by the cost of the wells, operating expenses, and revenues. Once again, there will also be increased economic activity in other sectors of the economy as a result of the drilling and production of new wells, and input-output analysis is needed to track the flows of those dollars and resulting profits and taxes.

4 Landscape Alterations

It has been asserted that hydraulic fracturing alters the landscape and poses risks to high value water resources in the DRB and that the development and subsequent disturbances would impact the drainage area of Special Protection Waters.[74] This section attempts to quantify landscape alterations that might affect water quality during HVHF activities in the DRB.

4.1 Quantity of Potential Disturbances

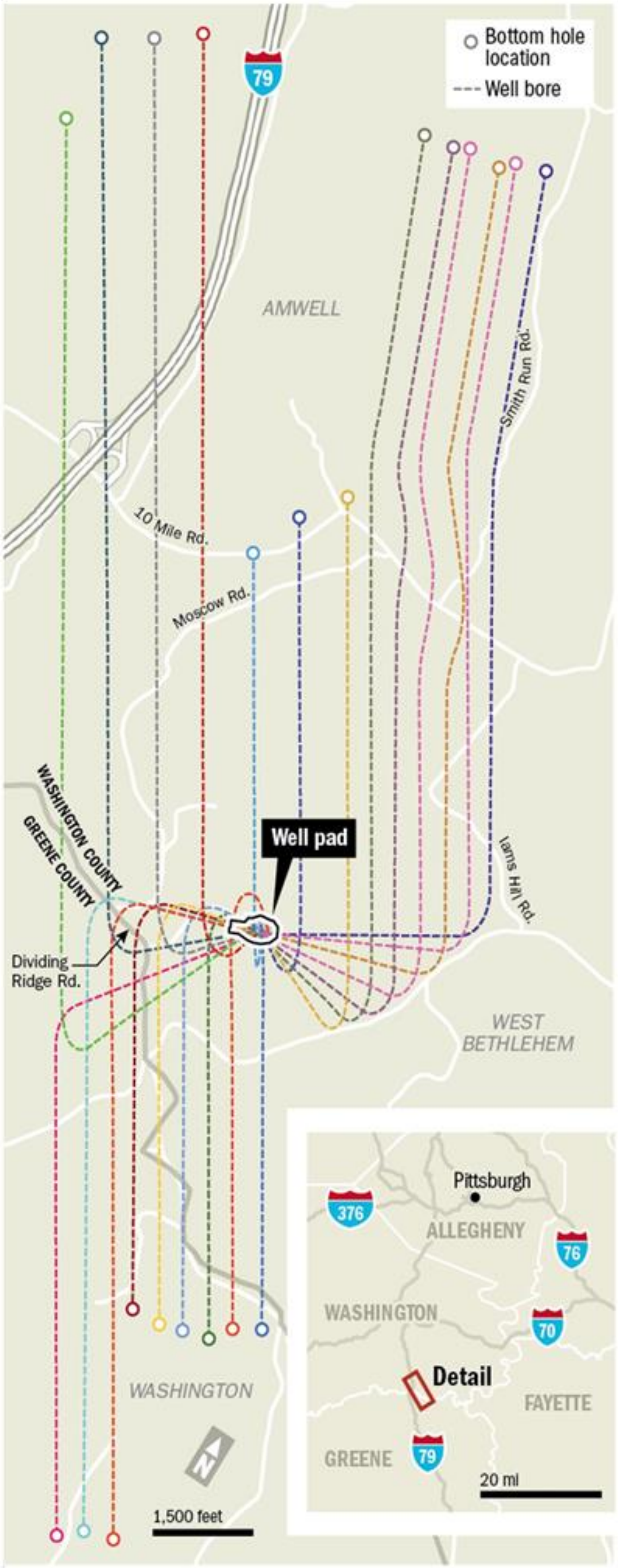
Advances in horizontal drilling and hydraulic fracturing have led operators to be able to drill longer lateral wellbores, multi-lateral wells, and batch drilling or developing more than one well on a pad.[75] A study from the Fall of 2014 states there are an average of five wells per pad in the Marcellus, however, a couple of recent articles indicate the industry's trend is to go large with companies now placing 10 to 20 wells per pad with plans to go even bigger, as much as 40 wells per pad.[76,77] [78] These larger sites means fewer well pads in total and a 10-acre surface area can theoretically extract natural gas from underneath an area nearly the size of a city (35,000 acres).[79] Operators have discovered that drilling as many wells, and as long a lateral as technology or land constraints will allow, is the most efficient and economical way to develop the resources. Other benefits include consistent well development, less truck traffic, smaller overall footprint, less access roads and right-of-ways, contained water management, and improved compliance. The dimensions of the pad are determined based on the total number of wells and the associated surface equipment. Companies plot and plan how rigs will be configured on the pad, drill order of wells, where completions equipment is placed on site, and how the permanent production facility will function. Planning each pad allows optimal use of space. **Exhibit 38** shows the EQT Corporation's Cogar pad, a 10-acre pad in Amwell Township, PA that holds 22 unconventional horizontal shale wells.[80] **Exhibit 39** shows an aerial view of a 2013 Cabot Oil & Gas pad with 10-wells in PA.[81]

With regards to lateral lengths, it was reported that Range Resources is averaging 6,000-foot laterals, CONSOL on the other hand is reaching 8,000-foot laterals, and EQT Corp. reported the current "economic and technological limit" is 21,000 feet, or 4 miles in the Marcellus. Considering how much the industry has changed in the past five years in Pennsylvania alone, it is safe to say all development quantities are subject to frequent and rapid changes.

To quantify the potential surface disturbances from projected HVHF development in the DRB within the available surface of the anticipated production extent (APE) area one needs to consider the annual rate of development and the likely placement of well pads and the number of wells on each pad. The rate of development as projected (Exhibit 13) suggests that approximately 40 wells per year could be development in the APE of the DRB if the commission were to impose similar restrictions and setbacks as outlined in Article 7[*] (2010) versus the complete prohibition of HVHF as is currently proposed. A deeper look at the estimate affirms that the wells would be spread out over the five counties at approximately 5 wells per year per county with the exception of Wayne County where both the Marcellus and Utica shales are present and 15 wells per year are estimated.

[*] Note, the Article 7 analysis should not be construed as an endorsement or agreement with the previously proposed regulations it is merely a case study to determine if the anticipated gas development could be conducted with restrictions in place that are protective of the DRB versus the complete prohibition of any development, thus indicating that other options are practical.

