HydroQuest

HydroQuest
P.O. Box 387
Stone Ridge,
NY, 12484
845-657-8111
URL: hydroquest.com
hydroquest@yahoo.com

<u>Report for the Delaware River Basin Commission</u>
<u>on</u>
<u>Natural Gas Development Regulations</u>
<u>December 9, 2010</u>
<u>Article 7 of Part III – Basin Regulations</u>

<u>To</u>
<u>Delaware Riverkeeper Network</u>

Prepared by
Paul A. Rubin
HydroQuest
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Executive Summary

Consideration of permitting and regulation of gas drilling in the Delaware River Basin (DRB), as well as elsewhere in the world, must be weighed against the long-term best interests of the population. Draft Delaware River Basin Commission (DRBC) regulations do not adequately address the short and long-term hydrogeologic picture and, as such will not adequately "*protect the water resources of the DRB … to meet present and future needs.*" Water quality protection requires regulatory management that takes into account the slow rate of groundwater flow and the useful life of aquifers that will be required by future generations. Groundwater that comprises DRB freshwater aquifers eventually surfaces as the base flow of the Delaware River and all its tributaries. The rate of groundwater flow, along with contaminants in it, is relatively slow, typically taking many years, decades or longer to reach distant wells and streams. This time frame contrasts sharply with both the approximately 4 to 20 year productive life of gas wells and, importantly, the short-term time frame of fiscal and water quality responsibility contemplated by the DRBC draft regulations. The best interests of people using the potable water of the DRB lies in assiduously protecting surface and groundwater quality for the effective life of the aquifer.

The DRBC must plan to protect the water resources of the Basin in perpetuity. This requires looking beyond short-term impacts and necessitates planning for problems that may not occur until 100 years from now or more. As the DRBC plans for the 100-year flood, so too must the DRBC plan for the 100-year break-down of well cement and casing. Changes in geology are measured over centuries and longer. Thus, regulations of intentional geological disturbances – such as deep drilling and hydro-fracturing -- must look centuries and longer into the future. Protection of the high water quality of the Basin is not likely to be achieved under the DRBC regulatory framework as drafted because the technology (i.e., effective zonal isolation materials)

required for "long-term isolation" of freshwater aquifers via existing well completion and cementing methods is not sufficiently developed to withstand stresses of the downhole environment. Drilling regulations must insure that surface water and freshwater aquifers will be protected for hundreds of thousands of years, or more.

The useful life of DRB aquifers is measured in geologic time. It is a function of natural erosive processes that, if left unaltered by humans, will provide safe drinking water for the next one million plus years. Boreholes advanced for gas exploitation breach key geologic confining beds that formed over millions of years and naturally separate deep saline waters from overlying freshwater aquifers. While the gas industry is actively researching and advancing concrete formulations to seal deep chemical-rich horizons from freshwater aquifers, the life of concrete subjected to harsh downhole conditions is probably less than 100 years - only about 0.01 percent of the life of Basin aquifers. Concrete failure mechanisms are many, including corrosion, shrinking, cracking, debonding, poor concrete blends, and micro-annulus formation. Failure of concrete sheaths and plugs will allow commingling of connate and freshwaters, as well as contaminating radioactive and methane gases and Light Non-Aqueous Phase Liquids via open borehole pathways. Beyond this, repeated hydraulic fracturing is likely to open and/or create joint and fault pathways between the same horizons that were formerly isolated. Corrosion of steel casings in harsh downhole conditions will, like cement, lead to failure in less than 100 years. Although it may be possible to physically isolate geologic horizons interconnected by wellbores, once fracture pathways are open, aquifer degradation is assured and cannot be remediated. Physical evidence from assorted gas field locations around the world, including Dimock, PA, indicate that aquifer contamination has already occurred as a result of natural gas extraction through hydrofracturing and will only become more and more widespread as hydrofracturing is used more widely.

Aquifer contamination, possibly from thousands of gas wells, is insidious in nature. It is far worse than toxic waste dumps such as Love Canal or the Cortese Landfill because it is not areally limited, contaminant plumes are deep below the ground surface, the natural physical isolation of aquifers will have been destroyed by drilling activities, and aquifer restoration will almost certainly be impossible. Beyond this, the DRB is in a seismically active region susceptible to earthquakes of magnitude 6 or greater that have a high recurrence probability. Earthquakes may catastrophically and instantly shear thousands of well casings, cause cement sheaths to fail, and may allow commingling of formation waters - resulting in irreparable and permanent harm to freshwater aquifers. The earthquake history of the DRB is well documented.

Prior to promulgation of gas drilling regulations, it is first necessary to thoroughly evaluate the hydrogeologic, seismic, and environmental issues raised in this report in a broad environmental impact statement and public hearing format. It would be prudent to adopt a moratorium on all drilling activities until after this is complete. The risk to DRB water quality is too great to fail to adopt a moratorium and undertake a comprehensive environmental analysis. Furthermore, as written, the draft regulations do not adequately address the long-term liability associated with failed and failing gas wells. The regulations should be amended so that the DRBC and its officers, as the DRB's permitting and regulating body, become legally and financially responsible for all long-term aquifer and stream degradation immediately following their release of project sponsor liability.

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Figures: (Also available for viewing/download at http://hydroquest.com/DRBCfigures/)

Introduction

On behalf of Delaware Riverkeeper Network, I have reviewed the draft Delaware River Basin Commission Natural Gas Development Regulations dated December 9, 2010, which would add Article 7 to Part III – Basin Regulations of the DRBC Water Quality Regulations, as they relate to the practice of developing gas wells in shales. Much of my focus in this report relates to the Appalachian Basin that encompasses portions of New York, Pennsylvania, New Jersey, and Delaware.

My comments relate to the potential degradation of freshwater and groundwater resources stemming from inadequacies within the DRBC draft regulations and concern that so-called "state-of-the-art" plugging and abandonment (P&A) practices and materials are not sufficiently advanced to insure long-term isolation between saline and freshwater zones. The draft DRBC regulations do not adequately address the short and long-term hydrogeologic picture and, as such, will not adequately "*protect the water resources of the DRB … to meet present and future needs*" **(Section 7.1 (a)(e)).**

Based on a review of industry, scientific and other literature, it is clear that many well cement plugs and surface casings will almost certainly degrade in less than 100 years – after which time thousands of open hydraulic pathways will result in commingling of deep gaseous, saline, waters and freshwater aquifers on a broad scale. It is important that the DRBC gas drilling regulations do not inadvertently leave behind a legacy of forever degraded freshwater aquifers. The implications of short-term cement failure on long-term aquifer water quality protection are extremely significant. The environmental ramifications of this situation rival the shorter term release of radioactive contaminants to our waterways as recently documented in the New York Times by Ian Urbina. In my professional opinion, it is not prudent to finalize drilling regulations in advance of significant scientific assessment of issues raised in this report (i.e., long-term cement and casing integrity and seismic risk).

I offer this opinion based on my training as a geologist, hydrogeologist, and hydrologist with more than twenty-nine years of professional environmental experience, which includes work conducted for the New York State Attorney General's Office (Environmental Protection Bureau), Oak Ridge National Laboratory (Environmental Sciences Division), the New York City Department of Environmental Protection, and as an independent environmental consultant as President of HydroQuest. My educational background and professional experience are more fully set forth in my Curriculum Vitae, attached as Addendum 1 to this report. I have conducted detailed assessments of streams, wetlands, watersheds, and aquifers for professional characterizations, for clients, and as part of my own personal research. I have authored numerous reports and affidavits related to this work and have made presentations to judges and juries. In addition, I have published papers and led all day field trips relating to this work at professional conferences. I have also authored extensive comments relating to exploratory wells in the Delaware River Basin, as well other material related to gas drilling and hydraulic fracturing. The opinions expressed in this report are stated to a reasonable degree of professional certainty.

Draft DRBC Regulation Features of Concern

The draft DRBC regulations contain a number of features, assumptions, and omissions that, if these regulations are promulgated, may result in deleterious impacts to the quality and hydrologic integrity of freshwater aquifers. Many that are detailed in bullet format below require additional clarification or modification before regulations are finalized. A number of these and other regulation items are discussed in detail in this report, along with supporting documentation.

- The financial assurance obligation of a project sponsor may expire within a few years if so determined by the Executive Director. As discussed below, the financial obligation of a project sponsor relative to the long-term protection of aquifers should be extended far into the future, even after gas production ceases.

- The financial assurance of $125,000 required per gas well is very low **[Section 7.3(k)(8)]** and may be reduced by 75% after one year **[Section 7.3(k)(15)]** if no harm to water resources is known. Because hydrofracking may occur many times over the life of a well, groundwater moves very slowly, and contaminant impacts may not be known for decades, this amount should be substantially increased along with the liability time period. Consideration should be given to increasing the financial assurance of each horizontal projection by 75% for each new hydrofracking event.

- A maximum future harm monetary amount of $25 million for all project sponsors within the Delaware River Basin is extremely low **[Section 7.3(k)(16)(i)].** A protective fund somewhat akin to that imposed on British Petroleum relative to its Deepwater Horizon/Macondo Well blowout and the resulting Gulf of Mexico oil spill should replace this limited fee.

- The draft regulations do not allow site access without prior notification **[Section 7.3-(j)]** Site Access). Site access by authorized representatives of the Commission should be at any time, without any prior notification.

- Based on discussion presented later in this report that provides evidence that fractures extend beneath surface valleys and to distances of at least 2,000 feet, the regulations should prohibit gas well projections within a minimum of 2,000 feet from all surface water supply intakes, reservoirs, lakes, wetlands, major streams, and rivers and expressly prohibit drilling and hydraulic fracturing under water bodies (see Bedrock Fracture Connectivity, Pressure Waves and Setbacks report section). Upward escaping methane and other contaminants that leak into these water bodies may irreparably harm them.

- The regulations assume that plugging and abandonment (P&A) material and technology are capable of isolating zones forever. As discussed in this report, this is not the case. Detailed P&A regulations are needed. This topic area is of extreme importance and warrants extensive additional analysis in both an Environmental Impact Statement and Public Hearing format. Because hydrofracking opens joints well beyond the borehole, P&A may do little to protect the environment after chemical additives are repeatedly injected into bedrock formations under high pressure.

- The regulations should be amended to require sophisticated assessment of well conditions such that cement mixtures and additives or new materials are optimized for effective zonal isolation in each well. Cement mixtures and sealants should be required to conform with state-of-the-art self-healing mixtures similar to FUTUR cement that has the ability to react to and repair channels though which hydrocarbon-rich fluids and gases may otherwise migrate. Bellabarba et al. (2008), for example, provide an excellent discussion of the type of well analyses and cement integrity monitoring that should be conducted as standard operating practice throughout the Delaware River Basin. Prior to amending the regulations to best achieve zonal isolation, the technology and methods used in constructing underground gas-storage wells should be fully assessed and considered for maximum protection of freshwater aquifers. In light of the many cement failure mechanisms discussed in this report, gas well installations should be required to use the best available materials and technology.

- The regulations permit the Executive Director to reach settlement in contamination cases without restoring aquifer waters or providing suitable alternate water supplies. The regulations should be rewritten to always require full aquifer contaminant plume assessment and remediation for each gas well related contaminant excursion. Beyond this, if aquifer remediation is not capable of restoring aquifer water quality for private use <u>without</u> filtration equipment, then the offending gas company should be made responsible for the study, design, installation, maintenance, and long-term operation of an alternate water supply system.

- The regulations do not require project sponsors to assess individual watershed and aquifer boundaries relative to their horizontal well projections in an effort to reduce shifting pollution from one medium to another **[Section 7.1(e)(2)(iv)].** The regulations should be modified to preclude project sponsors from potentially compromising groundwater quality in multiple watersheds by extending horizontal projections under watershed divides. This may first require hydrogeologic assessment of both shallow and deep groundwater flow systems.

- Well spacing requirements should be made consistent between all states in the Delaware River Basin. Current well spacing requirements in host states need to be re-evaluated based on the DRBC's requirement to protect sensitive Delaware River Watershed features. Pennsylvania has no codified spacing requirements and New York's requirements are not based on the need to protect Special Protection Waters and allow for infilling and other alterations that violate the original intent of spacing limits.

- Pre-alteration baseline groundwater flow and homeowner water chemistry maps are not required over and outward from all horizontal projections. They should be. The regulations should be amended to require that all homeowner wells within a distance of 2,000 feet beyond the outer boundary of wellhead horizontal projection arrays be sampled prior to drilling and tested to establish baseline water quality according to accepted EPA methods. The regulations should specifically list all chemical parameters, test methods, and method detection limits that apply. In addition, baseline testing and analysis should be conducted for sponsor-specific tracers. Indicator chemical parameters should be assessed and selected. These might include gas company specific chemical tracers; methane, radium, total organic carbon; assorted hydrocarbons including benzene, toluene, and xylene; chloride; LNAPLs used in hydrofracking fluids, and other chemicals. Residential well sampling and analysis for all parameters must be completed each year during operation and for ten years thereafter.

- The draft regulations do not provide an adequate basis to compare pre- and post gas well development impacts on river, stream, and spring water quality. The regulations should be revised to make the gas industry financially responsible for enhanced chemical and biological monitoring in waterways proximal to their operations. Because ecosystem and ecological impacts may be cumulative in nature, it is necessary to monitor cumulative chemical buildup and impacts on a regular basis. This should be approached in a three prong manner to assess 1) potential chemical buildup in sediments, 2) bioaccumulation in indicator species, plus macro-invertebrate analyses, and 3) contaminant loads in flowing water. Calculation and assessment of contaminant loads requires both chemical data and stream flow data. Often, chemical concentrations and loads increase coincident with increased stream flow (i.e., during storm or runoff events). An effective means of monitoring stream flow in watersheds with numerous gas wells is via installation, calibration, and maintenance of gaging stations (e.g., USGS) such as those used for this purpose throughout many of the New York City watersheds. The large scale of gas drilling and chemical use proposed throughout much of the Delaware River Basin warrants an expanded, and gas company-funded, water quality monitoring network, beyond that currently in place.

- The regulations do not address potential adverse air and water quality impacts to caves and mines used as bat hibernacula within the DRB. The potential buildup of methane and hydrocarbons within enclosed cave and mine environments may be lethal to bat populations, including the endangered Indiana bat (*Myotis sodalis*). It is recommended that the regulations be amended to include pre- and post drilling air and water quality monitoring in mines and caves in the watershed. Consideration should also be given to 1) preparing a location map of these features before regulations are promulgated, and 2) establishing a no drill buffer zone (inclusive of horizontal projections) that extends 2,000 feet outward from mapped cave and mine boundaries.

- Regulatory monitoring of non-gas wells is restricted to a set distance outward from vertical wellbores. Baseline and subsequent monitoring of homeowner well methane concentrations and selected chemical/water quality parameters should also be conducted at a minimum of 2,000 feet outward from the outer boundary of gas well arrays. The section below, "Additional Life of Concrete Material – Plus Life of Steel," provides documentation and justification for the 2,000 foot monitoring zone.

- While it is recognized that the Commission has "*authority to control future pollution that may injuriously affect the waters of the basin*," it is clear from comments provided previously (e.g, Rubin 2010; Bishop 2010) that there have not been sufficient technical analyses to conclude that advancing gas exploitation in the Delaware River Basin will not irreparably and forever degrade the quality of freshwater aquifers and their receiving streams (see **Section 7.1–(e)** Planning Framework). A full Environmental Impact Statement, Delaware River Watershed-specific cumulative impact study, and public hearings are needed prior to any promulgation of a regulatory regime permitting natural gas development in the DRB watershed.

- The regulations do not provide a means to identify project sponsor-specific contaminant excursions and adverse water quality impacts. The regulations should require the use of sponsor-specific groundwater tracers to be introduced with all downhole fluids, with pre- and post-drilling monitoring. The regulations should specify that full aquifer restoration and, if necessary, alternate water supply system installation and maintenance is the full responsibility of offending gas companies without temporal or spatial restrictions on such obligations.

- The regulations do not require project sponsors to conduct or report on downhole microseismic or other applicable technologic imaging method results that may indicate the presence of faults or joints that may extend upward above gas-bearing shales (e.g., fracture reorientation across thrust faults). The regulations should require this testing such that hydrofracking is avoided near faults and joints open to the ground surface.

- The regulations do not require detailed surficial fracture mapping in advance of well permitting. The use of soil gas surveys and other fracture mapping techniques (such as that used by Jacobi [2002]) could be used to locate fractures that are open to the ground surface that are actively releasing methane from gas shales at depth. Analyses of this nature could be used to reduce the risk of aquifer contamination by avoiding placement of horizontal projections through gas-emitting fracture zones.