EXHIBIT 38: EQT CORP. – COGAR WELL PAD



Source: Pennsylvania DEP, EQT Corp., Ed Yozwick- Post-Gazette

Wells per year does not correlate directly to well pads per year as the economics of developing hydrocarbons, optimum well spacing, and technical challenges, coupled with the constraints of drilling in the in the DRB would affect quantity and placement of wells. Therefore, we think existing operators would take a cautious approach to development in this thermally mature region of the Marcellus and Utica and develop multi-well pads with at least five wells per pad initially. This would allow operators to maximize productivity and efficiency as well as take advantage of the limited surface available without docket or approval requirements in the DRB. This approach suggests that only one well pad would be developed per county per year, except for Wayne County which would experience three pads annually. This means the number of pads developed the first year drilling is allowed would be eight and subsequent years could see eight pads each or existing pads could be expanded to hold 10 or more wells thereby reducing the number of new pads annually. The 10-year development estimate called for a total of 400 wells therefore the number of pads over this duration would range from slightly less than 40 to a maximum of 80.

The average surface area impacted as a result of constructing a multi-pad with road and utility access, and processing and water management areas is approximately 11.5 to 15 acres.[82,83] Applying the average acreages altered per well pad to the number of well pads anticipated to be developed each year under the 5-wells per pad or 10+ wells per pad scenarios generates an anticipated annual acres altered per year estimate. (see **Exhibit 40**). Under the 5-wells per pad scenario there would be eight pads developed annually altering an estimate 120 acres annually (8 pads x 15 acres each)

EXHIBIT 39: 2013 CABOT OIL & GAS PAD WITH 10 WELLS

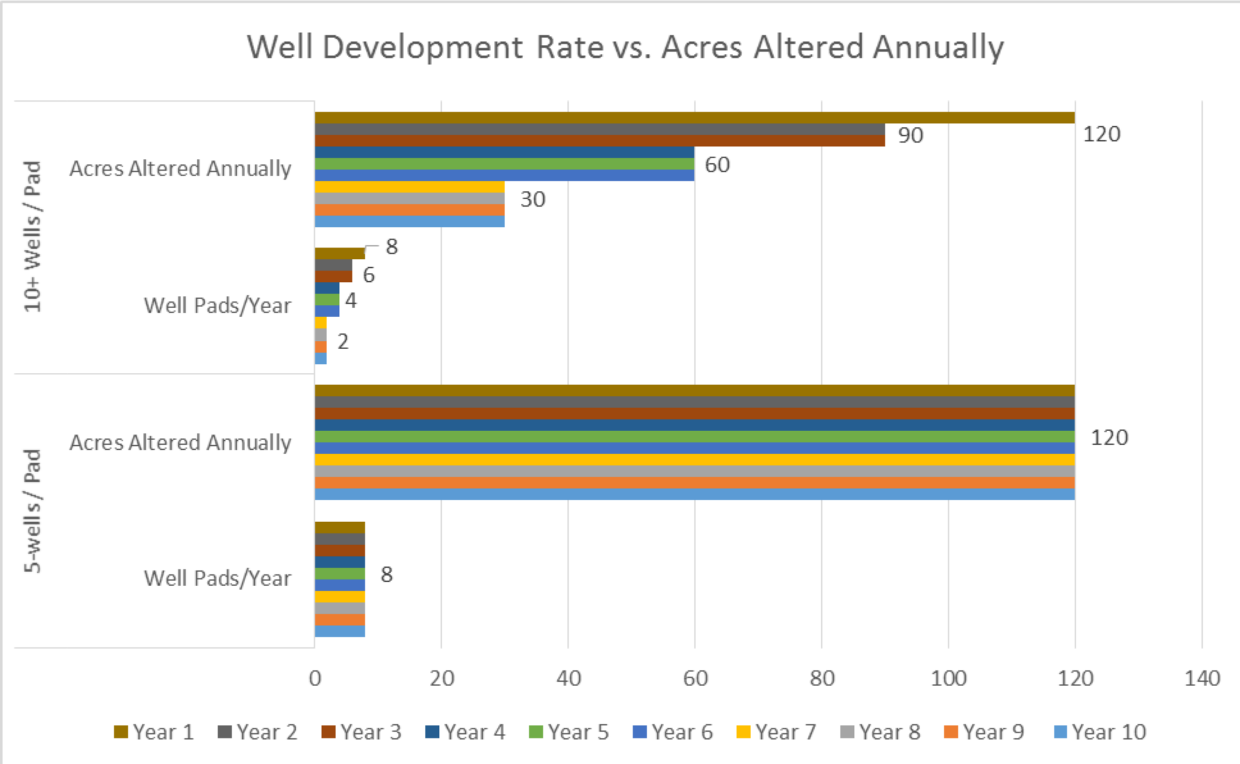
Source: Cabot Oil & Gas, Siemens - The Vault

resulting in a total of 1,200 acres (1.87 sq. miles) altered over the 10-year development period. Under the 10+ wells per pad scenario there would be eight pads the first year but as wells are added to existing pads the number of new pads per year would drop over the subsequent years resulting in only 40 pads and half the altered acreage at 600 acres (0.94 sq. miles).

As a well transitions from the drilling and completion phase to the production phase, land disturbance is reduced as a result of restoration activities for the well pad and associated facilities. Additionally, BMPs can be employed to effectively address erosion and sedimentation control during both the construction and operational phases of a natural gas development project.

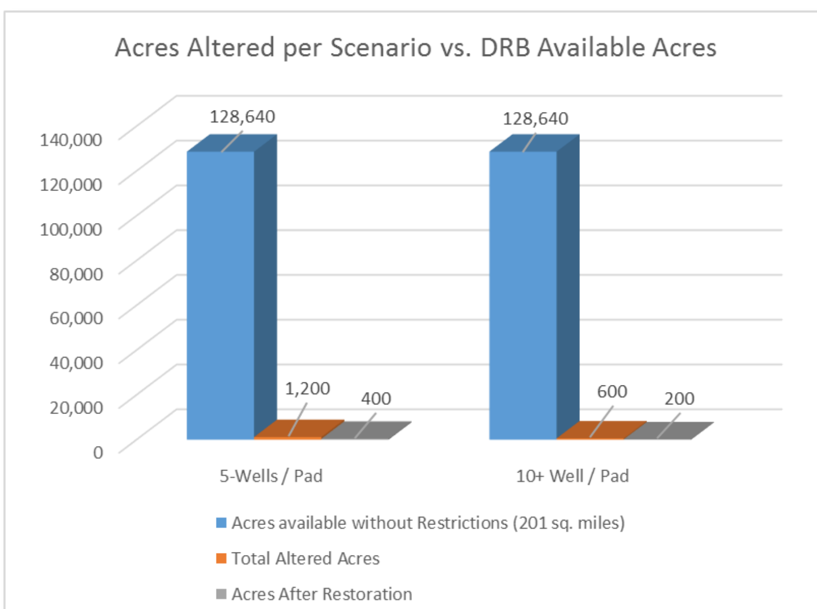
It should be noted that these altered acre totals do not account for restoration activities once the initial drilling and fracturing operations are complete. Restoration typically includes revegetation, reversing compacted soils, contour adjustments, etc. At the completion of restoration activities approximately 3.5 to 5 acres per pad site remain altered depending of road lengths and processing equipment remaining on site.[84,85]

EXHIBIT 40: ESTIMATED ACRES ALTERED PER YEAR BY DEVELOPMENT SCENARIO



The remaining altered acreage after restoration efforts over the development period for the two scenarios results in 400 acres for the 5-well per pad scenario and only 200 acres for the 10+ wells per pad scenario. **Exhibit 41** depicts the altered acreage by scenario as compared to the surface available without restriction as identified in **Exhibit 7**.

EXHIBIT 41: ALTERED ACREAGE PER SCENARIO



Land use requirements for natural gas development are a factor to be considered with respect to construction practices and controlling sedimentation and erosion to maintain basin water quality, the overall footprint would be relatively small and temporary. The percentage of land remaining altered under each scenario as compared to the acreage available without restriction is miniscule at 0.311% and 0.155% respectively. The percentage of land remaining altered as compared to the total acreage within the anticipate production extent (1,787 sq. miles or 1,143,680 acres) of the DRB is infinitesimal at 0.0350% and 0.0175% respectively.

4.2 Quality Impacts

The freshwater quality at any location in the DRB echoes the cumulative effects of numerous influences along waters path. Anthropogenic undertakings on landscape scales can affect both water quality and quantity. Changes in the land cover and land management practices have been recognized as crucial factors influencing the hydrological system, via changes in runoff as well as water quality. There have been several waves of research that tried to reveal the effects of land use and land cover changes on the quality of surface water.[86] Impact of human landscape alterations and management decisions such as controversial agricultural practices, large residential developments, and industrial uses was studied by the EPA in the late 1990's to generate and develop models and tools to evaluate alternative scenarios and compare potential impacts.[87] This EPA study generated numerous papers and presentation but of interest are the models that were developed and can be used to evaluate the projected development scenario in the anticipated production extent of the DRB to provide a more definitive assessment of the potential impacts. A water quality model, SWAT (Soil and Water Assessment Tool) which has been used to evaluate watersheds with regards to alternative futures was developed under this study and is available for use with ArcView applications (GIS analysis).

Results of the SWAT model applied to the agricultural development scenarios, as well as the current landscape and a landscape representing the historic past, of the study area under investigation indicated that substantial decreases in nutrient and sediment export from agricultural watersheds could be achieved if practices involving input reductions and increases in perennial cover were employed over extensive areas of the agricultural landscape. Fortunately for the DRB the footprint for natural gas development as estimated for the 40 or 80 well pads is tiny and would be constructed in locations most likely without tree cover and only affect perennial covered areas for a relatively short duration (<1years per pad site) before restoration activities were instituted. This development pattern within the DRB unrestricted surface cover would emphasize the application of BMPs for sedimentation and erosion control as well and spill control to avoid even minor events that might affect water quality.

Well field-related erosion is typically a result of pad site construction, access road development, widening of existing roads, installation of pipelines, and placement of production facilities. These activities can be controlled with the use of various BMPs such as:

- Protecting bare soils from the wearing effects of water and wind.
- Reducing or preventing soils from being transported offsite to a stream, surface water body, or wetland.
- Conducting routine inspections of erosion and sediment controls after each rain event.
- Implement sediment controls with erosion controls.
- Divert drainage from off-site to reduce stormwater run-on.
- Eliminate direct discharge to surface water.
- Construct a stabilized entrance or wheel wash to reduce mud on streets/ roads from vehicle drag out.

- Stabilize roads with crushed rock.
- Stabilize embankments.
- Minimize area of disturbance.
- Limit activities during rainfall.
- Rock construction entrance.
- Establish buffers for sensitive areas.
- Water bars or broad based dip in roadways
- Permanently stabilize ditches and drainage with grass or rock.
- Culvert pipe rock apron (inlet/outlet protection).
- Erosion control batting/mat.
- Riprap (armoring).
- Geotextiles (separator fabric).
- Level spreaders.
- Surface roughening.
- Terracing.
- Watering for dust (wind).
- Temporary and permanent seeding.
- Mulching.
- Hydro seeding.
- Re-establish vegetation cover promptly.
- Silt fence or super silt fence.
- Silt sock or compost filter sock (wattles).
- Straw or hay bale barrier.
- Gravel or stone filter berm.
- Sediment trap or filter bag.
- Ditch check (silt sock or rock).
- Brush pile sediment barrier.
- Vegetative filter strip.

There is a myriad of information available about each of the BMPs, however most critical might be the development of an Erosion and Sediment Control Plan as required by the PA DEP. Integral to these plans are the inclusion of a well site layout with grading and boundary, well pad grading plan, plan and profile of access road, location and size of erosion and sediment control devices, drainage area map, locations of wetland/ponds or stream nearby, soils map, temporary and permanent stabilization measures, construction details and specifications, construction sequencing, emergency containment map, and a maintenance plan/schedule. These measures combined with good oversight should reduce the chance of any development efforts regardless of size affecting the water quality long-term while conducting hydraulic fracturing water cycle mechanisms.

5 Water Treatment Technologies

While flowback[*] and produced water is commonly injected underground using Underground Injection Wells regulated under the Federal Safe Drinking Water Act, not all areas have suitable geology for such wells. In addition, that water can represent a valuable resource that can substitute for fresh water. A common solution is to recycle the water for use in fracturing other wells.