- The regulations, as drafted, largely seek to permit gas wells and exploitation without preliminary assessment of seismic risk to well casings, downhole cement integrity, and freshwater aquifers. Seismic hazard analyses should be required before final regulations are promulgated. These analyses should estimate values of peak ground acceleration with return periods up to at least 10,000 years. They should also assess the risk to aquifers via sheared and failed boreholes.

- The cease operations enforcement authority of the Executive Director **[Section 7.3(n)]** is not sufficiently detailed. This authority should be made more comprehensive by including well-field cease operations criteria (e.g., sudden hydraulic or water quality response of homeowner wells to hydraulic fracturing operations that demonstrate a link between deep and shallow fracture systems; any contaminated homeowner wells within or near a well field; unchecked and spreading aquifer contamination that is not being actively investigated and remediated via systematic hydrogeologic investigation; sponsor-specific tracer detection in freshwater aquifers or surface water features; repeated buildup of sustained casing-head pressure (SCP) in gas wells; gaseous excursions to homeowner wells, homes, or outbuildings; gaseous excursions to land and surface waters; demonstrated water and/or air quality impact to caves and mines; destructive seismic activity within or near a well field; improperly maintained and/or leaking gas wells or spills, accidents, leaks, etc. related to gas wells, tanks, well infrastructure and related equipment; contaminated surface waters or surface water features (such as wetlands or vernal pools); presence of airborne contaminants that have or may adversely impact resident health or the environment (e.g., volatile organics); fish and other biota kills associated with gas field chemicals; too lengthy contaminant investigation and response time; resident health issues associated with gas field activities; sudden sickness and/or death of nearby homeowner animals, as well as other animal mortality (e.g., rabbits, deer, birds, frogs, fish); secret, non-disclosure, property buy-out, or settlement agreements between a project sponsor and private landowners that result in any lack of transparency regarding surface water, groundwater, and/or airborne contaminants and knowledge of their full environmental and health impacts).

- The regulations are too limited in scope, as they are largely oriented toward short-term gas well permit issuance rather than long-term water quality protection. The regulations must be reviewed not only for the details within them, but also for the broader assumptions and basin-specific factors that may place DRB water quality at risk (e.g., design life of concrete and casing used for zonal isolation, seismic risks). The regulations must be substantially revised to take into account the issues raised in this report, as well as those raised by others.

- Consideration should be given to modifying **Section 7.4(d)(iii)** to allow water use from outside the DRB if it can be demonstrated that the frack water to be used is distilled and contaminant free. For example, distilled water derived via processing similar to the FracPure water treatment process discussed by Ellis (2010) may substantially reduce the quantity of DRB water needed for hydrofracking operations.

- Additional detail should be incorporated into the hydrogeologic report required in **Section 7.4(e)(4)**. This should include a map depicting groundwater flow direction and continuance of aquifer recovery monitoring until at least 90 percent of the initial pre-pumping static water is achieved.

- The regulations should be amended to require a step-drawdown pumping test on the production well upon drilling completion to near the base of the freshwater aquifer, before the borehole is cased and grouted. Preferably, this test should be conducted prior to well pad construction. The step-drawdown test should be conducted for a minimum of 24-hours, at increasing, measured, discharges designed to significantly stress the aquifer but not dewater the well. Well discharge should be routed far from the pumping well to avoid recirculation of discharged groundwater. All homeowner wells within 2,000 feet of the planned production well, or further at the discretion of the DRBC, should be fitted with transducers and monitored. If a decrease in water level is measured in all homeowner wells being monitored, the test may be discontinued prior to 24 hours. <u>Because industry-wide zonal isolation materials have a design life of 100 years or less, any production well found to be hydraulically connected to homeowner wells should be promptly completed as a freshwater supply well suitable for future use by the property owner and their grandchildren.</u> Failure to assess hydraulic connectivity along fracture pathways will almost certainly lead to another Dimock-like contaminant situation, especially under pressurized hydrogeologic conditions. An alternate gas well location should then be selected and tested prior to well pad construction.

- Long-term zonal isolation has a far greater chance for success if the entire borehole is sealed with cement or alternate high-quality durable sealant material. The regulations should be amended to require continuous and complete plugging of the entire borehole from production zones to the ground surface.

- Drilling regulations should not be finalized before completion of an in-depth evaluation of seismic risks to casing and downhole cement sheath integrity (i.e., seismic risk assessment).

- If new wells are hydrofracked while other orphaned wells are not plugged and abandoned, then the high hydrostatic pressures in new wells are likely to drive LNAPL, methane, and other contaminants upward into freshwater aquifers via these old, open, pathways. Drilling regulations and gas well permitting should not be advanced prior to identifying, locating, and properly sealing all orphaned, improperly plugged and abandoned wells, and leaking wells within one mile of planned new drilling operations. The regulations should be so amended to protect water quality in the Delaware River Basin.

Life of Aquifer

The DRBC draft regulations do not address the long-term cumulative impacts associated with gas drilling. Because the magnitude of gas drilling is areally expansive and requires repeated breaching of geologic confining beds that naturally protect freshwater aquifers, it is important that drilling regulations and permitting recognize the natural "*life of aquifer*". Aquifer protection requires the use of downhole methods and materials that, like aquifers, will stand the test of time and harsh physical conditions. Current state-of-the-art cement materials used in well completion and plugging and abandonment operations do not have a documented long-term history of durability. Cement mixtures or alternate sealant materials must be capable of maintaining the long-term hydrologic integrity of freshwater aquifers separate from deep underlying geologic formations that contain saline water enriched with natural gas, radioactive elements, and hydrofracture-related chemicals. Inherent in permitting and the regulation of gas wells is the concept that groundwater quality will be maintained and will be available as a potable water source in perpetuity.

Freshwater aquifers have taken millions of years to form. As geologic layer after geologic layer was deposited, buried, and eventually lithified over time, many became physically isolated from overlying strata. Some of the deeper bedrock horizons contain old, brine-rich, connate waters that are present in the pores of the bedrock. This saline water was either trapped in bedrock pores when the rock units were formed or became highly saline later in time through mineralization due to stagnant flow conditions (Fetter, 1994). Under natural conditions, this pore water is not encompassed by the hydrologic cycle. Gas drilling activities provide a mechanism whereby deep formation waters now have an avenue to commingle with overlying freshwater aquifers if failure of zonal isolation materials occurs.

Hydrologic risks relative to drilling activities are twofold. First, the upward release of a toxic soup of hydrofracturing chemicals and natural gas poses a water quality risk that could foreseeably continue for hundreds or more years until all chemicals have biodegraded. Second, long after chemical degradation has occurred, the risk of open borehole and fracture pathways resulting in the continued commingling of saline water and gases with freshwater may cause permanent, irreparable harm to our aquifers.

As we assess the draft drilling regulations, it is critical that we recognize the importance of maintaining the hydrologic integrity of our freshwater aquifers. These aquifers provide the life blood of our present society and need to continue to do so through future millenia. Geologically, the processes of sediment lithification, uplift and erosion of the landscape, and the development of bedrock fractures have taken eons to create the aquifers we require and enjoy today. Barring anthropogenic alteration of the physical constraints that isolate freshwater aquifers from deep connate waters, it is possible to conservatively assess both how long our freshwater aquifers have existed and how long they will exist.

It is reasonable to assert that the rate of erosion or evolution of the landscape that contains our freshwater aquifers (i.e., the rate of denudation) has proceeded more or less equally throughout the region, allowing for a number of glacial advances and retreats. Geologic work by Palmer (2007), Palmer and Rubin (2007), and Rubin (2009) in carbonates indicates that the current regional landscape hosted freshwater aquifers well in excess of one million years. Ritter et al. (2002) discuss regional erosion or denudation rates as determined by various geomorphologists. Generally, while regional denudation rates fall between 1 and 6 inches per 1000 years, a reasonable approximation for denudation on a continental scale is 1.2 inches per 1000 years. Denudation rates provided range from some 0.8 in/1000 yr for the Trenton, NJ Delaware River area to 27 m per million years (1.06 in/1000 yr) for the Juniata River, a tributary of the Susquehanna River in central Pennsylvania. Based on these numbers and the wide range of topographic elevation in Delaware River Basin watersheds, it is reasonable to conclude that the regional base level lowering required to form the present aquifers took far more than one million years. Bloom (1998) found that rates of denudation by limestone solution, as discussed by Palmer and Rubin, are comparable for other strata.

Similarly, it is reasonable to assume that the present geologic and hydrologic conditions will permit fresh groundwater extraction for the next million plus years. It then follows that it is incumbent upon those regulating the gas industry to require that the drilling methods and construction materials used be capable of effecting zonal isolation for a period of time in excess of 1,000,000 years – the life of aquifer required by untold future generations. If this cannot be safely demonstrated, then it would be premature to risk the hydraulic integrity of our freshwater aquifers for short-term energy needs.

As a young, technologically advancing society it is incumbent upon us to regulate responsibly and conservatively earth-altering activities that might potentially breach the hydrologic integrity and life of our aquifers. If we reasonably assume, as discussed above, that generations of our offspring will continue to require clean groundwater, we must plan accordingly. Drilling regulations must contemplate and insure that our freshwater aquifers are not compromised by short-sighted drilling activities that have the real potential of forever altering aquifers. For water supply and water quality planning purposes, drilling regulations should address a one million year life of aquifer timeframe.

Boreholes that breach deep confining beds provide dangerous pathways for the upward release of chemicals, connate water, and gases. While even small numbers of leaking wells can result in aquifer contamination, the potential failure (i.e., leakage) of thousands of wells pose risks of unprecedented proportion. <u>Freshwater aquifer protection requires a well sealing technology that matches and restores the natural hydrologic integrity that exists before drilling commences.</u> Thus, well plugging and abandonment sealants must be capable of remaining intact for at least one million years. If, for example, concrete well plugging mixtures have a "*life of well*" expectancy of, say, only 100 years - then it would not be prudent to jeopardize our freshwater aquifers. If we use this 100-year *life of well* example as a maximum expected *life of well*, then drilling regulations should require provision for re-boring and seal replacement in all wells every 100 years. This would then calculate to 10,000 cement plug re-boring and re-plugging events over an expected *life of aquifer* of 1,000,000 years. The proposed gas drilling regulations must provide financial protections and regulations to cover this aquifer maintenance work, inclusive of inflation increases. It should be noted that an ongoing re-boring and re-plugging well maintenance program will only address borehole contaminant vectors, not hydrofracked opened bedrock fracture pathways.

Life of Well

Wells are cased and grouted for zonal isolation and water quality protection. Durable zonal isolation is key to minimizing problems associated with annular gas flow, sustained casing pressure development, and aquifer contamination (e.g., Brufatto et al. 2003; Ladva et al. 2005). The oil and gas industry has long recognized the need to maintain the long-term integrity of boreholes that breach bedrock formations that have naturally and effectively isolated freshwater aquifers from deep connate waters for millions of years. Research continues in efforts designed to lead to better practice and better cement formulations, including some self-sealing mixtures that are newly developed but have not been tested for years in the harsh downhole environment. The critical nature of improperly or failed hydraulic seals is accented by the sheer number of orphan wells and the tens of thousands of wells now planned in the Delaware River Basin. Similarly, the magnitude of the problem of downhole cement failure is highlighted by the extensive literature on the subject present in petroleum industry papers that discuss the situation and efforts to improve cement mixtures and application. Each gas well represents a potential conductive pathway capable of transmitting gases and fluids upward into freshwater aquifers. Numerous studies, modeling exercises, and papers document industry efforts to perfect hydraulic seals used both during the productive life of wells, as well as during plugging and abandonment procedures. Because assorted cement mixtures are used to seal wells, current state-of-the-art industry cement integrity will be examined here. Very long-term cement integrity is needed to protect the quality of freshwater aquifers (i.e., over a million--plus years).

Mechanisms contributing to gas leaks include channeling, poor cake removal, shrinkage in the cement sheath, and high cement permeability (e.g., Dusseault et al. 2000; Ravi et al. 2002;

Newhall 2006). Some common cement failure mechanisms are portrayed in Figures 1 and 2. [All report figures may be viewed and downloaded at http://hydroquest.com/DRBCfigures/] Cement shrinkage leading to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing is recognized by numerous industry experts (e.g., Dusseault et al. 2000). Dusseault discusses related issues:

> *"Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned (P&A). ... However, why does it take so long for the gas to get to the surface (sometimes decades)? ... The consequences of cement shrinkage are non-trivial: in North America, there are literally tens of thousands of abandoned, inactive, or active oil and gas wells, including gas storage wells, that currently leak gas to the surface. Much of this enters the atmosphere directly, contributing slightly to greenhouse effects. Some of the gas enters shallow aquifers, where traces of sulfurous compounds can render the water non-potable, or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems to come out when taps are turned on. ... Now, a condition exists where gas and liquids are entering the wellbore region behind the casing and leaving it at a higher elevation. This is a loss of zonal seal, and could have negative effects, such as pressurizing higher strata, or leakage of brines and formation fluids into shallower strata causing contamination."*

Cement shrinkage, debonding, and failure can result from a variety of causes including too high a water content, water expulsion, shrinkage after setting and during hardening, radial cracking, tensile failure, compressional failure, traction, cement dehydration, osmotic dewatering in the presence of high salt content formation brines, corrosive gases, high formation pressures and temperatures, changes in temperature and pressure, sustained casing pressure (SCP), poor cement blends, pressure testing, gas and water channeling, gas migration through setting cement, influx via mud channels, internal and external microannulus development, cement shattering, and cement plastic deformation (e.g., Dusseault et al. 2000; Heathman and Beck 2006; Brufatto et al. 2003; Kellingray 2007; Lecolier et al. 2006; Newhall 2006; Mainguy et al. 2007; Teodoriu et al. 2010; Ladva et al. 2005; Moroni et al. 2007; Ravi et al. 2002; Gray et al. 2007; Reddy et al. 2007; Darbe et al. 2009; Bellabarba et al. 2008; Daneshy, 2005; Crook and Heathman 1998; Boukhelifa et al. 2005; Tahmourpour et al. 2008).

Problems with the integrity of well cement are well known in oil and gas fields. For example, twenty-five to thirty percent of wells in one shelf study area were estimated to have annular pressure problems (SCP) in five to six years, reaching 60 percent in 27 years (Kellingray 2007). Fractured shales of the Appalachian Basin may present problems when cementing wells (Newhall 2006). Newhall states:

> *"These problems include cement dehydration due to excessive fluid loss or formation "breakdown," in which whole cement slurry is lost to a created hydraulic fracture. When this situation is encountered, it can be difficult to achieve proper cement tops and cement bond quality can be poor."*

The literature of the petroleum industry is rich in papers that discuss various cement properties, short-comings, different mixtures best suited for assorted downhole situations, new additives, problems with outdated cement standards, the lack of availability of needed cement types, and the use of finite element modeling to simulate downhole conditions, all of which seek to refine optimal well completions (e.g., Heathman and Beck 2006; Gray et al. 2007). The draft DRBC regulations are devoid of detailed cement composition standards and optimization requirements and the means by which they should be tailored to each gas well. Determination of well-specific cement composition, short-term integrity validation, long-term integrity validation, and long-term care and maintenance (i.e., re-boring and replacement through 1,000,000 years with financial assurances) should be incorporated into the DRBC regulations. These regulations should be detailed in the regulations themselves such that they supercede any lower state standards in all states in the Delaware River Basin, not left to the discretion of individual states.

Lecolier et al. (2006) break out the lifetime of a well as follows: the production period ~20 to 40 years, the post-abandonment period (some tens of years following permanent well abandonment), and the abandonment period (several centuries). These authors conducted short-term durability ageing tests on cements in contact with sour gases (i.e., H_2S and CO_2). Their work showed severe deterioration of the properties of Portland cement-based materials, enough for them to conclude that alternate cementing materials have to be designed. Bellabarba et al. (2008) state that the life expectancy of a producing well is perhaps 20 years, as compared to the likely production-injection life span of underground gas-storage wells of 80 years or more. Kelm and Faul (SPE and Halliburton, 1999) state than a typical production life of a well is 15 to 20 years. These authors point out that "*for successful well abandonment, operators must understand that meeting required regulations does not alone ensure long-term protection of the environment*." They state that operators must decide for themselves whether the cost associated with best practices is justified for an individual well. They continue:

> *"Specifically, they must determine how long the abandonment must be effective to allow nature to restore the pressure balance that existed before the well was drilled. Because nature moves at its own pace that is measured not in years, but in geologic time, abandonment must be effective indefinitely. Every well is unique: therefore, each well's abandonment should be individually designed."*

> *"An optimal well abandonment would include plugging the hydrocarbon-bearing formation matrix, and filling all casing strings from top to bottom with cement designed for the well conditions. The cement would be allowed to set in a clean, gas-free environment. Each annulus would be clean before the cement is placed. This kind of abandonment is often too expensive to be practical."*

The need for detailed regulations and well field oversight is obvious.