The objective when treating water to recycle it for hydraulic fracturing is to produce clean brine that is compatible with the fracture fluid chemistry being used, and to do so economically. Depending on the fracturing chemistry used, a water treatment process must be able to remove hydrocarbons, gelling agents, metals, hydrogen sulfide, iron sulfide, boron, and suspended solids. It has to be able to handle variable quantities and qualities of inlet water. In order for the economics to work, the water treatment must compete favorably with the acquisition of fresh water and disposal of produced wastewater. The goal for reuse of the produced water is to apply enough water treatment to condition the water so that it does not impact the fracturing fluid formulation/ effectiveness, proppant conductivity, or well productivity of the wells being fractured.

A multitude of technologies exist that are designed to remove specific constituents or a range of constituents from produced water. Generally, several technologies are used in combination. The number of process stages and technologies required for any specific project will be based on the type and concentration of constituents that must be reduced or removed to meet the water reuse specifications. Determining the most suitable treatment technology for re-use must take into consideration management alternatives, treatment drivers, economics, and regulatory requirements in addition to the chemical constituents present in the feed water.

Recycling the flowback and produced water in this way has a number of benefits. It directly offsets new source water demand for scarce fresh water resources, preserving that water for other uses. It reduces the volume of waste that must be disposed of and it economically produces clean brine water that can be used as a base for hydraulic fracturing of additional wells.

5.1 Water Compatibility for Use or Reuse in Hydraulic Fracturing

Reuse of flowback and produced water for additional hydraulic fracturing avoids putting that water back in the surface environment and has the additional benefit of reducing demand for fresh water. However, that water must be treated in order to be suitable for fracturing operations. The type of treatment needed depends on the geology where the well will be fractured as well as the characteristics of the water being recycled.

Produced water is also handled in a distinctly different manner in each of the shale plays. For example, in the Barnett Shale Play, a long history of production in the Fort Worth Basin area, coupled with favorable geologic conditions, has resulted in a relatively large injection disposal well network and available water floods. However, as water sourcing has become more complex, the water recycling market has increased in the Barnett Play. In the Fayetteville Shale, early water management was included in land farming of fluids; however, changes in regulation have

[*] The oil & gas industry generally does not use the term “flowback water” to refer to fluids generated from a well. Rather, the term “flowback” is used to refer to a process and all fluids generated from a well are recognized as “produced water.” However, the DRBC uses this term in its materials and therefore we echo that usage in this report in order to maintain consistency and make it clear for the DRBC and other reviewers.

eliminated land farming and now most produced water is hauled to other parts of the state or other states where injection disposal and water floods are available. The cost of hauling the water through these methods has resulted in the industry looking at recycling and re-use of produced water after treatment as a possible option. The Marcellus and Utica shales are similar to the Fayetteville with an overall lack of existing injection disposal infrastructure so disposal of produced water has involved a great deal of trucking of water. The size of the Marcellus and Utica play, the costs of source water, and limited disposal options have resulted in several operators moving to recycling using treatment technologies.

In addition, each of these shale gas plays has a distinct produced water character which, combined with the infrastructure differences, affects the management of this produced water. Water production profiles, water quality, and disposal options are also distinctly different for the major shale gas plays, requiring developers of this resource to adapt to each play in order to remain successful in developing these resources.

Treatment of source water for fracturing, whatever the source, nearly universally involves inhibition/removal of: (a) suspended solids, (b) micro-organisms, and (c) scaling ions. Reuse of flowback and produced water in subsequent operations can require removal of total dissolved solids (TDS) in addition to the removal of heavy metals and in some cases bacteria. Other treatment technologies, and sometimes multiple treatment technologies, must be implemented to reach the quality that is required for the selected management option.

Chemical additives typically used in the blended fluid to ensure its optimum fracturing properties include the following:

For total suspended solids control:

- Iron particulate inhibitors – to control scale formation with a neutral pH iron control agent, also preserving the activity of other scale inhibitors.
- Other scale inhibitors – for sulfates and carbonates, controlled by a blended scale control inhibitor.

For control of fracturing pressure and formation damage:

- Friction reducers (salt tolerant) – such as the nano-particle friction reducer (NFR) to maintain friction reduction enabling the high flow rate fracturing.
- Biocide controllers – control sulfate reducing bacteria, slime-forming bacteria, iron oxidizing bacteria, and more.
- Clay stabilizers – temporary (KCl) and longer-term inhibitors, now often low-toxicity clay stabilizers.

Numerous physical treatment options are available and applied to meet treatment goals of source waters for HVHF fluids. Commercial treatment processes and their applications for HVHF source waters are listed in **Exhibit 42**.

EXHIBIT 42: WATER TREATMENT PROCESSES AND APPLICATIONS

Water Treatment Processes	Methods	Applications
Suspended Solids Removal	• Settling: Oxidation and Precipitation • Settling: Chemical Flocculation and Precipitation • Settling: Electro Coagulation Enhanced • Desanders and Hydrocyclones • Auto Flush Sand Filters • Membrane Filtration: Micro, Ultra, & Nano Pores	• Precipitates iron and removes scale, polymers, bacteria • Removes dispersed solids including scale • Removes suspended solids and some ions • Removes particles to 50 microns • Removes particles to about 50 microns • Removes particulates to 1 micron
Oil and Grease Removal	• Separators / Skimmers • Flotation • Multi-media Filtration • Oxidation: Chloro Oxidants	• Oil removal • Remove fines and oil to less than 50 ppm • Adsorb some soluble organics, oily fines filtration • Destroy oil dissolved and as fine suspension
Scale Removal / Imbibition	• Scale Control with Chemical Addition • Oxidation • Settling and Filtering • Adsorption: Ion Exchange Resins, Activated Carbon	• Chemical packages; scale inhibitors to hinder particulate formation, chemicals used vary with salinity • Precipitates iron, kills bacteria and destroys polymers • Removes scale particles • Remove multi-valent ions and some soluble organics
Bacterial Imbibition / Removal	• Biocide Addition • UV Light Treatment • Oxidation: Ozone, Chloro compounds	• Inhibit, destroy sulfate reducers, etc., during treatment and down hole • Destroy bacteria after particulate removal • Kill bacteria, destroy polymers, oxidize iron
Desalination	• Ion Exchange • Reverse / Forward Osmosis • Thermal Treatment: Vapor Recompression	• Low salinities to 10,000 ppm, removes ions • Low salinities to 40,000 ppm, removes TDS, sensitive • High salinities (50,000 – 200,000 ppm), yields clean water

The treatment technologies and processes listed above are in widespread commercial use by operators. Numerous other treatment technologies are in development, with limited application, or used in conjunction with the listed technologies. Detailed assessments of most treatment technologies commonly in use are provided in a study conducted by the Colorado School of Mines.[88]

The following is a brief description of some common water treatment processes. They can be used either by themselves or in combination with each other. Many vendors combine the processes in different ways to achieve the water quality desired.