Recent assessment of the life of gas production wells indicate that the bulk of gas production occurs in the first 4 to 7 years of a well. Dr. Arthur Berman examined production data from nearly 2,000 horizontal gas wells drilled in the Barnett Shale and found that the average commercial well life is 7.5 years, with the most common well life being only 4 years, not the 40^+ years often claimed by operators (Konrad 2009). These lower well life values are supported by a

Chesapeake Energy graph titled: Marcellus Shale – Targeted Horizontal Well Profile that depicts Production Rate vs. End of Year Decline Rate. The 10-15-09 graph shows that most of the gas production is depleted within 4 to 5 years.

It is important to recognize that once our natural resources have been compromised as a result of an operator error, grout and/or casing failure, a major contaminant excursion, seismic activity, or an unforeseen breaching of geologic beds, it may be impossible to remediate and restore them to their pre-existing conditions. Failed confining beds and contaminated natural resources often represent an irrevocable commitment of our lands. Our decision to risk natural resources in the Delaware River Basin must weigh all the health and environmental risks against exploitation of relatively short-lived gas reserves and financial gain.

Life of Concrete

The draft regulations do not detail appropriate cement mixtures and mechanical properties (i.e., quality, density, thermal stability, compressional strength, tensile strength, strength retrogression, permeability, percent shrinkage, consistency, durability) modeling to determine optimal sheath integrity and the long-term ability of cement to effectively protect freshwater aquifers. The life of concrete as related to its structural integrity is critical in maintaining zonal isolation between deep saline gas horizons and freshwater aquifers. Yet the reality is that each mill run produces different non-uniform cement compositions that have different thickening times, compressive strengths, and fluid loss characteristics (Myers 2000; Rogers et al. 2006a; Rogers et al. 2006b). Because we must plan for continued aquifer usage for the next one million plus years, it is imperative that we do not promulgate gas drilling regulations that will forever disrupt the existing hydrogeologic flow regime. It is entirely possible that the cumulative impacts of hundreds and thousands of failed gas wells may in a matter of decades irreparably harm the structural and hydrologic integrity of deep geologic beds that developed naturally over millions of years.

Gas wells drilled through deep confining beds will compromise the water quality of freshwater aquifers if all of them are not hydraulically sealed in such a way that no fluid or gas migration can occur upward over the entire life of the aquifers. As discussed above, the hydraulic seals must be effective for one million plus years. It would not be prudent to promulgate drilling regulations that did not involve a mechanism that will forever guarantee the long-term protection of freshwater aquifers in the Delaware River Basin, as well as throughout other watersheds of the world. To insure real long-term aquifer protection (i.e., > 1,000,000 years), the effective life of the concrete or other material being used as a hydraulic seal to assure zonal isolation must be known. This will be discussed below. We must not extract finite gas resources at the expense of leaving our freshwater aquifers riddled with thousands of failing and failed gas wells that will, without doubt, eventually release deep contaminants as the cement forming zonal seals degrade over time. As already seen in Dimock, PA and many similar situations, aquifer contamination is already occurring - long before wells are plugged and abandoned. An analogy that may help people envision the risk of upwardly pressurized gas forcing its release alongside and through failing wellbore concrete is as follows. One could turn the wellbore-geologic setting on its side and consider the chemical and gas-laced fracking fluid as reservoir water pushing against a dam fitted with numerous pipes plugged and secured with concrete. With time, pressure, corrosion, and slow cement and pipe failure – leaks would develop outside and within the plugged pipes, thereby releasing contaminants into air or the freshwater aquifer on the downstream side of the dam.

The draft regulations should be amended to take into account downhole condition changes and cement alteration that take place after well abandonment. Failure to do so will almost certainly result in breached plugs, commingling of formation waters, and contaminated freshwater aquifers. Mainguy et al. (2007) provide important conclusions:

> *"The sealing materials used for well plugging and abandonment must be adapted to the downhole condition changes that take place after well abandonment. Actually, if the plug wells are located in a field for which pressure, thermal, and stress state are not in equilibrium at the beginning of abandonment, the downhole condition changes during abandonment can lead to plug failure or micro-annulus formation inducing fluid leakage along the well. … The risk of debonding at the cement/rock interface must also be closely analyzed in future studies because it will largely reduce the plug sealing capacity."*

Heathman and Beck (2006), among other petroleum geologists, have also recognized the problems associated with debonding and the creation of micro-annuli (see Figure 2). Ladva et al. (2005) discuss the 2001 work of Read et al. who examined Portland cement plugs placed in cored-out holes with temperatures between 65 and 85°C for 12 months. Core sections analyzed by microprobe and X-ray diffraction revealed significant mineralogic and texture changes reflecting transport of calcium and other minerals, a leached appearance, and increased porosity due to dissolution of portlandite. Moroni et al. (2007) state when discussing long-term isolation that "*Gas storage wells have long lifetimes (80 years or more) compared with oil and gas productions wells*." These authors discuss a new self-healing sealant system that, while unproven in the long-term, may hold some promise for zonal isolation for the productive lifetime of a gas well (i.e., approx. 20 years). Bellabarba et al. (2008) also discuss industry improvements made toward zonal isolation via a new, long-life, self-healing cement (FUTUR cement). Early test results reveal marked improvement in reducing oil and gas leakage through channels. While the properties of self-healing cements are encouraging, harsh "*changing downhole conditions remain the enemy of cement sheaths and may cause even well-placed sheaths to fail over time*" (Bellabarba et al. 2008).

Improperly abandoned wells can become a significant threat to groundwater quality (Mainguy et al. 2007). Documentation of the life of concrete is limited, especially relative to the downhole gas field environment. As discussed above in the Life of Well section, the risk of concrete failure is ever-present due to many factors. A reasonable approximation of the life of concrete comes from assorted literature sources, as well as modeling results. As discussed above, some of the sources are based on concrete assessments conducted outside of a downhole setting, by making use of nuclear and construction industry studies. Review of literature information provides a crude means of assessing the likely life of concrete under optimal conditions.

Perhaps one of the best model simulations of well plug failure was conducted by Mainguy et al. (2007). These researchers assessed compressive and tensile loads, among other factors, and found that the earliest failure surface was reached at 150 years. However, their modeling exercise clearly acknowledged two key points: 1) "*de-bonding between rock and cement is expected to happen because of their different material properties*", and 2) their modeling work assumes "*that the plug and the rock remain fully bonded once the plug is sealed*". Thus, it is highly likely that well plug failure will occur far in advance of 150 years.

Clearly, the best means of assessing the durability of concrete sheaths and concrete plugs is via examination of oil and gas field concrete, preferably based on in-situ samples, as well as by assessing the integrity of existing new and old wells. However, concrete exposed to harsh surface conditions, often in the presence of sodium chloride, in structural applications may also provide some insight into long-term durability.

For example, Broomfield et al. (2003) assessed the durability and performance of reinforced concrete on two different highway projects (a 40-yr tunnel and a highway construction project). They used empirical data and models to estimate the time to corrosion, cracking and concrete spalling. Initial tunnel corrosion rates ranged from 0.2 to 0.4 μm/yr (20 to 40 μm/100 yr). If this space were continuous within a wellbore, gas would be able to move upward to overlying horizons. Gray et al. (2007) state that a microannulus of 0.001 inches (25.4 μm) is sufficient to allow a gas flow path.

Noik and Rivereau (1999) conducted experimental work to compare the durability performances of several types of concrete and slurry formulations under different temperatures and pressure conditions over a two year period. Their Class G cement results for a time period of about 596 days show a significant decease in compressive strength and increase in permeability. Assorted researchers are evaluating the service-life of reinforced concrete structures susceptible to chloride corrosion (e.g., Trejo and Pillai 2003). Similarly, Shiu (2011), of Walker Restoration Consultants, states that reinforced concrete structures generally have a service life of 30 to 40 years. Their work may help assess the maximum potential service life of concrete under various conditions. Research to date indicates that the life of concrete in both above ground and downhole conditions, under the best of circumstances, may be less than 100 years. Even if this preliminary assessment is in error by an order of magnitude and the life of concrete is 1,000 years, this time frame for the design life of concrete very quickly results in jeopardizing the useful life of Delaware River Basin aquifers in far less than 1,000,000 years – in only 0.1 percent of the conservatively estimated life of aquifers.

If, for example, state-of-the-art concrete mixtures are only viable for 100 years, then it reasonably follows that the regulations permitting a massive basin-wide drilling program must have a solid provision that guarantees re-boring and re-cementing of wells every 100 years over the course of one million plus years (i.e., 10,000 plus times). If the concrete hydraulic seal of a plugged and abandoned well has a life of concrete of 100 years, then legal and financial guarantees of long-term maintenance must be incorporated into basin-wide regulations that hold equally for each state. The regulations must look far beyond the short-term gas reserves obtained in the proposed "gas-rush" and must responsibly guarantee clean, potable, freshwater to our children, our grandchildren, and the next 50,000 generations that will also need this water over the course of the next 1,000,000 years. Rushing into promulgating drilling regulations for short-term energy needs must not be pushed forward at the expense of irreplaceable freshwater resources.

Additional Life of Concrete Material - Plus Life of Steel

Different states in the Delaware River Basin have different well installation and plugging procedures which are not, but should be, standardized throughout the DRB. Based on references and discussions provided in this report, it is clear that even the best state-of-the-art cementing and casing materials are not likely to be able to insure long-term zonal isolation between gas production zones and overlying freshwater aquifers. This is due to the corrosive nature of casing pipe and the many cement failure mechanisms discussed. It appears, based on the literature cited in this report, that aquifer water quality protection may be degraded in less than 100 years.

Even if this figure is doubled or quadrupled, the upward migration of methane and other contaminants that naturally occur in gas-bearing shales is virtually assured. The design life of gas wells must not be based on little more than the productive life of the wells (about 4 to 20 years), but must instead plan for the long-term protection of freshwater based on the productive life of the aquifers (one million plus years).

CONCLUSION: At this time, existing casing, cementing, and plugging regulation provisions cannot accomplish this because the durability of materials available is not capable of matching the geologic scale needed for long-term aquifer protection.

Using Pennsylvania as an example (State of Pennsylvania, 1989, 25 Pa. Code § 78.81), State codes require the operator to case and cement a well to:

> *"(2) Prevent the migration of gas or other fluids into sources of fresh groundwater.*
>
> *(3) Prevent pollution or diminution of fresh groundwater."*

Thus, while the regulations diligently seek to apply today's technology to best exploit gas reserves, the long-term legacy will be one of a landscape riddled with thousands and thousands of open boreholes (i.e., due to failed and corroded cement sheath and casing material) that allow the free migration of gaseous and other gas shale pollutants into DRB freshwater aquifers.

RECOMMENDATION: The draft DRBC regulations should be placed on hold until such time as material degradation problems have been fully and adequately addressed such that the intent of State regulations can be accomplished.

Assessing the durability or life of concrete is difficult because few or no long-term assessments have been conducted, especially as related to a geological time scale (i.e., the life of aquifer). Many factors contribute to the durability of cement and thus the effectiveness of zonal isolation. To avoid upward leakage of polluting fluids and gases, permanent zonal isolation must be effective for hundreds of thousands of years. This requires the use of sheath and plugging materials that can withstand harsh downhole conditions long after well abandonment. Lécolier et al. (2007) reasonably assume that the permeability of cement-based material is a relevant index of its durability. They carried out ageing tests on hardened cement paste corresponding to three different experimental conditions. They measured mechanical strength and water permeability of samples in the absence of large crack and micro-annuli pathways in the cement sheath and/or plug and found that the transport of fluids is mainly a diffusive process. After only one year, samples left in the same water showed a slow decrease in cement compressive strength and a loss of about 20 percent of mechanical integrity. The decrease in strength is linked to both a higher porosity and a coarser pore size distribution. The higher the temperature, the earlier and the more important the loss of mechanical integrity (Lécolier et al. 2007). When the ageing fluid was renewed with low salinity brine, the compressive strength decreased by 50 percent. After one year significant leaching of the outer layer of Portlandite was observed under these two settings. The authors point out the "*huge*" need to mimic *in situ* leaching processes of cement-based materials "*before being able to forecast cementing and plugging material durability*".

Roth et al. (2008) address the need for new zonal isolation materials that can maximize productivity and longevity of wells. While recognizing that great advances have been made in cementing practices over the years, they point out that this work does not address damage to the cement sheath that may occur years after the cement has set. They document the magnitude of the industry-wide problem of cement sheath integrity by referencing various studies. For example:

> *"● In the United States, 15% of primary cementing jobs fail, with one in three of these failures attributed to gas or formation fluid migration (Newman 2001). …*
>
> *● In a report retrieved in February 2007, the Alberta Energy and Utilities Board records over 18,000 wells with instances of SCVF or Gas Migration."*

They further discuss the poor durability of cement squeeze jobs as seen in the high percentage of failed cement sheaths that exhibit sustained casing pressure (SCP). They report that Alberta regulations require that within 90 days of a well being completed it must be tested for SCP and gas migration, followed by reporting within 30 days and correction within 90 days. A high percentage of cement squeeze repairs fail. In an effort to address the loss of hydraulic integrity <u>after</u> cement has set, Roth et al. tested a new self-sealing system designed to increase the long-term durability of the cement sheath in oil and gas wells. The self-healing cement must be installed during the primary cementing operation. Test results are promising in terms of self-healing cement cracks and micro-annuli exposed to oil and natural gas. A significant decrease in gas flow from 350 mL/min to 5 mL/min was documented during a test.

RECOMMENDATION: Although the long-term durability of this new self-healing cement (SHC) has yet to be determined beyond 18 months (which was excellent), consideration should be given to requiring its use in the Delaware River Basin. The DRBC should adopt regulations that assure cement/zonal integrity or put its draft regulations on hold until technical advances can provide cement job/zonal isolation competence.

Studies of concrete degradation in above ground settings provide information on the durability of concrete which roughly correlate with factors affecting the durability of cement sheaths in gas wells. Tikalsky et al. (2004) provide additional insight into the durability of concrete, albeit in an above ground physical setting in Pennsylvania where the average life of concrete bridge decks has been between 25 to 27 years. They identify the deterioration of concrete as typically being associated with the diffusion of chlorides into the concrete and the subsequent propagation of corrosion product.

The authors detail potential new concrete mixtures now being tested as part of the "100-Year Highway" I-99 Test bed project. While long-term monitoring is the only true measure of success, they are hopeful that their new concrete mixtures may extend the life of bridge decks to 75-100 years. By analogy, above ground bridge decks are also exposed to harsh conditions and, as such, provide a ballpark approximation of above ground life of concrete as being about 100 years under the best of circumstances, and assuming the construction methods were executed using best management practices and best technology.

Trocȯnis de Rincȯn et al. (2004) tested various concrete specimens in different environments with and without reinforcement to assess corrosion deterioration in concrete structures. They concluded that reinforcement corrosion varies by environment and factors such as concrete quality, CO_2 content, and chloride content in the atmosphere. Otieno et al. (2009) also document the increase in concrete permeability associated with cracks that allow ingress of corrosive agents (moisture, chlorides).

They further point out that the subsequent increased corrosion rate results in a finite service life for any reinforced concrete structure. In many ways, the combination of steel surface casing and cement sheaths in gas wells have similar, if not more severe, exposure than do above ground reinforced structures. Pfeifer (2000) reviewed chloride permeability issues for both conventional and high performance concretes used in bridge decks and other structural applications. He determined that the very best concrete and corrosion-resistant reinforcing bars might be able to achieve a 75- to 100-year, crack-free, design life. All told, if we double the life of downhole and above ground life of concrete to 200 years, it is clear that the zonal isolation/cement integrity needed to protect our freshwater aquifers has a high potential of being irreparably harmed in the short-term - far before the time scale required for long-term life of aquifer protection.

CONCLUSION: The very best concrete and corrosion-resistant reinforcing bars might be able to achieve a 75- to 100-year, crack-free, design life.

RECOMMENDATION: Drilling regulations and gas well permitting should not be advanced prior to clearly established program goals and zonal sealant materials that are protective of the life of aquifers.

Cement life may also be impacted by other factors. Corrosive or sour gases (e.g., > 2% CO_2 and/or > 100 ppm H_2S) may lead to enhanced degradation of cement and corrosion of steel casing materials (Lécolier et al. 2007). Acid attack of cementitious materials takes place when in contact with acidic aqueous solutions, the stronger the acid concentration the greater the degradation.

Investigation into safe geological underground storage of CO_2 has brought about intensified interest in the stability and integrity of cement used in wellbores. Every effort must be made to reduce the risk of CO_2 leakage back to the surface via wellbores. Chemical research, field assessment, and experiments have shown that CO_2 rich acid gases can corrode, degrade and disintegrate casing cement in time periods ranging from 7 days to 15 years (Condor et al. 2009).

Similarly, cement exposure to acid gases can significantly increase cement permeability. Experiments conducted by Condor et al. (2009) also determined that the space between the cement plug and casing could be the most plausible path of CO_2 leakage in a wellbore. Krilov et al. (2000) document cement deterioration caused by CO_2 corrosion after only 15 years of well production under high temperature conditions, thereby demonstrating a loss of compressive strength and structural integrity of the cement sheath, as well as the short life of cement under hostile downhole conditions.

CONCLUSION: Cement life may be significantly shortened by exposure to corrosive or acid gases.

RECOMMENDATION: The concentrations of CO_2 and H_2S in DRB gas wells should be assessed and weighed against the potential requirement of specialty acid gas resistant concrete or other sealant methodology prior to adopting amended plugging and abandonment regulations.

Teodoriu et al. (2010), like many other petroleum geologists, state that:

> *"A well maintains its integrity if it effectively achieves zonal isolation over its productive life. However, maintaining integrity is not always the case in real life oilfield practice as case histories abound where the integrity of the well was compromised due to failure of the cement sheath leading to loss of money and production."*

It is important from a hydrogeologic/water quality standpoint that the words "*zonal isolation*" be defined in terms "*life of aquifer*" such that no contaminant pathways become open due to cement sheath and surface casing failure and corrosion. Boukhelifa et al. (2005) discuss the loss of zonal isolation caused by mechanical failure or by development of a micro-annulus. They performed large-scale laboratory testing of the cement sheath to simulate various downhole stress conditions and evaluate sheath durability. They simulated loading in close to real field conditions, many of which generated cement failure with observable creation of a micro-annulus, debonding, radial cracks, and increased permeability. They conclude that during the life of a well, a) the cement sheath is likely to experience deformation cycles resulting (in most cases) in the loss of sealing integrity if adequate materials are not anticipated, and b) the life of the well may be greatly extended by selection of the most appropriate sealant.

Loss of zonal isolation as a result of cement sheath failure is the subject of numerous papers, laboratory testing, and model analyses. This is because the durability of downhole cement has only very limited *in-situ* data, yet the problems associated with cement failure are widespread and recognized throughout the industry. Mainguy et al. (2007) provide a reservoir field analysis of the risk of well plug failure after abandonment and address the long-term durability of sealing materials used to plug wells. While they recognize that debonding at the cement/rock interface may occur first due to pressure changes, tensile failure, and other factors, model runs indicate that plug failure might not occur for 150 years. The authors point out that their model assumes that the plug and rock remain fully bonded once the plug is sealed.

CONCLUSION: Effective zonal isolation must be considered relative to the life of aquifers. Even the best primary cementing jobs using the best cement mixtures are likely to fail as a result of repeated and highly varied stresses exerted on cement sheaths (e.g., repeated hydrofracturing episodes; pressure variations; compressive, shear and tensile stresses; plastic deformation or strain in the casing).

RECOMMENDATION: Drilling regulations and gas well permitting should not be advanced prior to clearly established program goals and zonal sealant materials that are protective of the life of aquifers.

New cement formulations, including the development of self-sealing cements, if used, are encouraging and will reduce sheath failure. However, numerous petroleum geologists recognize the potential damage to cement sheath integrity from repeated stresses (e.g., Tahmourpour et al. 2008; Roth et al. 2008). **Furthermore, to a large extent, the industry heavily focuses on maintaining sheath integrity over the short term life of the well vs. the geologic scale needed to maintain zonal isolation for long term water quality/aquifer protection.**

For the most part, industry papers address concerns regarding cement integrity, testing cement quality and mechanical properties, development of new cement mixtures, and modeling to better understand how to best optimize future cement mixtures. Research to date has not identified any technical petroleum industry papers that specifically address long term cement durability based on assessment of actual field data. Mainguy et al. (2007), however, as discussed above, provide an excellent model-based assessment. The draft DRBC regulations should not be advanced until such time as long-term integrity of cement sheaths and casings or other sealant materials used to effect zonal isolation are demonstrated.

James and Boukhelifa (2008) critically review assorted inconsistencies between previous analytical or finite-element models that discuss the long-term mechanical durability and failure of the cement sheath. They point out that there are currently no industry-standard procedures available for determining all the cement parameters required for input into cement-sheath-integrity models. They provide self-consistent methods to determine cement mechanical properties. They then use new measurement methods with field data to demonstrate the mechanical durability of flexible cement systems aged at high temperatures for up to one year – "*the first time that mechanical durability has been demonstrated over such a long aging time*." Their work supports models as important means of assessing cement durability in the absence of actual long-term data. It also reinforces the need for long-term rigorous durability data before potentially placing freshwater aquifers in jeopardy.

CONCLUSION: Research indicates that there is no empirical information supporting long-term cement durability in gas wells. Because of industry wide problems with cement integrity, new formations of cement are being developed and tested.

RECOMMENDATION: Models should be used to assess cement durability in the absence of actual long term data prior to approval of drilling in the DRB. This supports the need for a moratorium of gas drilling at this time.

Hewitt (1987) documents the explosion of a homeowners pump house and the contamination of 13 additional homes with combustible levels of methane gas in Chautauqua County, New York in 1983. In addition, a municipal well one mile away also found measurable levels of methane. Testing of the gases via radiocarbon dating methods confirmed that their origin was from the underlying Devonian shale. The data solidly pointed to the source of the problem as being newly installed deep gas wells, thus documenting methane migration through a fresh water aquifer some 27 years before today.

Hewitt (1987) and Harrison (1985) discuss the likely contaminant transport pathway up overpressured annuli of gas wells. In this situation, strong upward (i.e., positive) pressure from the producing zone creates a decreasing hydraulic gradient between contaminants in the annulus (e.g., LNAPL, brine, methane) and overlying freshwater aquifers. **Thus, overpressurization of well annuli provide a hydraulic driving force that may drive contaminants into aquifers.**

Harrison (1985) provides an outstanding discussion, with excellent illustrations, of the mechanics of gas and fluid migration upward and rapidly outward from gas production zones. **His discussion includes the important point that the solubility of methane increases directly proportional to pressure, thereby readily explaining the rapid depressurization and release of methane in homeowner wells.** Other instances of gas field contaminants degrading freshwater aquifers are discussed by Harrison (1983) and Novak (1984). With time, cement failure, and casing corrosion - annular pathways may follow cement cracks, micro-annuli inside and outside the production casing, and the annulus created where the casing has corroded away.

CONCLUSION: A short life of cement directly equates to a high potential for groundwater contamination. The issue of groundwater contamination stemming from gas wells has not been solved in almost three decades time since the Chautauqua County situation discussed. In this instance methane contamination was documented over a mile from its source and across a valley.

RECOMMENDATION: Drilling regulations and gas well permitting should not be advanced prior to clearly established program goals and zonal sealant materials that are protective of the life of aquifers.

The presence of orphaned or improperly plugged and abandoned wells within close proximity of planned new drilling operations (say one mile) pose a <u>very</u> significant risk to water quality in overlying freshwater aquifers. If new wells are hydrofracked while other orphaned wells are not plugged and abandoned, then the high hydrostatic pressures in new wells are likely to drive

LNAPL, methane, and other contaminants upward into freshwater aquifers via these old, open, pathways. The hydraulic forces involved are discussed above and by Harrison (1985).

The need to sequester CO_2 in deep geologic substrates to reduce the impacts of global warming has spurned a very serious look at our ability to effectively isolate and confine CO_2 underground.

Distinguished Henry Darcy Lecturer Michael Celia (2008) points out this same very serious problem relative to the underground sequestration of carbon dioxide, much like what we face relative to methane migration in gas fields. The article states "*that deep mid-continent sedimentary basins offer one of the best environments for CO_2 injection, but millions of old oil and gas wells can serve as conduits for leakage of the CO_2*". Nicot et al. (2006) also pointed out that "*multiple perforations resulting from intensive hydrocarbon exploration and production have weakened seal integrity in many favorable locations* (for CO_2 sequestration). *Even oil and gas wells abandoned to current standards cannot be guaranteed to be leak-free in the long term*." Barlet-Gouédard et al. (2006) discuss their concern about long-term wellbore isolation and the durability of hydrated cement that is used to isolate the annulus across the producing/injection intervals in CO_2-related wells. They state:

> *"With the lack of industry standard practices dealing with wellbore isolation for the time scale of geological storage, a methodology to mitigate the associated risks is required."*

In response, Barlet-Gouédard et al. conducted laboratory qualification of resistant cements and long-term modeling of cement-sheath integrity. Their work accented the evolution of cement chemistry and porosity with time, comparing Portland cement with a new CO_2 resistant material. A sharp and rapidly advancing alteration front was documented for Portland cement. It had a high porosity, thereby providing a potential pathway for gas excursion along a severely deteriorated cement sheath. The new CO_2-resistant material performed better and exhibited no alteration front, confirming the value of ongoing research designed to improve cement quality.

CONCLUSION: Orphaned and/or improperly plugged and abandoned wells in basin areas with planned gas drilling operations are open vectors for the release of contaminants into freshwater aquifers. Hydraulic fracturing operations that pressurize pre-existing fractures hydraulically connected to these wells will drive contaminants into aquifers.

RECOMMENDATION: Since CO_2 is commonly associated with methane (CH_4), the risk of acid gas corrosion of cement and casing in the DRB should be assessed prior to promulgation of drilling regulations. Drilling regulations and gas well permitting should not be advanced prior to identifying, locating, and properly sealing all orphaned or improperly plugged and abandoned wells within one mile of planned new drilling operations.

The National Ground Water Association (1992) adopted the position "*that all abandoned wells and boreholes which penetrate aquifers or breach a zone that provides a significant barrier to contaminant migration should be decommissioned, so as to prevent any contamination from entering or circulating within or leaving such structures*." This includes oil and gas wells that should be plugged with the goal of restoring "*the hydrogeologic characteristics of the site and* *prevent the abandoned well or borehole from being a potential conduit for surface contamination or cross contamination of the aquifer*."

RECOMMENDATION: Thus, to avoid large-scale aquifer contamination in the DRB, all new drilling operations should be stopped in areas with unplugged or poorly plugged wells until after they have all been properly plugged and abandoned.

Life of Steel

Corroded carbon steel casings left in plugged and abandoned gas and oil wells may provide yet another significant pathway (i.e., conduit) for LNAPL, brines, and gaseous contaminants to reach freshwater aquifers even if cement remains intact. Schnieders (2009) addresses iron corrosion of downhole pipes in any water with a pH below 9.3 and acidic H_2S rich groundwater. Even relatively thin casing wall thicknesses of say 9.5 mm to 12.7 mm (0.375 to 0.5 inches) far exceed the 0.025 mm (0.001 in.) threshold required for gas flow. The time it takes low carbon steel to significantly corrode is on the order of 80 years or less (Yamini and Lence 2010). Driscoll (1986) also addresses significant corrosion-related factors that can severely limit the useful life of water wells including reduction in strength, followed by failure of well screen or casing and inflow of low-quality water caused by corrosion of the casing.

Even stainless steel (at least as manufactured in the 1960s) may not be corrosion resistant in subaqueous, oxygen-poor, downhole environments because the outside protective layer may breakdown in the presence of chlorides or sulfates (Ahrens 1966). Simon et al. (2010) provide documentation of a worst case failure of a lined sour gas pipeline due to internal corrosion. The pipeline was carrying natural gas. In this instance, corrosion behind a liner placed within a steel pipeline in 2003, resulted in pipeline failure in just under four years of service life. Internal corrosion, at least partially due to methanol permeation, over a short length of the pipe removed almost 90 percent of the pipe wall. While this was a localized problem, time and corrosive conditions may lead to more widespread pipe failure (see Figure 1).

Chloride rich formation waters may significantly increase casing corrosion rates. Sun et al. (2004) document severe casing corrosion because of their exposure to corrosive environments, including saline formation water. They state that corrosion develops pits and cavities at both the inner and outer walls of the casing where the related strength deterioration can significantly shorten the casing life and may even cause failure of the well.

All new and most old gas well installations require placement of surface casing and a cement sheath to isolate and protect freshwater aquifers. In time, the iron casing pipes will corrode, thereby providing upward pathways for pollutants from shale gas horizons. Several lines of current research provide insight into the design life of casing pipes. Iron pipes placed in less harsh, near-surface, environments provide important data on the likely service life of steel. While it is recognized that the physical environments are not exactly the same, the information gained provides reasonable ballpark guidance on potential steel longevity.

Based on 1379 physical inspections of buried iron water lines conducted over 50 years, Kroon et al. (2004) determined that a useful pipe life of 75 to 100 years is achievable. Some cast iron pipes in low to moderately corrosive soils have demonstrated performance of more than 100 years. In a two-year study of corrosion and corrosion protection characteristics of ductile iron pipe, they determined that similar results could be expected.

Yamini and Lence (2010) developed a relationship that determines the rate of internal corrosion in cast iron pipes as a function of chlorine concentration and other factors. Their results indicate that the likelihood of failure is nearly 50% by the 80th year for a 203 mm (7.99 in) diameter pipe with a wall thickness of 10 mm (0.394 in) based on an initial chlorine concentration of 1 mg/l. Their sensitivity analysis revealed that the probability of pipe mechanical failure was most strongly influenced by chlorine concentration after 30 years of pipe age. Similarly, Sadiq et al. (2004) estimated a 50% probability of failure in the 70th year of pipe age.

Cast iron pipes will corrode externally and internally under aggressive environmental conditions (i.e., presence of chlorine), leading to mechanical failure in the case of external corrosion for the same type of pipe. <u>Yamini and Lence (2010) equate the probability of failure for a given exposure time as a surrogate for the service life of a pipe.</u>

The key purpose of their analyses is to provide useful information to Towns in addressing the planning process for the <u>rehabilitation and replacement</u> of the system infrastructure. Iron pipes placed in a corrosive, more chloride rich, environment can be expected to have a much shorter service life. There is no plan to replace iron casings left in a harsh downhole gas field environment as they corrode. It is only a matter of time before casings corrode away, exposing sheath and plug cement to corrosive attack while opening upward pathways to freshwater aquifers. Thus, the long-term integrity of a plugged and abandoned well has a high probability of failure within less than 100 years – far less time than the life of the aquifer (> 1,000,000 years). The remaining 999,900 years represents 99.99 percent of the approximate life of Delaware River Basin aquifers.

CONCLUSION: The corrosion of casing provides another "weak link" in downhole seals and thus poses a significant water quality and environmental risk.

RECOMMENDATION: The competence of seals in the plugging and abandonment of gas wells should be fully assessed and addressed prior to permitting gas drilling in the Delaware River Basin, or elsewhere.

More on Grout and Casing Failure

The high risk of compromising the integrity of the physical separation of freshwater aquifers from deeper saline water-bearing bedrock formations may be compounded as a result of well grout and casing failures that occur A) as a result of poor well construction (e.g., as in the BP well failure), B) due to mechanisms including cement shrinkage, or C) due to differences in downhole bedrock conditions (e.g., pressure differentials). Zhou et al. (2010) point out that casing pipes in well construction may suddenly buckle inward as their inside and outside hydrostatic pressure difference increases. Dusseault et al. (2000) document the many reasons why oil and gas wells leak, thus providing important supportive scientific rationale as to why both vertical exploratory wells and horizontal gas wells should not be permitted in advance of extensive environmental risk characterization:

> *"Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned (P&A). Explanatory mechanisms include channeling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing.*
>
> *The consequences of cement shrinkage are non-trivial: in North America, there are literally tens of thousands of abandoned, inactive, or active oil and gas wells, including gas storage wells, that currently leak gas to surface. Much of this enters the atmosphere directly, contributing slightly to greenhouse effects. Some of the gas enters shallow aquifers, where traces of sulfurous compounds can render the water non-potable, or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems to come out when taps are turned on."*

Dusseault et al. (2000) detail the underlying causes behind tens of thousands of grout failures in North America that likely compromise environmental security and zonal isolation while leading to contamination of freshwater aquifers. They conclude that:

Surface casings have little effect on gas migration;
Water-cement slurries generally placed at low densities will shrink and will be influenced by elevated pressures and temperatures encountered at depth;
While cement is in an almost liquid, early-set state, massive shrinkage can occur by water expulsion, resulting in shrinkage of the annular cement sheath;
Portland cements continue to shrink after setting and during hardening;
Other processes can lead to cement shrinkage. High salt content formation brines and salt beds lead to osmotic dewatering of typical cement slurries during setting and hardening, resulting in substantial shrinkage;
Dissolved gas, high curing temperatures, and early (flash) set may also lead to shrinkage;
Initiation and growth of a circumferential fracture ("micro-annulus") at the casing-rock interface will not be substantially impeded because cement shrinks;
Circumferential fractures develop and gas leakage typically increase over time;
Wells that experience several pressure cycles are more likely to develop circumferential fractures;
Circumferential fractures propagate vertically upward because of the imbalance between the pressure gradient in the fracture and the stress gradient in the rock;
Free gas will serve to further degrade the casing-grout-rock interface, increase gas flow into circumferential fractures, and may lead to continuous gas leakage;
In turn, differences in pressure favor driving gas, and pressurized fluids present at

depth, upward and outward from circumferential fractures back into bedrock formations (including those present in freshwater aquifers) where the pore pressure is less. Over time, the excess pressure is large enough to fracture even excellent cement bonds and force flow outward into surrounding strata;

Methane from leaking wells into freshwater aquifers is unlikely to attenuate, and the concentration of the gases in shallow aquifers will increase with time;

Loss of this zonal seal can have negative effects, such as pressurizing higher strata, or leakage of brines and formation fluids into shallower strata causing contamination; and

Despite our best efforts, the vagaries of nature and human factors will always contribute to grout failures.