5.2 Water Treatment Processes

5.2.1 Settling and Dilution

Settling and Dilution are the easiest and least expensive of the produced water treatment processes. Settling is the simple removal of suspended solids using gravity in a large, lined pit. The pit has to provide sufficient residence time for the solids to settle. Dilution can be done while pumping the produced water to the fracturing job by merging flow from a produced water source and a fresh water source. The salinity in the combined stream is controlled by the amount of fresh water added to the produced water.

5.2.2 Filtration

There are many different types of filtration systems including sock, sand, carbon, glass and diatomaceous earth. For filtering fracturing water while it is being pumped, the sock filter is the most common. A 25-micron filter is used for most fracturing jobs. Most of these filter systems are highly mobile and can operate at 100 barrels per minute.

5.2.3 Thermal Evaporation/Distillation: Thermal Vapor Compression and Mechanical Vapor Recompression

Distillation can be done with either small mobile units or large stationary units. The distillation process can be used with water up to 300,000 parts per million (ppm) TDS and can remove particles as small as one micron. The distillation process has the highest energy consumption of any of the water treatment technologies used. Distillation can process wastewater to meet or exceed environmental discharge water quality standards that are currently in place.

In general terms, distillation involves boiling water into steam, which is then passed through a cooling chamber and subsequently condensed into a purified form. This process is used to segregate water impurities from the purified product for collection and disposal. More modern approaches for the distillation process include the use of Thermal Vapor Recompression (TVR) and Mechanical Vapor Recompression (MVR). In principle, both technologies distill water in a similar overall process but differ in how increases to steam pressure and temperatures are applied.[89] With TVR, steam jet ejectors are used to raise the pressure and temperature of vapors, whereas, with MVR, a mechanical compressor is used instead of steam jet ejectors.

Thermal evaporation distillation is most effective at desalinating brine, and removing inorganic compounds such as heavy metals (iron, barium and lead) and nitrate, TDS, and hardness (calcium and magnesium). In some cases thermal evaporation distillation can be effective at the removal of organic material such as bacteria, through the boiling process. When using MVR, the treatment of raw water (or brine) with TDS concentrations of 60,000-80,000 milligrams per liter (mg/L) will result in fresh water recovery rates of approximately 70%-85%.[90] Evaporators are capable of treating produced water with higher TDS concentrations, but levels above 80,000 mg/L result in loss of water recovery (or increased brine concentrate) and an increase to treatment costs due to the additional energy required for treatment. In general, MVR systems are limited to treating water with TDS concentrations of 150,000 mg/L with a water recovery rate of approximately 50%.[91] Problems associated with this technology include fouling with organic deposits and corrosion within the heat exchanger that is caused by the recirculation of brine, which is used for heat recovery in the evaporator.

5.2.4 Chemical Treatment

The addition of chemicals to promote agglomeration (flocculation) of polymers (friction reducers or scale inhibitors) and suspended solids is typically one of the early treatment steps before produced water is migrated to other treatment processes when, for instance, disposal or beneficial reuse options are being considered. In addition, water used for drilling or fracturing may come from several sources, including freshwater supply wells, chlorinated city water, rainwater, pond water, and lake water; each of which contain some bacterial content.[92] For example, chemical treatment of source or recycled water that is being used for fracturing purposes may require the addition of biocides to reduce bacteria in drilling equipment, which if left untreated, may lead to fouling.

Flocculation (i.e., the adhesion of smaller particles to form large particles through aggregation) is used prior to evaporation or membrane treatment technologies to minimize the effects of scaling, or to reduce the build-up of polymers when the objectives of water treatment are for fracturing reuse. The process of flocculation allows particles to be more easily retained and removed as solids in the form of a “filter cake” or sludge. In general terms, the agglomeration of particles (flocs) facilitates separation of solid particles from their suspension liquid by means of sedimentation which in turn allows the solid phase to be removed in a minimal volume via filtration. The three main types of chemicals used in the flocculation process are inorganic electrolytes such as aluminum (aluminum sulphate), lime, ferric chloride, and ferrous sulfate; organic polymers; and synthetic polyelectrolytes with anionic or cationic functional groups. The water can then be run through a dissolved air filtration (DAF) unit or clarifier to remove the floating solids and those that sink to the bottom of the tank. The sludge recovered from the DAF or clarifier can then be dewatered, tested, and if compatible, disposed of in a land fill.[93]

In the oil and gas industry, it is common practice for untreated produced waters to be placed in open impoundments while awaiting use in the fracturing process. Microbes that can cause problems with equipment can grow under these conditions. Biocides are added to drilling and fracturing fluids to prevent micro-organism growth on associated equipment, as well as to reduce bio-fouling of fractures.

5.2.5 Electro Coagulation

The electro coagulation process uses either steel or aluminum electrodes and an electric current to remove oil, suspended solids and heavy metals from produced water. It can treat water with up to 300,000 TDS. Electro coagulation has become a rapidly growing area of wastewater treatment due to its ability to remove contaminants that are generally more difficult to remove by filtration or chemical treatment systems, such as emulsified oil, total petroleum hydrocarbons, suspended solids, and heavy metals. As water passes through the electro coagulation cell, multiple reactions take place simultaneously. As the reactions continue, large flocs form that entrain suspended solids, heavy metals, emulsified oils and other contaminants. Finally, the flocs are removed from the water in downstream solids separation and filtration process steps.

5.2.6 Reverse Osmosis

Reverse Osmosis (RO) is a water treatment technology using semipermeable membranes to remove salt and other constituents from water. Pretreatment of the water prior to the RO membrane is essential to minimize the effects of fouling which can greatly reduce the efficiency of the separation and prevent damage to the membrane. Types of pre-treatment are dependent on the quality of the water processed. Energy is the single largest cost to processing water using RO. One of the biggest drawbacks to using RO is the limited amount of useable water recovered. Depending on the salinity of the water being treated, 50% or more of the treated water could end up as heavy brine. In many cases, the heavy brine is a waste product and has to be disposed of.

When two solutions of different concentrations are placed between semi-permeable membranes, the solvent will pass from the less concentrated to the more concentrated solution. This flow produces a pressure difference which is referred to as osmotic pressure. If these pressures are reversed by applying energy from a pump, pure water is forced from the more concentrated solution through the membrane into the less concentrated solution. As the pressure increases, the concentration of solution passing along the membrane is also increased. The subsequent buildup of dissolved solids along the membrane requires continual increases in energy (between 140 and 400 pounds per square inch [psi]) to pass the pure water through the membrane.

RO is subject to fouling if pretreatment methods are not used. Pretreatment requirements include the removal of suspended solids to prevent colloidal and bio-fouling, as well as the removal of dissolved solids to prevent scaling and chemical attack. Pretreatment can include media filters to remove suspended particles, ion exchange softening or anti-scalant to remove hardness, temperature and pH adjustment to lower chemical solubilities to prevent scaling, activated carbon or bisulfite to remove chlorides, and cartridge (micro) filters to remove some dissolved particles and any remaining suspended particles. In addition, RO water treatment systems may utilize a crossflow process to keep the membrane clear. In the crossflow process flow of water is reversed momentarily to push sediment and scaling off the screen, or an acid wash may be used on thicker membranes.[94]

RO water treatment can be applied to convert brackish water, seawater or brine to drinking water; reclaim wastewater; and recover dissolved salts from various industrial processes. RO can treat water with TDS concentrations up to 40,000 mg/L but is not effective at treating non-ionized materials such as gases or large organic molecules that will not pass through the membrane. Relative to distillation, the RO treatment produces lower water recovery rates (approximately 65%) or a larger brine stream, which will increase disposal costs.[95] However, RO water treatment requires less energy than thermal distillation treatment, which may help to lower operating costs. In addition, an advantage of reverse osmosis over evaporation is that the lifecycle costs of RO are about half those of evaporators.

5.2.7 Ion Exchange

Ion exchange involves the exchange or replacement of dissolved constituents by attachment to electrostatically charged ion exchange material, often consisting of a synthetic resin. The process uses an exchange of ions between a solid resin and the water. Prior to running through the ion exchange resin, the water must be pretreated to prevent fouling the resin. Ion exchange resins are classified as cation exchangers, which exchange positively charged ions, and anion exchangers, which exchange negatively charged ions. Ion exchange is a reversible chemical reaction wherein positively or negatively charged ions present in the water are replaced by similarly charged ions present on the surface of the resin. The resins are either naturally occurring inorganic zeolites or synthetically produced organic resins. When the replacement ions on the resin are exhausted, the resin must be recharged with more replacement ions. The ion exchange process relies on the natural tendency of water solutions to be electrically neutral. Therefore, ions in the resin bed are exchanged with ions of similar charge from the source water and as result of the exchange process, no reduction in ions is obtained.[96]

The process of ion exchange historically has been used to remove hardness ions such as calcium and magnesium by replacing them with sodium and chloride ions.[97] However, in the case of oil and gas produced water, ion exchange is typically used to preferentially remove sodium. For oil and gas-produced water, ion exchange is used to deionize water by replacing ions, such as conductive salts (desalination), with H+ and OH- when pure water is required.[98] However, ion exchange has limited applicability as a primary treatment method in the shale gas industry since the technology is limited to removing constituents in waters with TDS levels below approximately 5,000 mg/L, but is applicable as a pretreatment method to remove other water constituents such as heavy metals (i.e., barium, iron, strontium) and alkalinity or as a polishing treatment.[99]

5.2.8 Electrodialysis and Electrodialysis Reversal

Traditionally, electrodialysis treatment of water has been used to desalt brackish water to produce higher quality water. The basic principles of this treatment process are similar to ion exchange in that dissolved ions present in water have either a positive or negative charge and are attracted to electrodes with an opposite electric charge. In electrodialysis, membranes that allow either cations or anions (but not both) to pass are placed between a pair of electrodes. These membranes are arranged alternatively (cation and anion) to selectively collect charged ions and a spacer sheet that permits feed water to flow along the face of the membrane is placed between each pair of membranes. Positively charged ions (e.g., Na^+) migrate to the cathode and negatively charged ions (e.g., Cl^-) migrate to the anode. During migration the charged ions are rejected by similarly charged ion exchange membranes. As a result, water within one compartment is concentrated, leaving desalted water within another compartment of the electrodialysis unit.

An improvement to electrodialysis, referred to as Electrodialysis Reversal (EDR), utilizes the same concept except that in EDR, there is periodic automatic reversal of polarity and cell function to reverse the flow of ions across the membrane. The reversal process is useful in breaking up and flushing scales, slimes, and other deposits in the cells before they build up and create flow problems across the cells. The flushing allows the unit to operate with fewer pretreatment chemicals, which helps to minimize membrane fouling.[100]

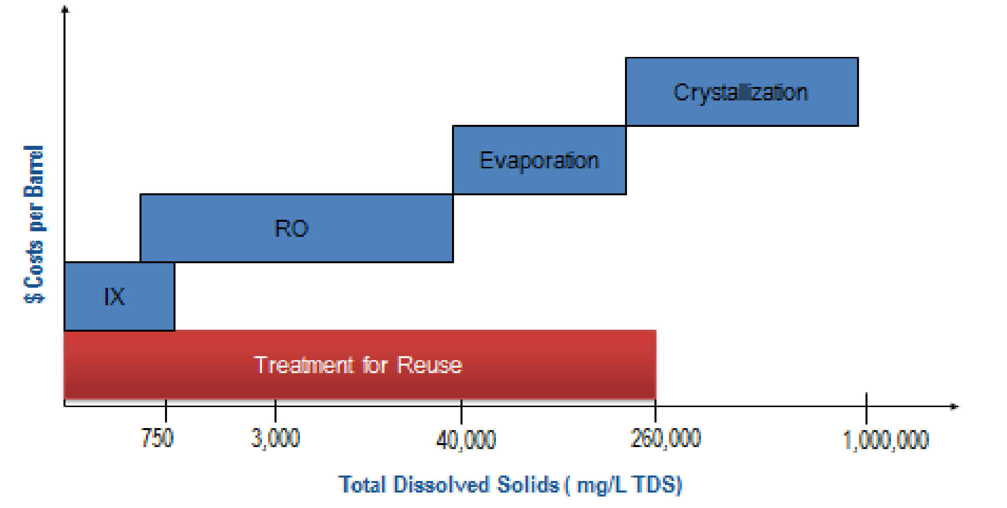
Electrodialysis and EDR differ from a normal ion exchange process by utilizing both cation and anion selective membranes to segregate charged ions extracted from a water solution.[101] Depending on the number of stages present within an electrodialysis unit, this treatment process can remove approximately 25% to 60% of TDS, with a resulting waste stream of approximately 15% to 30% of the raw water input. The number of stages required for the electrodialysis process is driven by feed water quality and the economics of achieving the desired outcome quality. Primary factors that impact feed water quality are hardness, alkalinity, TDS, temperature, and the presence of ions, such as iron and manganese. Electrodialysis is limited to treating TDS concentrations ranging from 4,000 mg/L to 15,000 mg/L.[102]