As detailed above by Dusseault et al. (2000), gas leakage up circumferential fractures at the cement-bedrock interface may also enter and degrade freshwater aquifers. In fact, the greatest risk of this occurring is in vertical wells, not in deep horizontal wells that have not been hydraulically fractured (Dusseault et al. 2000). Thus, unfracked vertical exploratory wells pose a greater environmental risk than do deep, unfracked, horizontal boreholes. When the above issues are considered within the broader context of documented regional seismicity, the real threat to the long-term integrity of our freshwater aquifers and quality of our surface waters is obvious.

Structural Integrity and Long-Term Protection of Aquifers

The draft regulations provide no definition of plugging and abandonment with stated goals that set or establish the effective longevity time frame of gas well seals. A time frame (i.e., proven design life) should be established such that structural, chemical, and mechanical qualities of well plugging materials can be assessed relative to the reasonable expected life of overlying freshwater aquifers (i.e., 1 million plus years).

It is critical that the materials and methods used to effect permanent downhole zonal isolation protective of overlying freshwater aquifers can be proven before the integrity of freshwater aquifers is jeopardized. The chemistry of deep gas field horizons may adversely affect freshwater aquifers over time in two different ways. First, there are toxic chemicals and gases associated with hydrofracking operations that can escape upward via wellbores with failed sheaths and fractures (natural or anthropogenically altered). These may adversely affect potable surface and groundwater supplies for a number of generations or more, until such time as they fully biodegrade or are treated with new remedial technologies. Clearly, gas drilling regulations should not be promulgated in the absence of comprehensive chemical biodegradation/chemical half-life information.

The second and more insidious means by which freshwater aquifers may be degraded is via ongoing and very long-term upward excursions of natural gases, hydrocarbons, and deep-seated saline waters that follow a combination of wellbore, fracture, and hydrogeologic pathways. These chemicals will persist in the environment long after hydrofracking chemicals have biodegraded, following flow pathways that were formerly sealed by natural geologic processes over millions of years. The Marcellus shale contains several toxic substances that can be mobilized by drilling. These include lead, arsenic, barium, chromium, uranium, radium, radon, and benzene, along with high levels of sodium chloride (Sumi 2008; Bishop 2010). Of particular concern are chemicals and gases that are lighter than water, including Light Non-Aqueous Phase Liquids (LNAPLs).

Aquifer Loss and Valuation

An important issue that should be addressed prior to issuance of final regulations is that of irreparable harm of natural resources and aquifer valuation relative to the bad precedent of small fines levied against gas companies. Unless there is a substantial reason for gas companies to strictly adhere to all applicable regulations, it is likely that some companies may do what provides the highest profit yields to shareholders, even if this means paying fines. A mechanism should be made part of the regulations that fully places all financial burdens on responsible companies. To aid with this, if gas production from shales is advanced, gas company-specific chemical tracers should be required in all hydrofracking fluids (see discussion below). These tracers should be detectable to the part per trillion level. Should the use of toxic hydrofracking chemicals be permitted within the Delaware River Basin, chemical tracers should, at the very least, be incorporated into all such fluids. Ideally, tracers should be company-specific so responsibility can be properly assigned to those who degraded the finite natural resources of the Delaware River Basin, no matter whether such degradation results from intentional or negligent behavior or an accident or act of God.

Aquifer Purchase

The DRBC regulations should be strengthened to require that gas drillers responsible for contaminating aquifers fully clean them up to the maximum extent possible and develop permanent alternate water supply systems for all adversely affected water supplies. The regulations should also provide for system operation and maintenance costs in perpetuity. Whereas monetary compensation to adversely affected homeowners may be warranted as settlement for inconvenience and health issues, these settlements should in no way remove the responsibility of gas companies to restore the waters of the Basin, as is implied by the words "*otherwise mitigate*" in **Section 7.3(m)(2)**. Provision of whole house water filtration systems should <u>not</u> be an acceptable means of abdicating responsibility and liability. The regulations should be amended to reflect this, thereby insuring that gas companies cannot, in essence, purchase aquifers.

Gas field hydrofracturing has already contaminated freshwater aquifers far removed from production wellheads. In known instances (e.g., Dimock and Springville Townships, PA), there does not appear to be a rigorous response and cleanup effort designed to remediate these aquifers now affected with elevated levels of dissolved methane and/or the presence of combustible gas and other frack related chemicals that may now be present. In fact, the hydrologic damage may already be so great that remediation is impossible. It appears that the oil and gas industry seek to promote a unified front that advances the concept that most if not all contamination of freshwater aquifers must stem from poorly cemented casings or failed sheaths and that the solution is simply to have better control of wellhead activities. While this may be the case in some instances, an equally likely scenario that should be evaluated prior to issuance of draft regulations is that hydrofracturing has opened and interconnected fault and joint pathways between formerly isolated horizons. Under this scenario, what might once have been a localized contaminated groundwater situation is quickly becoming a widespread disaster.

One excellent example of the inherent risk to freshwater aquifers is documented in the Consent Order and Agreement between the Commonwealth of Pennsylvania and the Cabot Oil and Gas Corporation (COP, 2009). Eighteen of 63 homeowner wells near gas wells drilled by Cabot within an adversely affected area now have degraded water supplies (Figure 3). This is some 28.6 percent or almost 3 in 10 wells. This high level of well failures is likely to significantly increase with each success hydrofracturing episode on individual wells, perhaps up to 18 times per well. To date, the affected homeowner wells extend outward to 1,300 feet from Cabot wells, clearly indicating that Cabot's downhole activities has contaminated freshwater aquifers far removed from their individual wellheads. This empirical evidence clearly establishes that the notion that groundwater contamination is limited to areas immediately adjacent to Cabot production wells is not founded on sound hydrogeologic principles. Simply put, freshwater aquifer contamination has occurred, it is likely that gas-rich contaminants are actively spreading and either are or will discharge to surface waters, and that there is little or no effort being made to identify the extent of contamination or to attempt to remediate it. In this Cabot example, only a relatively small fine was levied.

Recent newspaper articles suggest that a four million dollar settlement offer may be being considered by residents and Cabot Oil & Gas in the Dimock, PA groundwater contamination case. Freshwater aquifers should not be considered as water resources that, once contaminated, can essentially be purchased by offending polluters. Groundwater flows in aquifers from upland recharge areas continuously down gradient to such discharge locations as wells, rivers, streams, wetlands, and springs (see Harrison, 1983; Figures 4 and 5 this report). Homeowner wells intercept aquifers at numerous locations within watersheds. Depending on the physical setting, groundwater flow may be shallow or may follow deeper flow vectors (Figure 4). In time, contaminants present in these aquifers are likely to pollute both groundwater and surface water resources far removed from contaminant sources. Thus, these are waters of the Basin and State that require protection in perpetuity.

Dimock, PA provides an excellent, although unfortunate, example of a hydrogeologic flow system that is actively out of control with respect to contaminant migration and permitted well field activities. **The DRBC regulations should clearly state that no new production related activities should be permitted while contaminants are actively moving with the groundwater flow system (i.e., aquifer) to known and undocumented receptors.** Review of Figure 3 shows the approximate location of gas wells in the Dimock, PA area, near where at least 18 homeowner wells have been contaminated by methane and possibly other gas field contaminants. While these wells are not in the DRB, they are in similar geologic formations. The circles represent the approximate distances outward (1000 and 1300 feet) from production wells to contaminated homeowner wells. The pressurized nature of the fractured groundwater flow system near gas production wells is indicated by rapid contaminant transport some 977 feet to the Sautner water well in less than 30 days (Sautner, pers. comm. 4-2-11). Clearly, either the cement sheath installed to protect the freshwater aquifer failed and/or contaminants rapidly moved through deep fractured bedrock strata upward into the overlying freshwater aquifer.

The presence of contaminants in these wells provides clear evidence that gas field contaminants have reached aquifers and are moving with the groundwater flow system. Furthermore, the rapid appearance of methane and other contaminants in wells and other locations (e.g., as seen in methane bubbling in the Susquehanna River) provides evidence that bedrock fractures sometimes provide rapid transport pathways for contaminants – far in excess of slower groundwater velocities in other portions of aquifers. It is only a matter of time before other wells and/or surface water receptors are affected. Until such time as a comprehensive groundwater contaminant investigation, including source assessment, and cleanup are completed, it may not be prudent to continue any gas exploitation in this watershed. Perhaps numerous gas wells are actively contributing to the expansion of one or more contaminant plumes. Perhaps different contaminant plumes are moving in both shallow unconsolidated deposits and in fractured bedrock portions of the aquifer (see Figures 4 and 6). These groundwater contaminant plumes may originate from annular leaks alongside the production casing within the cement sheath. As discussed previously, potential contaminant pathways between the casing and the bedrock are numerous (see Figures 1, 2 and 5).

Regular checking of the Dimock production wells may reveal that there is sustained casing pressure (SCP) that provides evidence of open methane release into the Dimock aquifer. Beyond this contaminant vector, hydrofracking operations may have opened fractures that extend from shale gas horizons upward into the freshwater aquifer. In this case, methane and LNAPL contaminants may be moving directly into the overlying aquifer system at locations far removed from production wellheads. This scenario is far worse than leakage solely up the annulus between the bedrock and the casing as there is no possible means of ever restoring the integrity of the freshwater aquifer by effectively plugging and abandoning vertical production wellbores. Because fracture contaminant pathways may be present above or even far removed from horizontal projections, the regulations should be modified to require testing and monitoring of homeowner wells above and perpendicularly outward from these projections. Figure 6 provides an example of a 2,000 foot buffer area above and extending outward from a horizontal projection array that could be a minimum monitoring distance to establish in revised regulations. Evidence supporting an even greater outward monitoring distance from horizontal projections may be found once the source of methane excursions bubbling up in waterways distant from production wells is established. Morris (pers. comm.) has observed methane bubbling in the Susquehanna River, some three miles from the nearest gas well. Hydrogeologically, this documents an open pathway through fractured bedrock between one or more production wells and the river. Continued bubbling indicates either failure of a cement sheath and/or a direct fracture pathway to the river from a gas-rich shale bed (see Figure 5).

In the Dimock example, contaminants are clearly moving with the groundwater flow system at an undetermined rate. They are in the flow system. The source of the contaminants (i.e., the offending wells or fracture sets) has not been determined and is, apparently, not being adequately investigated. <u>Even plugging and abandoning or somehow correcting failed sheaths on wells will not stop the spread of contaminants already in the groundwater flow system that may take years to adversely affect more homeowner wells and surface waterways.</u> The physical setting must be viewed in its broader hydrogeologic context. It may not be reasonable to permit any future development, and possibly production, in this well field as long as contaminants are spreading further day after day unchecked.

The Dimock example points out a significant flaw in the draft regulations – that gas field operators can potentially negotiate settlement agreements with landowners and regulatory agencies without comprehensively and urgently addressing expanding contaminant plumes. Furthermore, this example well field case exemplifies the need to have criteria in the regulations that preclude daily worsening of contaminant problems. The section further below titled Well Field Closure suggests criteria to be used as the basis of well field closure. Based on the criteria provided, consideration should be given to closing the Dimock well field to production immediately, as the threat to groundwater quality continues unabated.

Bedrock Fracture Connectivity, Pressure Waves and Setbacks

Section 7.5 (b)(4) of the draft regulations provides proposed setback distances from natural gas well pad sites. The regulations do not provide a defensible, rigorous, scientific rationale for such limited distances. The discussion below provides hydrogeologic rationale for amending the setback distances from all water bodies (i.e., wetlands, lakes, streams, rivers, reservoirs), public wells, private wells, and surface water intakes in the DRB from 500 feet to a minimum of 2,000 feet. In addition, a recommendation is made to further assess this distance based on existing well field data before siting new gas wells. For hydrogeologic purposes, the DRBC should consider a well pad to be a roughly rectangular-shaped area that extends upward from the outer boundary of the outermost horizontal projections extending outward from a well pad (see Figure 6). Setback distances should be measured outward from this outer boundary.

Fracture length and interconnectivity are important key factors to consider when seeking to establish safe setback and monitoring distances from gas production wells. Bedrock fractures (i.e., joints, bedding planes, faults) are well documented in parts of the Appalachian Basin (e.g., Jacobi and Smith 2000; Jacobi 2002), especially in New York State. Jacobi (2002) documented Fracture Intensification Domains using a variety of methods, including soil gas anomalies. Many of the mapped fractures extend long distances, sometimes miles. These fractures, and others not identified, represent potential preferential groundwater flow pathways.

Groundwater flow in fractured bedrock aquifers is often anisotropic in nature, meaning that flow may be preferentially oriented along major fracture sets. The best means of assessing natural groundwater flow direction in fractured aquifers is by monitoring water levels and assessing hydraulic gradients in wells completed in the same bedrock units. An understanding of the interconnection of fractures in bedrock aquifers can be obtained by monitoring the hydraulic response of wells at distance from a pumping well. These pumping or aquifer tests are used by hydrogeologists to assess water availability and information about aquifers. Hydrogeologic information gleaned can then be used to delineate hydrologically sensitive recharge areas to protect water quality (e.g., wellhead protection zones).

The draft regulations do not require detailed hydrogeologic testing and assessment to document groundwater flow directions or the fracture interconnectivity of homeowner wells with production wells. In the absence of this information it is difficult to establish that such limited setback distances and monitoring zones in gas fields are scientifically valid and defensible. However, hydrogeologic data does exist in the Delaware River Basin that allows an initial assessment. As part of efforts to locate and prove sufficient water supply for a large proposed project in the East Branch Delaware River Basin, a number of major pumping tests were conducted. As part of the tests, available wells were monitored either using a water level indicator or electronic transducer.

Not all monitoring wells were impacted during the pumping tests, thus documenting the anisotropic nature of the aquifer. Wells that were impacted showed marked decreases in their water levels, followed by water level recovery after cessation of pumping. Distances to wells impacted by pumping in the Delaware River Basin extended outward approximately 1,900 feet. Interestingly, some impacted monitoring wells were in widely different directions from other pumping impacted wells, in two different tests 90 degrees or more apart and 1,000 feet outward from the pumping well. One impacted well was found to be hydraulically connected to the pumping wells by one or more fractures that extend underneath a major tributary of the East Branch Delaware River. The influenced well was high up along a hillslope on the opposite side of the valley. In another nearby pumping test, monitoring wells were impacted by pumping outward to about 1,000 feet. Similar long-distance hydraulic connections were documented during another pumping test just outside the Delaware River Basin (same geology). In this test, water levels in wells were impacted approximately 1,850 feet from the pumping well. These documented distances are to monitoring wells and, as such, do not necessarily reflect the termini of the fractures or take into account other interconnected fractures that may extend further. Recall, also, that Hewitt (1987) documented hydraulic connectivity over a distance of one mile in a gas contamination case outside the Delaware River Basin.

Examination of water level drawdown data in DRB wells impacted by pumping tests shows a very rapid hydraulic response at the maximum distance of about 1,900 feet, even on the opposite side of a major Delaware River tributary. The hydraulic response time in one test, for example, was found to be about 3 hours or less. This time represents the first water level reading after the pumping test was initiated. The response time may have been minutes. It is clear that long distance hydraulic connectivity is present along elongate, interconnected, joints within Delaware River Basin aquifers. Furthermore, it is clear that a hydraulic response within fractures can occur far faster than would be predicted of slow, laminar, groundwater flow. This has important implications for contaminant transport.

Aquifer testing prior to gas well completions should be conducted to test for hydraulic connectivity in the freshwater aquifer between the upper freshwater portion of gas wells and homeowner wells situated within 2,000 feet. This test should be conducted under open hole conditions before the placement of surface casing and a cement sheath, as well as before the well in advanced below the freshwater aquifer. This test will establish the presence or absence of fracture interconnectivity. In addition, if hydraulic connectivity exists, this test will prove that there will be an open, pressurized, contaminant pathway within a time frame of less than one hundred years – coincident with the degradation, corrosion, and failure of the cement sheath, cement plug, and casing. In this event, and because future generations will require potable groundwater, the incipient gas well should be completed as a freshwater well for future residential or farm use.

Hydraulic fracturing applies great downhole pressure that seeks release wherever possible. Thus, if a hydraulically open pathway exists in the form of bedrock fractures and/or through a poorly sealed and failed cement sheath, it is possible that a transient pressure wave or pulse may rapidly transmit through fractures intersected by a homeowner well. Depending on a number of factors including fracture aperture and frictional resistance, the sudden increase in pressure may be exerted on fluid-filled fracture or annular pathways that connect to homeowner wells. Because water is an incompressible fluid (some 100 times less compressible than steel), if the pathways are sufficiently open, a sudden increase in pressure may be transmitted as a pressure wave due to a sudden change of direction or velocity of the fluid (Hammer 1991). If the system through which the pressure wave is transmitted is sufficiently open, the velocity of the pressure wave will be equal to the speed of sound. If fractures are not sufficiently open, the increase in pressure may still be observable in monitoring wells as a time lagged response. In keeping with this sudden increase in pressure, it is likely that pressure will be released in all available directions, even against the local groundwater flow direction. In wells, this increased pressure may result in a local rise in water table within the aquifer. The rise in water level would subside as the pressure wave diminishes. High pressures may also serve to further open pre-existing pathways.

Transducers should be placed in homeowner wells to monitor water level/pressure changes during gas well construction, stimulation and development. They should be installed prior to well spudding and should be required throughout the productive life of gas wells. They should be programmed for a time interval considerably shorter than the minimum duration of fracking events, as a pressure wave may rapidly impact homeowner wells that are open to the outside atmosphere where pressure (and gases) may readily be released at well heads. A hydraulic response will directly equate to hydraulic connectivity between a production well and joints, bedding planes, and/or faults intersected by homeowner wells. A hydraulic response observed in a homeowner well during and/or immediately following a fracking event will document either a failed cement sheath and/or a fracture connection to open downhole pressurized horizons. As is the case with tracer testing, multiple tests are not needed to prove a hydraulic connection – once is enough. The pathway between the production well and the freshwater aquifer either exists or it doesn't. This real-time hydraulic response, should it occur, would provide cause to 1) first re-grout the annulus or 2) if observed again on a second fracking operation, plug and abandon the production well. Convenient transducer equipment failure during fracking events should be cause for well closure.

It is important to point out that a lack of water level or pressure response in a homeowner well during or following a fracking event does not necessarily confirm that no hydraulic connection exists. It may simply be that the pathways are sufficiently narrow, such that slow, laminar, groundwater flow is the only possible means of contaminant transport. The value of installing transducers in homeowner wells prior to gas field activities lies in firmly establishing baseline conditions and in being prepared should a hydraulic connection be open during fracturing events. If, for example, the Sautner well in Dimock, PA had a transducer installed in it during the onset of hydraulic fracturing operations, it is quite likely that a response would have been recorded, thereby potentially proving their contaminant case instantly. This would in turn have negated the need for major legal costs and would have provided regulators with cause to require timely well repairs, assuming that a hydraulic response was registered. Of course, the hydraulic connection, if observed as proposed here, would have allowed for preventative action to be taken that could have avoided contamination of this homeowner's well and may have provided information that could have prevented the large-scale aquifer contamination that is well-documented by PADEP in Dimock, PA.

It is important that a safe setback distance be established outward from horizontal projections to protect streams, rivers, reservoirs, and surface water bodies and that horizontal drilling and hydraulic fracturing not be allowed under these water bodies for the same reasons. The pumping test data discussed above provides justification for a minimum distance of 2,000 feet. This distance is further justified based on the fact that contamination of freshwater aquifers has occurred in Appalachian Basin gas fields. **Further examination of existing production and homeowner well data, as well as other aquifer test results, may provide rationale to extend this distance farther.**

Numerous homeowner wells in nearby Dimock, PA (also in the Appalachian Basin) show contamination outward from gas production wells to at least 1,300 feet. However, the north-south alignment of some of these wells (Figure 3) may indicate a common fracture network extending for miles. This well alignment may correlate with Jacobi's prominent J2 joint orientations documented throughout the Appalachian Basin. Considering that gas well contamination moved 977 feet to the Sautner well in less than 30 days (Sautner, pers. comm.), an extremely rapid groundwater flow velocity is indicated (> 32 ft/day). In fact, depending on how open fractures are between the nearest production well and the Sautner well, it is possible that the first wave of contamination impacted their well at the speed of sound. Had a transducer been in place, this could potentially have been documented. If appropriate testing had been done prior to gas well construction, the contamination may have been avoided. Similarly, methane bubbles issuing from beneath the Susquehanna River, about 3 miles from the nearest gas production well (Morris, pers. comm.), may provide justification for a longer set-back distance from underlying horizontal projections. Fractures extending beneath water bodies pose a great water quality and ecologic risk should upward methane and other contaminant excursions occur.

Conclusion: Hydraulic fracturing generated pressure waves may be an important hydrologic tool for assessing the lack of zonal isolation. **In addition, pumping tests conducted in advance of deep gas well drilling can provide an important means of preventing homeowner well contamination by not allowing gas well installations along hydraulically connected fractures where contamination is assured coincident with short-term grout and/or casing failure**. All homeowner wells within the monitoring zone should be fitted with transducers programmed to record in time increments of shorter duration than the duration of fracking events. Homeowners should be notified 48 hours in advance of all hydraulic fracturing events. Aquifer testing prior to gas well development is a tool that should be used to help identify hydraulic connectivity.

Homeowner Monitoring Well Recommendations: All homeowner wells above the boundary outline area of horizontal projection arrays and extending outward an additional 2,000 feet (see Figure 6) should be fitted with transducers before production wells are spudded and thoughout the life of the well, continuing for at least one year following plugging and abandonment. A pumping test should be conducted before completion of gas wells to establish the presence or absence of hydraulic connectivity with homeowner wells. If a connection is found, incipient gas wells should be completed as freshwater wells and turned over to landowners.

Transducer data should be reviewed after each fracking event and at three month intervals. Additional hydrogeologic analysis of distances to adversely impacted homeowner wells and new methane seeps, beyond what is presented in this report section, should be conducted before additional gas wells are installed. This will allow refinement of the 2,000 foot homeowner monitoring well zone distance. Regulations should have a caveat to allow for extending the monitoring zone beyond 2,000 feet based on new findings. <u>See additional detail regarding recommended step-drawdown testing in the bulleted section above.</u>

Gas Well Buffer Distance Recommendation: Based on the above discussion that provides documentation that fractures extend beneath surface valleys and to distances of at least 2,000 feet, the regulations should prohibit gas well projections within a minimum of 2,000 feet from all surface water supply intakes, reservoirs, lakes, wetlands, major streams, and rivers and expressly prohibit drilling and hydraulic fracturing under water bodies. Upward escaping methane and other contaminants that leak into these water bodies may irreparably harm them.

Love Canal Pales in Comparison to Risk to Water Quality in Gas Fields

The draft DRBC regulations are cursory in that they focus more on daily well permitting and regulatory matters without the benefit of having taken a "hard look" of the potential widespread and long-term aquifer degradation that will almost assuredly result if the regulations are promulgated as is. Gas field contaminants that compromise the quality of freshwater aquifers should be viewed in much the same way as wastes that may have been dumped out the back door of an industrial facility or stockpiled in a landfill, such as the Cortese landfill near the banks of the Delaware River. Hydrogeologically, individual waste sites such as Love Canal (i.e., one of the worst hazardous waste sites in the United States) or the Cortese Landfill are far easier to characterize and remediate or contain than gas wells because they have finite boundaries vs. a relatively closely spaced network of potentially leaking boreholes and interconnected fractures throughout an enormous watershed area. Unlike Love Canal and other waste sites, contaminant excursions from a tightly gridded gas well network are insidious in nature because the extent of their source areas cannot readily be viewed or delineated on the ground surface, their distribution is expansive throughout much a huge watershed area, contaminant impacts are likely to be cumulative in nature, the full extent of contamination is not likely to be known for many decades although drinking water contamination can occur immediately and catastrophically, and the greater percent of zonal hydraulic seals designed to protect overlying freshwater aquifers are not likely to fail until after the close-out financial terms of the DRBC regulations have long since expired.

From a hydrogeologic standpoint, in the absence of high quality and permanently effective zonal isolation of deep gas horizons, it would be far preferable to characterize and remediate a number of Love Canal like contaminant sites in the Delaware River Basin than to attempt to address an insidious, widespread, contaminant problem underground. We are already seeing the tip of the iceberg relative to gas field degradation of freshwater aquifers in Dimock, PA and in many other gas fields. Because the technology does not currently exist to guarantee permanent (i.e., > 1,000,000 years) zonal isolation and water quality protection between gas horizons and freshwater aquifers, consideration should be given prior to promulgation of the DRBC regulations to placing them on hold until after the gas industry can demonstrate very long term aquifer protection. **Additions should be made to the regulations that require gas companies to document and demonstrate exactly how the hydraulic integrity of freshwater aquifers will be maintained in perpetuity before any additional gas exploration and production are permitted.**

The contamination of each homeowner well close to a gas well should be viewed and treated as individual contaminant spills. In each case, hydrogeologic and chemical testing should be conducted to determine the source and composition of the contaminants present, to fully delineate the areal and vertical extent of the contaminants, and to assess likely down gradient receptors. Once determined, if possible, contaminant source removal should be undertaken, followed with comprehensive aquifer remediation and restoration. This may be very expensive and may not be possible in anisotropic fractured bedrock aquifers of the Delaware River Basin. If aquifer restoration is not deemed possible, consideration should be given to establishing this as a trigger to immediately and permanently close down all gas wells with vertical and horizontal components situated up gradient of contaminated homeowner wells.

Aquifers are irreplaceable. They need to be available, untainted, for public use for the next million years. It would be a most unfortunate precedent to permit gas companies to "purchase" aquifers in settlement agreements for a very small percentage of the profits likely to be reaped from just one production well. Consideration could be given to establishing a fund analogous to that agreed to by British Petroleum, such that contaminant cleanup can be conducted and alternate water supplies can be identified and brought in from distant, untainted, sources. Prior to permitting gas wells, well-researched contaminant response and aquifer replacement plans (complete with financial accountability) should be in place. Otherwise, it is unlikely that there will be a large enough public outcry, as in the recent BP well failure, to achieve the needed response.

Sponsor-Specific Drilling Fluid Tracers

The draft DRBC regulations provide no means of positively identifying project sponsors (i.e., gas drilling companies) in the event of contaminant issues. Proving the connectivity between oil and gas drilling operations and critical water supplies is essential in understanding, detecting, and mitigating undesirable events associated with oil and gas drilling operations and production operations. A Bureau of Land Management pilot study was initiated in 2005 in southeastern New Mexico carbonates where oil and gas drilling operations are required to put tracer dyes into their drilling fluids before they start drilling and then again before they case and cement the wellbore (Goodbar 2009). The subsequent discovery of assorted dyes (Eosine Y, Rhodamine WT, Fluorescein [acid-yellow-73]) in groundwater confirmed that contaminants entered groundwater through drilling and cementing operations or during later phases of production. Following the addition of tracers during new well installations, significant (to over an order of magnitude) tracer detection was found in wells and springs, documenting hydrologic connectivity and the risk to groundwater resources (Goodbar, pers. comm.). The study also identified a number of procedural and dye concentration issues that are being improved upon. While this study was conducted in carbonate bedrock, it points out the successful utility of using tracers to identify drilling fluid related contaminant sources and their related production companies. Sponsor-specific tracers should be required in the regulations. Tracer selection, concentrations, mixing, injection, and monitoring should be sub-contracted to experienced tracer experts.

Required Use of Non-Toxic Hydrofrack Chemicals

The draft DRBC regulations should be amended to allow only the use of non-toxic and non-carcinogenic substances and materials in the downhole environment. The regulations must be revised to ensure long-term aquifer protection before permitting gas drilling. The draft DRBC regulations will establish a mechanism to issue permits for gas wells but fail to set up a protective mechanism to ensure that failed or poorly constructed gas wells, as well as gas well accidents, do not result in the degradation of aquifer water quality throughout the Delaware River Basin. To protect fresh water resources, the regulations should forbid the use of toxic and carcinogenic chemicals in well construction and operation processes. As the draft regulations now stand, natural geologic barriers that took millions of years to form, including confining beds protective of freshwater aquifers, will be breached by thousands of gas wells that will create open contaminant vectors that will persist for hundreds of thousands of years after cement plugs and casings degrade and fail in less than 100 years. In essence, natural hydraulic barriers that isolate and protect freshwater aquifers from underlying saline water and assorted natural contaminants will be weakened or destroyed within a few decades. And in some instances, such breaches can occur quickly, as is demonstrated by the case of Dimock discussed above.

Industry experts acknowledge the risks to water quality. Work is actively being conducted to reduce or eliminate the use of toxic chemicals. Rae et al. (2002), for example, address numerous advances toward this end, acknowledging that some of the "*materials used are toxic and some may not biodegrade at acceptable rates*." In discussing the need to develop more efficient, less toxic alternatives, they state:

> *" As an industry, we have been actively pursuing this goal since the early 1960's, replacing many additives with environmentally-friendly alternatives. However, in many cases, the pace of progress is too slow and, too often, were it not for pressure from environmental groups, government legislation or commercial advantage, our industry would go on using the same old toxic additives for years. With few exceptions, a little ingenuity can help replace many of the older and more toxic materials and practices with safer, more environmentally friendly alternatives. ... Many production chemical*

companies are indeed working to replace some of the more toxic or non-biodegradable components of their additives with "green" alternatives. The obvious things to remove have included the aromatic solvents and suchlike. ... Protection of the environment by the use of non-toxic, biodegradable or non-bioaccumulating chemicals is essential not just for our benefit but for that of our children and grandchildren. The industry must embrace a policy of striving to anticipate and exceed any standards laid down in future environmental legislation."

Numerous other gas industry experts acknowledge the risk of contaminating freshwater aquifers, thereby accenting the need to avoid use of toxic chemicals. Brufatto et al. (2003), for example, state:

"Despite these advances, many of today's wells are at risk. Failure to isolate sources of hydrocarbon either early in the well-construction process or long after production begins has resulted in abnormally pressurized casing strings and leaks of gas into zones that would otherwise not be gas-bearing. ... Even a flawless primary cement job can be damaged by rig operations or well activities occurring after the cement has set."

Clearly, the petroleum industry believes that gas well production can be achieved without the use of toxic chemicals. <u>The DRBC draft regulations should be revised to preclude the use of toxic chemicals in gas well construction and operation.</u> In addition, gas companies that seek to use toxic chemicals that place freshwater aquifers at risk should be denied permits. Until such time as standards for safe and non-toxic chemicals and additives to be used in well construction and operation can be established and detailed in the regulations, the regulations should not be promulgated.

Hydrofracking Related Chemicals

Should the DRBC decide to allow gas companies to use toxic chemicals in the gas field, it should refrain from issuing the final regulations until such time as the public has had an opportunity to learn and comment upon all hydrofracturing chemicals that will be used.

The draft regulations require a Post Hydraulic Fracturing Report that lists *" ... the volume and amounts of all chemicals and additives used during the hydraulic fracturing of a natural gas well.*" At first glance, knowledge of the exact composition of toxic hydrofracking chemicals might not appear to be critical. However, because adverse health impacts may result from exposure via ingestion or inhalation of these chemicals, it is critical that they be disclosed to the public in advance of their use.

Importantly, from the public health, medical and water quality standpoints, it would be best to permit only the use of non-toxic drilling muds and hydrofracturing fluids, should hydrofracturing of gas-rich shales be permitted. Much discussion has focused on getting gas companies to disclose each and every hazardous, carcinogenic, and toxic chemical used in the hydrofracturing process. Ultimately, if a chemical soup of toxic substances is permitted for use in hydrofracturing, from the standpoint of water potability public disclosure of the total number and specific name and toxicity of each doesn't solve the problem of the introduction of these chemicals into the environment. Hydrologically, however, their densities and solubilities are of importance relative to their movement potential in groundwater. Should this chemical soup mix with freshwater aquifers, it is likely to result in medical problems if ingested. The presence of hydrofrack chemicals in potable freshwater aquifers will essentially make the water unsuitable for drinking, in perpetuity. In many rural areas without centralized water supply systems or areas without large base flows in surface waterways, groundwater presents the only viable water supply source. The DRBC must examine this key issue before final regulations are issued and ensure that the chemical mixtures used are disclosed and regulated to ensure drinking water protection.