In general, electrodialysis is more expensive than RO but is more resistant to membrane fouling,[103] which in turn can reduce costs typically associated with membrane replacement or cleaning. The electrodialysis treatment process is applicable for removing and/or reducing aluminum, barium, bromide, cadmium, calcium, chloride, 97%-98% of copper, 90%-95% of cyanide, 94%-97% of potassium, TDS, and volatile organic compounds (VOCs). Electrodialysis does not remove bacteria, colloidal material, or silica. Electrodialysis and EDR do not remove small suspended material, so 5 to 25 micron polishing filters immediately before the feed inlet are necessary. Pre-treatment is also necessary for electrodialysis to control scale build-up of calcium carbonate

($CaCO_3$) and magnesium hydroxide, as well as iron ions. Typically, these constituents are controlled either chemically by acid addition for pH adjustment and/or by cartridge filter.

The following graph in **Exhibit 43** is a qualitative representation of the relative costs of several of these treatment options along with the range of TDS in the water that can be treated by each technology.

EXHIBIT 43: RANGE OF APPLICABILITY VS. COSTS



5.3 Recycling Water for Non-Oil and Gas Uses

Produced water and flowback water can be recycled for other, non-oil and gas uses as well, after treatment. This again has the benefit of reducing the demand for fresh water in these applications.

5.3.1 Agricultural Use

Produced water can be used for agricultural livestock and irrigation applications, depending on the quality of the water available for use. These applications are generally most desirable in arid regions. An increase in available water for agricultural livestock can result in increased cattle density, increased weight gain in cattle, and a subsequent increase in range utilization. Incorporating stock water use in a produced water management plan can be a viable component, but stock ponds should be limited by the volume of water the system can handle without creating overflow channels that could impact downstream properties. As a result, stock water is generally used in concert with additional management options. Produced water availability increases the opportunities for farming through irrigation, especially in areas with limited water resources. Regions historically limited to dry land farming could incorporate forms of irrigation to grow additional higher-water-needs crops. The suitability of produced water for irrigation purposes is limited by the water quality, and the physical and chemical properties of the soils to be irrigated. Furthermore, it is limited by landowner commitment to the additional management actions related to addressing the use of poorer water quality and potential regulatory constraints.

5.3.2 Industrial Use

A variety of existing industries could benefit from the increased water supply from oil and gas produced water, including coal mines, animal feeding operations, cooling tower water for various industrial applications, car wash facilities, commercial fisheries, enhanced oil recovery, and fire protection.

In coal operations, produced water is primarily useful for dust suppression operations and restoration efforts including recharging depleted groundwater aquifers and irrigation for surface revegetation. Use of produced water for coal operations could reduce the impact on both groundwater and surface water supplies that would otherwise be used to maintain operations. Coal mine use is limited primarily by timing, as water availability for restoration and recharge must coincide with water demand, and transportation.

Many industrial activities, such as chemical plants and power plants, require water as a cooling agent. Also, coal-fired power plants and coal-to-liquids plants require large volumes of water to sustain operations. Many proposed coal-to-liquids operations could become realities with the available produced water for potential use. Water quality is a hindering factor, as high TDS waters can cause mineral deposits in a closed system, reducing flow and heat exchange. Therefore, the water must be treated to the required quality.

Field and car wash facilities have become more prevalent as the awareness of noxious weed spreading increases. Spreading of noxious weeds can make any site restoration more complicated as well as negatively impacting ecosystems, farmland and grazing land. Using oil and gas produced water to wash equipment and vehicles before and after entering areas with high probability of transporting noxious weeds can significantly reduce the potential distribution to other areas. Field washing facilities are typically installed as part of restoration projects and, therefore, are short term. However, applicability is limited by produced water quality.

Enhanced Oil Recovery (EOR) is another common produced water management option which involves injecting produced water into a secondary or advanced recovery well into conventional oil-producing horizons. The injected fluid creates a waterflood that sweeps the oil towards production wells strategically located throughout a mature field. This process is fairly common in oil and gas operations and can be effectively implemented with varying degrees of water quality. Unlike other beneficial uses, water quality limits this option in the other direction; high-quality produced water would be better suited for other beneficial uses. This process is typically constrained by both transportation and water volumes available.

Produced water availability would have to be in the near vicinity of mature conventional oil development to make the beneficial use economically viable. Furthermore, large volumes of water are necessary to implement secondary or enhanced oil recovery operations, making the demand for water long term; in some situations, supplemental water sources may be necessary.

Fire protection and fighting fires does not require the high-quality water and produced water could supply both fire hydrants and sprinkler systems, reducing the strain on drinking quality water traditionally obtained from municipal supply systems.

5.4 Non-Discharge Options

Where any discharge of produced or treated water is a major concern, options that result in zero discharge of water can allow hydraulic fracturing to take place while addressing those concerns.

5.4.1 Evaporation ponds

Evaporation ponds are designed to store water at the surface so that natural evaporative processes can move the water from the land to the atmosphere. As the evaporation process occurs, pure water is removed, leaving behind increased TDS water which over time can become concentrated brine. Evaporation pits are lined to prevent infiltration of the water. Use of evaporation ponds is most suited for arid areas with high natural evaporation rates. Reduced evaporation rates can occur as a result of landscape and topographical variations, landowner constraints, natural runoff or flooding, and seasonal variations. In areas of shale gas development, evaporation pits are not a likely beneficial use alternative primarily because high salinity waters, such as produced water, have low evaporation rates. Furthermore, in areas such as the Marcellus and Utica play, precipitation far exceeds the amount of evaporation that will occur.