Two other very important issues are 1) whether there is a combination of fracking fluids and drilling muds that can be used that are non-toxic as discussed above, and 2) whether the use of hazardous and toxic fracking fluids provides sufficiently greater gas productivity compared to historic non-toxic drilling mud and sand hydrofracturing methods to warrant such use at all. If, for example, gas productivity obtained via the use of toxic chemicals is only 20 percent greater than using non-toxic well development methods, then it may make sense from an environmental risk standpoint to prohibit the use of any toxic fluids. Importantly, the combined risk of seismic hazards, whether natural or anthropogenic, and grout failure pose a real risk of aquifer contamination from methane – even in the absence of hydrofracking chemicals. Even if hydraulic fracturing could be conducted without the use of any toxic chemicals, the increased presence of methane, radon, and radium-226 in freshwater aquifers presents an increased water and air quality exposure risk. These factors should be carefully weighed prior to issuance of regulations.

Seismic Hazards

The Delaware River basin is a seismically active region of the United States. Gas well boreholes and casing strings, even if grouted and/or plugged with the best available concrete materials available today, have a high probability of being compromised in response to earthquakes. This may lead to loss of zonal isolation and contamination of freshwater aquifers.

The regulations should be amended to include practical well field planning, based on a seismic risk study of the Basin, which minimizes risk to freshwater quality. In addition, seismic assessment and monitoring should be incorporated as a regulatory requirement to assess rock deformation and fracture locations. Prior to the DRBC gas drilling regulations being promulgated, it would be prudent to first examine the environmental risks to freshwater aquifers should natural or gas well-induced seismicity compromise well integrity by degrading zonal hydraulic seals or deforming or shearing well casings. Industry experts (e.g., Daneshy 2005) recognize that even the creation and presence of hydraulic fractures can cause casing failure both during and after fracturing operations. Casing failure is known to occur while fracturing and during well production. The risks to water resources from casing failure due to seismic activity as well as from casing failure due to fracturing operations themselves must be comprehensively analyzed with an opportunity for public review and comment before any final regulations are promulgated. The decision to permit gas well installations should be founded on sound science that has had the full benefit of public review and comment. With long-term water quality and aquifer integrity as the goal, I recommend that a Draft Environmental Impact Statement and/or Cumulative Impact Analysis be required as a precursor to further consideration of the draft regulations.

The Delaware River Basin (Figure 7) is in an area of our country that is seismically active. Rubin (2010) addressed this hazardous physical setting. Figures 8, 9, and 10 show the DRB and surrounding area have historically been affected by numerous earthquakes. Figure 11 illustrates peak acceleration with 2 percent probability of exceedance in 50 years for DRB states as determined by the USGS National Seismic Hazard Mapping Project. **DCNR (2006) states that it is entirely possible that an earthquake of magnitude 6 or greater will affect the DRB at some point in time.** Predictive model results derived using the USGS National Hazard Mapping Project model [URL: https://geohazards.usgs.gov/eqprob/2009/index.php] (Figures 12 and 13) show that there is a 4 to 8 percent chance that a magnitude 5 or greater earthquake will affect the DRB within 100 years and a 20 to 25 percent chance that a magnitude 5 or greater earthquake will affect the DRB within 500 years.

While the predictive assessments discussed above for 100-year and 500-year magnitude 5 earthquakes may initially seem like long time periods, they are not. As did civilizations that developed long ago, we anticipate that our modern civilization will continue far into the future with no end in sight. Our earliest civilizations date back many thousands of years. For example, Mesopotamia, situated between the Tigris and Euphrates rivers, had urban societies during the Ubaid period (ca 5300 BC). Earlier settlement has been documented at least as far back as the Neolithic Boreal Period (ca 7200 BC). Egyptian civilization coalesced along the Nile River around 3150 BC under the first pharaoh. Humankind has evolved over a number of million years to our current form and should continue to prosper over the next one million plus years.

Thus, while our society along the Delaware River is still young, we should reasonably plan on preserving and protecting our natural resources for the next million years. In keeping with the Mesopotamian civilization and projecting into the future, it is not a stretch to assess potential seismic risk for 10,000 years. Using Philadelphia as an example, the USGS National Hazard Mapping Project model predicts that there is a 60 to 80 percent probability that a magnitude 6 earthquake will occur within the Delaware River Basin in the next 10,000 years (Figure 14). While it is true that the initial earthquake data set used to make this prediction is based on data from a limited time period, it is highly likely that, over significant-enough periods, even larger earthquakes will occur in the DRB. In the long-term, it is not a question of will a magnitude 6 or greater earthquake occur in the DRB, but rather one of when. Clearly, the draft gas drilling regulations should be preceded by both a seismic risk assessment that examines the risk of casing shearing and an assessment of the long-term integrity of well field zonal isolation materials. The materials in use now do not have a proven long-term design life and are likely to succumb to the well failure mechanisms addressed in this report.

It is not hard to imagine the potentially disastrous effects that small and large-magnitude earthquakes might have in a seismically active region, such as the DRB, with hundreds and thousands of fragile well casings and brittle cement sheaths separating irreplaceable freshwater aquifers from deep, contaminant-laden, horizons. Statistically, the probability that instantaneous and catastrophic shearing of casings and/or fracturing of cement sheaths will occur during seismic events is great. Unlike the recent British Petroleum well failure in the Gulf of Mexico where oil quickly surfaced, many well field contaminants might go undetected for years during which time significant aquifer degradation may occur. The tight density of well placements planned in the DRB would surely exacerbate this contaminant risk scenario. Once freshwater aquifers are both chemically degraded and hydraulically commingled with deep connate waters, the likelihood of ever restoring them is negligible.

Perhaps it may be easier to envision the sudden, catastrophic, risk to multiple well casings and cement sheaths in the recent aftermath of the 6.3 magnitude earthquake that occurred near Christchurch, New Zealand (see Figure 15). Figure 15 illustrates likely methane and LNAPL pathways along fault planes, bedding plane partings, joints, and well annular spaces. In New Zealand, hundreds of buildings collapsed, pipes burst, bridges were damaged, and sidewalks and roads were cracked, split, and lifted as much as one meter. Repair costs are estimated at sixteen billion dollars. Clearly, the structural damage to the earth associated with a quake of this magnitude, which is entirely possible in the Delaware River Basin, could in moments result in great and irreversible damage to freshwater aquifers riddled with deep gas wells laced with toxic chemicals.

Bruno (2001) details some of the mechanisms whereby bedding plane slip and casing shear damage has occurred, resulting in damage to hundreds of oil and gas wells throughout the world. Some of these mechanisms are likely to be exacerbated via natural or anthropogenically-induced seismic activity. An example of fault sheared bedrock and gas well casings, such as that which might occur in the Delaware River Basin, is depicted on Figure 15. Figure 16 clearly illustrates that faults in seismically active regions do break the ground surface and can result in significant displacement, as can faults that do not visibly result in earth offsets. Even one significant earthquake has the real potential of catastrophically shearing hundreds or thousands of casings in moments.

Chanpura and Germanovich (2001) discuss field examples where gas production has induced massive and significant casing damage, well failures, and major earthquakes with associated fault movement. One example they discuss is as follows:

> *"Probably the most studied example of extraction-induced seismicity is that of the Lacq (France) gas field where seismic events have been continuously monitored for more than 25 years [e.g., Grasso and Wittlinger, 1990; Lahaie et al., 1998]. The largest reported deep seismic events, triggered by gas extraction, are three major earthquakes (with M = 7) near the Gazli gas field, Uzbekistan, in 1976-1984 [e.g., Simpson and Leith, 1985; Amorése and Grasso, 1996]."*

Bruno (2001) found that "*Reservoir compaction and associated bedding plane slip and overburden shear has induced damage to hundreds of wells in oil and gas fields throughout the world.*" Gas extraction and repeated hydrofracturing events pose a risk to the structural integrity of well casings and cement sheaths, especially in high density plays such as that of the Delaware River basin. Once casings are sheared or sheaths compromised, upward contaminant excursion into freshwater aquifers is assured. <u>More detail specific to earthquakes, seismicity, and well</u>

failure is provided in attached Addenda 2, 3, and in the section entitled "More Detail on Earthquakes, Seismicity, and Risk of Casing Shearing".

Irreparable degradation of freshwater aquifers resulting from seismic activity (natural or induced) should be weighed against short-term energy gain as part of a risk-benefit assessment before regulations are finalized. This assessment should be conducted as part of an Environmental Impact Statement, open for public review and comment.

In addition, the draft DRBC regulations should be amended to include the use of tiltmeters (Arthur et al. 2009) and other appropriate seismic instrumentation. Micro-seismic imaging, for example, may be a useful downhole technology that could be used to identify and then avoid hydrofracking proximal to faults (Maxwell et al. 2007).

More Detail on Earthquakes, Seismicity, and Risk of Casing Shearing

The installation of exploratory and hydrofractured wells that open borehole or nearby joint pathways between formerly separated geologic horizons pose an environmental risk, particularly because the Delaware River Basin is seismically active. Ground motion associated with seismic activity has the real potential of instantly shearing multiple well casings, degrading cement grout designed to isolate geologic horizons, and thereby opening vertical joint and borehole vectors between formerly separated geologic horizons. Numerous earthquakes have occurred in Pennsylvania, New York, and adjacent states (see Addendum 2 and Addendum 3), pointing out that the region of the exploratory wells is seismically active. Figure 10 depicts historical earthquake epicenters, documenting that significant portions of the Appalachian Basin are seismically active. Figure 11 portrays USGS seismic hazard maps for Pennsylvania, New York, Delaware, and New Jersey. The Wayne County, PA area shows a peak horizontal ground acceleration of some 6-8% g with a 2% probability of exceedance in 50 years (i.e., earthquake ground motions that have a common given probability of being exceeded in 50 years). The %g relates to the acceleration due to gravity. It is a measure of ground motion that decreases the farther one is from an earthquake epicenter. A 6-8%g roughly correlates with a Modified Mercalli Intensity of VI. This intensity of an earthquake is likely to be felt by everyone, may result in movement of heavy furniture, and may damage house plaster and chimneys (DCNR, 2006). While damage on the ground surface is slight, it is likely that damage to cement sheaths and possibly well casings may occur – potentially compromising the integrity and physical isolation of different bedrock horizons.

Seismic activity beyond and in Pennsylvania may result in sufficient ground motions that may compromise the integrity of cement sheaths and well casings. This, in turn, may result in interformational mixing of groundwater along exploratory well boreholes, hydrofracked wells, or adjacent joints (see Figure 15). Earthquakes have occurred in Pennsylvania and elsewhere (DCNR, 2006). One of the largest earthquakes in this region, of unknown magnitude, had an epicenter near Attica, NY and is reported to have cracked walls in Sayre, PA in 1929. Sayre is located in Bradford County, only 50 miles from Wayne County. Another nearby New York State earthquake, with a magnitude of 5.5, occurred in New York City in 1884, again documenting that the region is seismically active.

Numerous earthquakes have occurred in Pennsylvania, many in recent time, with the largest recorded in 1998 with a magnitude of 5.2. For example, some of those reasonably close to Wayne County include Berks County (to magnitude 4.0 and 4.6 in 1994), Bucks County (to 2.5), Lancaster County (to 4.4), Lehigh County (to 3.3), Monroe County (immediately south of Wayne County; 3.4, epicenter may have been in NJ), and Montgomery County (3.5). While these earthquakes did not produce substantial damage, there is a reasonable probability that higher magnitude earthquakes, with related damage, may occur. DCNR (2006) details this real possibility:

> *"Earthquakes having magnitudes greater than 5 can occur in Pennsylvania, as demonstrated by the earthquake of September 25, 1998 (Armbruster and others, 1998) (Table 2, Crawford County). Southeastern Pennsylvania, the state's most seismically active region, is not known to have experienced an earthquake with magnitude greater than 4.7, but the historical record goes back only about 200 years. No obvious reason exists to conclude that an earthquake of magnitude between 5 and 6 could not occur there also. An earthquake with magnitude greater than 6 is much less likely, but the fact that such large earthquakes have occurred elsewhere in the East means that this possibility cannot be ruled out entirely for Pennsylvania. ... The possibility that a magnitude 7 earthquake could occur having an epicenter near New York City cannot be completely discounted, and such an earthquake could produce significant damage (intensity VIII) in eastern Pennsylvania. ... A large local earthquake, one with magnitude greater than 6, though unlikely, is not impossible."*

Earthquakes of these magnitudes in Pennsylvania have the real potential of resulting in sufficient ground motion to shear well casings and degrade the integrity of grout designed to physically separate different geologic and hydrologic horizons. For example, earthquakes of magnitude 5.0 to 5.9 on the Richter or moment magnitude scales can cause major damage to poorly constructed buildings. Wikipedia provides an approximate energy equivalent in terms of TNT explosive force for a 5.0 Richter magnitude earthquake as being equivalent to the seismic yield of the Nagasaki atomic bomb. Clearly, the decision to permit installation of exploratory wells, or horizontal wells, should be based on a comprehensive analysis of all environmental risks. It should be noted that the risk to grout and casing integrity exists both from natural earthquake activity and, in the case of hydraulically fractured horizontal wells, from micro-earthquakes stemming from fluid-induced seismicity (Bame and Fehler 1986; LI 1996; Feng and Lees 1998; Horálek et al. 2009; Shapiro and Dinske 2009). Therefore, the potential impacts of seismicity, whether from natural or man-induced activities, should be extensively analyzed prior to any deep drilling efforts or promulgation of drilling regulations. Because portions of Pennsylvania are seismically active, a real risk exists that earthquakes might instantly and catastrophically degrade grout integrity and shear multiple well casings, resulting in the commingling of formation fluids and release of methane. Unlike the recent British Petroleum disaster in the Gulf of Mexico, once the integrity of bedrock formations is breached, it will not be possible to restore degraded freshwater aquifers.

As an example of active seismicity in the Appalachian Basin, Jacobi and Smith (2000) document the epicenters of three seismic events in eastern Otsego County, New York. These seismic events indicate that earth movement occurs from great depth along faults upward to aquifers and near the ground surface. The great lateral extent of these faults, and their visually observable connectivity with other faults, confirms that the process of hydraulic fracturing, which may interconnect naturally occurring faults and fractures, has a great and very real potential of causing contaminants to migrate to aquifers and surface water from localized zones across and beyond county and watershed boundaries.

Well Field Closure

While the draft DRBC regulations do address the issue of specific well problems in part, they do not contemplate or provide specific threshold criteria for the permanent closure of well fields in the event of evidence that aquifer water quality is at significant risk. The cease operations authority of the Executive Director [**Section 7.3(n)**] is not sufficiently detailed. This authority should be made more comprehensive by including well-field cease operations criteria.