5.4.2 Crystallization

Crystallization is an equilibrium-based separation technology that uses energy as the separating agent and is often comprised of a combination of treatment processes that are more energy efficient at removing water from lower TDS waters.[104] RO is commonly used for an initial pass through if TDS levels are sufficiently low. Crystallization processes can then be used to further concentrate the RO concentrate stream by extracting water from the brine solution. Total volume of the liquid concentrate is reduced while the associated TDS increases significantly. The water (extract phase) can be recirculated through the RO and concentrate (sludge-water) flows through evaporators. Water is evaporated with heat or pressure differential and the dissolved solids remain in sludge state. Handling and disposal of reduced volume of waste in slurry/sludge form is easier.

Salt is extracted from brine (salt solution) by evaporating away the water. Usually an industrial site for salt production would contain a series of evaporators through which the brine becomes progressively more concentrated. Each evaporator contains a large number of tubes through which the brine is circulated. The tubes are heated by steam and the large number of tubes gives a large surface area for heat transfer to the brine. As the brine boils, salt crystals begin to form and sink to the bottom of the evaporator. This produces a thick mixture of salt crystals and salt solution, which is fed into another evaporator to repeat the process and concentrate the salt further. The process can have several stages to concentrate the slurry. In commercial salt applications the slurry can be centrifuged to dry for industrial use or heat dried for human or food grade use.[105] For crystallization to occur from a solution it must be supersaturated; this means that the solution has to contain more solute entities (molecules or ions) dissolved than the solution would contain under the equilibrium (saturated solution) state. Supersaturation can be achieved by various methods. The most common ones in industrial practice are 1) solution cooling, 2) addition of a second solvent to reduce the solubility of the solute (technique known as antisolvent or drown-out), 3) chemical reaction, and 4) change in pH.

Crystallization is often used to process the concentrate from Reverse Osmosis and Electrodialysis from low TDS water. Evaporators can treat RO or Electrodialysis concentrates to a total solids (TS) concentration of 300,000 ppm, subject to some solubility limitations. The sludge or solid can then be used commercially, as in salt production, or disposed of properly resulting in a zero liquid discharge system.

Exhibit 44 summarizes the input and output water quality and other characteristics of the water treatment technologies discussed above.[106]

EXHIBIT 44: SELECTED FEATURES OF WATER TREATMENT TECHNOLOGIES

Treatment Technology	Feed Water Quality	Output Water Quality	Infrastructure Considerations	Pretreatment Needs
Settling and Dilution	No restrictions	Depends on system design	Large footprint required	None
Filtration	All TDS levels	> 90% oil and grease removal	Requires a vessel to contain the media and pumps and plumbing to implement backwashes	None
Thermal Distillation	Applicable to a wide TDS range	Very high quality	Large physical plant size.	Feed water requires screens and rough filtration to remove large suspended solids
Chemical Treatment	Applicable to all TDS levels	Depends on the process	Depends on the process	None
Reverse Osmosis	Most applicable for TDS ranging from 20,000 to 47,000 mg/L	Typically, product water TDS ranges from 100 to 400 mg/L	Requires minimal operational footprints	Requires extensive pretreatment to mitigate harmful water quality constituents that will otherwise foul or scale the membrane
Ion Exchange	Average TDS application range is between 500 mg/L and 7,000 mg/L	Dependent on feed water salinity and operating conditions	Highly variable operational footprint depending on the application	Requires pretreatment options including suspended solids, oxidized metals, and scaling mineral removal
Electrodialysis	Cost effective to TDS < 8,000 mg/L	Product water quality depends on ED stages, can achieve over 90%	No special infrastructure requirement	Requires removal of particles and other scaling and fouling substances through filtration, pH adjustment, and addition of antiscalant
Evaporation Ponds	2,000 mg/L to high TDS >40,000 mg/L	N/A	Large land area required	None
Crystallization	Not sensitive to the level and type of brine	No product water	No special infrastructural requirement	May include settling and filtration to remove suspended solids and organic matter

6 Conclusions

In conclusion the development of hydrocarbon resources in the APE of the DRB would be limited to a six county area in the Upper Region where thermally mature Marcellus and Utica shales would most likely produce dry gas; there are an estimate 201 square miles or 128,640 acres available for development under the old Article 7 rules without restriction; the reasonably expected development rate would be approximately 40 wells per year; current hydrologic conditions in the Upper Region of the DRB have been strained due to reduced annual precipitation for the past few years; the water withdrawn for HVHF in the APE is estimated at ~447 Mgals annually or 1.22 Mgal/d representing only 2.23% of the current estimated USGS daily withdrawal for the APE or only 0.81% of the DRBC reported withdrawals for the Upper Region; the compliance violations in Susquehanna County over the past 5-years indicate that 3.63 release events might occur per year in the APE and there is less than a 0.5% chance that one of those events would potentially reach the Waters of the Commonwealth; the landscape disturbances associated with pad development would range from 400 to 200 acres (0.625 – 0.31 sq. miles) over the 10-year development period following restoration activities; state and private revenues generated by the development of natural gas would be significant with estimates ranging from $148 million to $475 million annually; and water treatment technologies are available that would reduce withdrawals, recycle produced water, and eliminate discharges.

The analysis presented in this report demonstrates that the potential risks to the environment posed by unconventional gas development are controllable and negligible and are offset by considerable potential benefits, and that a prohibition of HVHF in the DRB is not justified. The reasonable rate of development estimated, the focus on dry gas, the anticipated small surface footprint, the comparatively minor amount of water that would be withdrawn, the advances in pad containment and spill management that industry has made, and the projected economic benefits of unconventional gas development all lead to this logical conclusion. Furthermore, given the exceptionally low number of violations in nearby Susquehanna County over a period that saw nearly four times as much drilling activity as is anticipated for the APE, as well as the water treatment technologies available for recycling and zero discharge that are protective of the environment, the DRBC should reconsider its proposed regulations regarding oil and gas development in order to better balance the risks and benefits of such development in accordance with the DRBC Comprehensive Plan.

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