It is important to recognize that the presence of hundreds and thousands of wellbores that breach geologic confining beds pose significant hydrogeologic risk to overlying freshwater aquifers. For reasons discussed in this report, by Rubin (2010), and by many industry experts referenced at the end of this report, as well as many others, it should be clear that the mix of industry practice and complex geology have the real potential of getting out of control. To minimize additional long-term risk to aquifer water quality, the prudent course of action may be to permanently close both individual gas wells and entire well fields. Criteria should be developed and incorporated into the regulations that trigger well field closure. Some of these include:

- Sudden hydraulic or water quality response of homeowner wells to hydraulic fracturing operations that demonstrate a link between deep and shallow fracture systems. This response might, for example, be recorded as a rapid change in water level or pressure in a homeowner well coincident with a hydrofracking event;

- Presence of any contaminated homeowner wells within or near a well field. As methane enters and accumulates in freshwater aquifers, it will move down gradient of its initial release avenues until an open release pathway is encountered (e.g., open joints). The presence of methane and/or other gas field contaminants in homeowner wells coincident with gas production indicates the presence of an actively functioning hydraulic link between freshwater aquifers and either 1) a failed annular seal in a gas well, or 2) hydrofracked fractures that extend upward into an overlying aquifer. The presence of these contaminants also provides evidence that contaminants are actively moving unchecked down gradient with the groundwater flow system to other receptors (e.g., homeowner wells, streams, springs, wetlands, lakes). The section entitled "Bedrock Fracture Connectivity, Pressure Waves and Setbacks" provides documentation of bedrock fracture connectivity, hydraulic fracturing induced pressure waves, hydrogeologic rationale for homeowner well monitoring zones, and justification for a 2,000 foot setback from water bodies;

- Unchecked and spreading aquifer contamination that is not being actively investigated and remediated via systematic hydrogeologic investigation;

- Gaseous excursions to land or homeowner wells, homes, or outbuildings via groundwater pathways that have or may trigger explosions (e.g., methane release, gurgling in homeowner wells);

- Evidence of spills, accidents, leaks, etc. related to gas wells, tanks, well infrastructure and related equipment;

- Demonstrated water and/or air quality impacts to caves and mines;

- Sponsor-specific tracer detection in freshwater aquifers;

- Repeated buildup of a measurable sustained casing-head pressure (SCP) in gas wells. The presence of SCP at the casing-head of a casing annulus that rebuilds when bled down, when not caused solely by temperature fluctuations, is an indication of an existing poor annular seal. Repeated SCP is an indication that methane and perhaps other contaminants may be freely entering aquifers. For example, methane excursions seen continuously bubbling up in streams miles from the nearest gas wellhead (David Morris, pers. comm.) may provide evidence of failed annular cement integrity and ongoing aquifer contamination;

- Gaseous excursions to surface waters or surface water features (e.g., bubbling in surface waterways, wetlands or vernal pools);

- Presence of airborne contaminants that have affected or may adversely affect human health or the environment (e.g., volatile organics);

- Destructive seismic activity within or near a well field;

- Improperly maintained and/or leaking gas production wells. The section entitled “Additional Life of Concrete Material – Plus Life of Steel” provides additional documentation on the life of concrete and steel in the downhole environment;

- Contamination of surface waters by gas field contaminants;

- Fish and other biota kills associated with gas field chemicals;

- Sudden sickness and/or death of nearby homeowner animals, as well as other animal mortality (e.g., rabbits, deer, birds, frogs, fish);

- Too lengthy contaminant investigation and response time;

- Human health issues associated with gas field activities; and.

- Secret, non-disclosure, property buy-out, or settlement agreements between a project sponsor and private landowners that result in any lack of transparency regarding surface water, groundwater, and/or airborne contaminants and knowledge of their full environmental and health impacts.

Plugging Regulations & Iron Pipes – Another Weak Link in Plugged & Abandoned Well Integrity

Operators routinely remove production casing from wells when their productive life ends. Plugging regulations in the State of Pennsylvania (e.g., 1989; §78.91), for example, call for installation of a 50-foot plug of cement at the attainable bottom when the well's total depth is not reachable. Above this, other gas-bearing formations must also be grouted, but much of the borehole may be left non-cemented until 100 feet below the surface casing. While PA regulations (e.g., 1989; §78.95) require filling with "*nonporous*" and "*noncementing*" materials, it is not clear what these materials are or what their permeability and corrosivity properties are.

In some cases in the Delaware River Basin, production casing cannot be or is not removed from the downhole environment prior to well abandonment, thus potentially providing another vector for upward contaminant movement to freshwater aquifers and homes when casing degradation and plug failure occur. If the production casing cannot be retrieved, the well operator must plug the gas-bearing strata by perforating the casing and squeezing cement into the annulus. The operator may then leave the annulus above the gas-bearing strata non-cemented for thousands of feet, open for gas excursion when plug failure occurs (i.e., in less than 100 years) until a point some 100 feet below surface casing where more cement is required to protect overlying freshwater aquifers (State of PA 1989). In addition, the operator must also cement off any other strata that may be gas bearing, if present. Thus, only part of the borehole is sealed with cement, thereby reducing much protective cement that could be placed if cost were not a factor.

CONCLUSION: The existing plugging regulations in Pennsylvania are long outdated. In light of the known and demonstrated threat of groundwater contamination from failed cement sheaths and repeated episodes of high pressure hydraulic fracturing, plugging regulations throughout the Delaware River Basin should be uniformly reviewed and revised.

Extensive literature documents that the Portland cement typically used in gas wells is brittle, has low tensile strength, and is not durable under cyclic stress conditions. While much research, materials testing, and improvement has occurred relative to cement formulations, some of the governing DRB State regulations have not been upgraded in over 20 years.

For example, PA regulations (State of PA, 1989 §78.85) do not specify the use of state-of-the-art self-sealing, special additive enhanced cements, or cements with enhanced mechanical and tensile strength or low shrinkage properties. **This is important to consider because gas migration represents 25 percent of the primary cement job failures (Gonzalo et al. 2005).**

Many new cements have been developed for assorted downhole conditions inclusive of high temperatures, high pressures, contaminants, mechanical deformation, etc. (e.g., CSI Technologies 2007; Salinas et al. 2005; Roth et al. 2008). As a result, new materials that are likely to improve and prolong zonal isolation may not be known by regulators and are not included in required practices.

CONCLUSION: Because short-term (i.e., less than 100 years) plug failure will almost assuredly occur, the draft DRBC regulations should be amended to include use of state-of-the-art sealant materials and permanent closure methods that fully seal all geologic horizons from the bottom of the wellbore to the ground surface. Even with this zonal isolation in place, today's technology has not advanced sufficiently to provide aquifer protection on the needed geologic – life of aquifer – time scale.

RECOMMENDATION: The DRBC draft regulations do not address cement plugging but leave this aspect of regulation to the host states. Prior to promulgating gas regulations, existing state regulations that were adopted over two decades ago by the host states need to be updated and enhanced by DRBC regulations that address well plugging technology and practices. The use of modern, high quality cement (or alternate high quality sealant) and plugging practices should be required by the DRBC. **Gas drilling approval is premature until technical advances can assure cement/well plugging competency because significant aquifer degradation is virtually assured using even the best cement/well plugging material available today.**

As discussed previously and above, downhole cement failure and casing corrosion are likely to occur naturally in less than 100 years. This risk is compounded in the Delaware River Basin because it is a seismically active region. The probability of an earthquake of magnitude 6 or more is high but even a magnitude 2 or 4 earthquake could lead to gas well failures due to shearing of well casings.

Shear of multiple well casings is a real possibility, followed by commingling of LNAPL, methane, and other contaminants. Dusseault et al. (2001), for example, document five or six small, shallow California earthquakes of relatively low magnitude (M2 to M4) as the cause of hundreds of sheared oilwell casings. In this case, the maximum horizontal shearing movement measured was approximately 225 mm (8.86 in).

CONCLUSION: Ground movement of this magnitude in the DRB could lead to significant and permanent groundwater contamination by thousands of failed wells, especially when the tight density of planned well installations is considered. Even the most durable concrete is not likely to withstand repeated and/or significant seismic activity. Dusseault et al. (2001) accent this:

> *"Earthquakes, landslides, and fault movements are expressions of induced shear stresses large enough to overcome natural material strength. ... Simulation results and field experience show that the strength of the casing-cement system is of little consequence in resisting shear displacement of strata. ... In general, however, the size of the induced shear planes is so large (greater than thousands of square meters) that the presence of a "strong" casing cannot resist slip, only retard the process somewhat."*

RECOMMENDATION: Conduct a long-term (i.e., > 10,000 years) seismic risk analysis for the Delaware River Basin. Drilling regulations and gas well permitting should not be advanced prior to assessing seismic risk that may compromise zonal isolation of freshwater aquifers.

Location and Bedrock Geology

All aspects of the DRBC regulations should be detailed in the regulations and should be consistent between states, always defaulting to the best state-of-the-art well field practices. This should include plugging and abandonment procedures, methods of determining optimal zonal isolation on an individual well basis, and guidelines that require well plugging throughout the entire vertical wellbore. The Marcellus and Utica shales extend under a large, multi-state, land area. The environmental risks associated with the installation of vertical exploratory wells and horizontal hydraulically fractured wells are interstate in nature and must be fully evaluated in this manner - not solely state by state or watershed by watershed. The need to comprehensively evaluate and regulate hydrologic and hydrogeologic risks on a gas field basis is paramount in order to provide required protection of the water resources of the Delaware River Basin.

Joints as Active Contaminant Pathways

The draft regulations fail to require comprehensive soil gas and seismic surveys in advance of well permitting to identify and avoid joint and fault pathways (i.e., potential contaminant pathways) that may naturally be open between gas shales and freshwater aquifers. Numerous joints are present throughout the Appalachian basin (Jacobi 2002; Evans 1994; Engelder et al. 2009; Lash and Engelder 2009). They have not been rigorously documented throughout the DRB (Rubin 2010).

In establishing a relationship between seismicity and faults, Jacobi (2002) examined Fracture Intensification Domains (FIDs), E97 lineaments, topographic lineaments, gradients in gravity and magnetic data, seismic reflections profiles, and well logs. Jacobi states:

> *"In interbedded shales and thin sandstones in NYS, fractures within the FID that parallel the FID characteristically have a fracture frequency greater than 2/m, and commonly the frequency is an order of magnitude greater than in the region surrounding the FID."*

Jacobi makes a case for repeated reactivation along faults in the Appalachian Basin. Furthermore, and importantly, Jacobi addresses his and Fountain's identification of FIDs based on soil gas anomalies over open fractures:

> *"Certain sets of FIDs are marked by soil gas anomalies commonly less than 50 m wide (Jacobi and Fountain, 1993, 1996; Fountain and Jacobi, 2000). In NYS, the background methane gas content in soil is on the order of 4 ppm, but over open fractures in NYS, the soil gas content increases to 40-1000+ ppm."*

The fact that Jacobi and Fountain have successfully identified and measured methane seepage from fractures that most likely extend downward to gas producing shales shows that open vertical pathways already exist, confirming the risk of increasing gas excursions as a result of exploratory boreholes penetrating joints and as horizontal wells are hydraulically fractured. Clearly, Jacobi and Fountain's work suggests that opening and expanding fractures that now naturally release methane from gas-rich shales will provide even greater gas and contaminant migration pathways if later interconnected and widened via hydraulic fracturing. Installation of vertical exploratory boreholes and hydrofracked horizontal gas wells into gas-rich joint sets should not occur until after full environmental review.

In the absence of hydraulic fracturing, vertical exploratory wells have been known to intersect high permeability gas-bearing fractures, sometimes with disastrous results. Engelder et al. (2009) document the presence of unhealed (i.e., methane-filled) joints at depth in the Marcellus shale and major blowouts that occurred when these unhealed joints were encountered (as cited from Bradley and Pepper 1938 and Taylor 2009). For example, Taylor (2009) discusses the 1940 Crandell Farm blowout near Independence, New York where massive uncontrolled gas flow occurred from joints intersected by an unstimulated vertical Marcellus well that lacked any evidence of faulting. Engelder et al. (2009) further discuss blowouts in the Marcellus Shale after the Crandell Farm blowout:

> *"Over the following half century, blowouts were a common consequence of drilling vertical wells penetrating the Marcellus. The low permeability of the Marcellus suggests that many, if not all, blowouts must have tapped a reservoir of interconnected natural fractures. In fact, blowouts were one of the major attractions drawing Range resources to Washington County, Pennsylvania, where Range started targeting the Marcellus gas shale during 2004 (W.A. Zagorski, personal communication)."*

Engelder et al. (2009) document that, even in the absence of stimulation (such as by hydraulic fracturing), some gas wells that tap unhealed and well-interconnected joint sets at depth are excellent producers. Clearly, preserved unhealed joints are important to gas production because healed fractures and veins would otherwise serve as barriers to gas flow (Engelder et al. 2009). Thus, vertical exploration wells that intersect permeable, gas-rich, interconnected joint sets pose a potential hydraulic pathway (i.e., with a decreasing pressure gradient) for upward migration and release of methane, especially in the event of casing or grout failure or stemming from seismic activity – whether natural or induced at some point later in time by hydraulic fracturing. In the latter case, earthquake or micro-seismicity stemming from future hydraulic fracturing in the area may result in shearing of exploration well casing and the opening of inter-formational pathways. Beyond this, blowouts themselves may pose a means of catastrophically interconnecting brine-rich and freshwater geologic horizons. Therefore, both vertical and horizontal components of gas wells pose the potential risk of adverse environmental impacts. DRBC therefore should not provide a lesser degree of oversight and regulation of exploratory or vertical wells as proposed in the draft regulations at Sections 7.3(e)(4), TABLE 7.3.1, 7.5(e)(7), 7.5(h)(1)(i).

Thus, numerous joints in the Appalachian Basin, even in the absence of gas well installations, provide open, functioning, avenues for upward migration of methane. Gas-rich joints encountered by exploration or vertical well boreholes may interconnect and enhance preexisting joint pathways for methane, deep-seated saline water, radioactivity and, following development of horizontal gas wells, for contaminated LNAPL fracture fluids to migrate to aquifers, reservoirs, lakes, rivers, streams, wells, and even homes.

Contamination of Freshwater Aquifers and Loss of Aquifer Integrity

Contamination of freshwater aquifers via the mechanisms detailed above by Dusseault et al. (2000) (i.e., methane entering formations from leaking circumferential fractures) is likely to be far greater than more limited contamination proximal to well heads. Freshwater aquifers in Wayne County, PA, for example, extend to at least 665 feet, as observed at the Matoushek #1 well (Stiles 2010). Permitting the installation of vertical exploration wells needs to be considered in the broader environmental setting where these wells may ultimately be completed as hydrofracked horizontal production wells. Should natural ground motion from earthquakes (and possibly from seismically induced earthquakes from future hydrofracked wells) occur, it is likely that alternate groundwater flow paths will develop. These flow paths will then provide avenues for migration of gas well related contaminants, particularly low density or gaseous ones. Pre-existing joint sets that are already open to gas-rich shales (Jacobi 2002) will provide pathways and release avenues for methane and any LNAPLs that may be present. In this way, vertical fractures extending into overlying bedrock formations may result in the disruption and alteration of natural groundwater flow. Again, DRBC therefore should not provide a lesser degree of oversight and regulation of exploratory or vertical wells as proposed in the draft regulations at Sections 7.3(e)(4), TABLE 7.3.1, 7.5(e)(7), 7.5(h)(1)(i).

Understanding the cumulative impacts of natural gas drilling in the Delaware River Basin is essential in order to determine how this activity should be regulated. By way of analogy, using a somewhat different but worst case example, solution mining in Tully Valley, New York, demonstrates how alteration of a previously isolated and intact freshwater aquifer was compromised via anthropogenic activities (Rubin et al. 1992; Figure 17). While not physically observable on the ground surface, the adverse environmental impacts of gas production throughout large portions of the Appalachian Basin, may have much broader and far reaching impacts. The Tully Valley example described below demonstrates the nature and consequences of disrupting a previously intact groundwater flow regime. This analogy is especially applicable to adverse environmental impacts likely to occur with hydrofracked wells.

As illustrated in the Tully Valley example, once even a few significant fracture interconnections (i.e., planer, laterally extensive, and potentially interconnected with Fracture Intensification Domains) are established between target shale beds and the ground surface, naturally isolated groundwater flow systems then become accessible for commingling of formation waters, for transmission of contaminants, for the unnatural and increased recharge of deeper formations, and for the establishment of new groundwater flow routes. Much as methane can be released upward to lower pressure formations from exploration wells, so will Light Non-Aqueous Phase Liquids (LNAPLs) rise upwards along fault and fracture pathways if horizontal gas wells follow exploration well installations, thereby broadly contaminating freshwater aquifers. Then, as new groundwater circulation pathways develop in response to repeated hydro-fracturing and newly available freshwater hydraulic/pressure heads, more and more commingling of freshwater and contaminant-laden, saline, water is likely.

With time, methane (and hydro-fracturing chemicals as gas production is permitted) will move with groundwater flow, down valley, toward zones of lower hydraulic head, particularly valley bottoms, major streams, and principal aquifers. Areas with higher groundwater flow velocities are likely to develop groundwater circulation patterns along Fracture Intensification Domains (i.e., high permeability pathways), especially where hydro-fracturing has opened elongate fracture pathways that have high hydraulic gradients between watershed uplands and valleys. To a large degree, these new circulation pathways will resemble those illustrated in the Figure 17 Tully Valley example – albeit fracture aperture width may be narrower and associated catastrophic collapse less likely.

It is not prudent to ignore the overall physical setting within which both horizontally fractured gas production wells, exploration or vertical well installations may ultimately fit. Since it has been shown above that many of the environmental risks normally attributed only to horizontal gas wells directly relate to unfracked vertical exploration wells (e.g., seismic risk, grout shrinkage, vertical flow pathways into freshwater formations), it is prudent to at least cursorily review broader gas production based environmental considerations and not to allow a lesser degree of oversight and regulation of exploratory and vertical wells.

Hydraulic Fracturing and Repeated Hydraulic Fracturing Impacts

While gas field fracture aperture may be narrower than the disrupted Tully Valley example, it is important to recognize that the hydraulic transmissivity of fractures increases by the cube of the effective fracture width, thereby pointing out the likely increased risk associated with repeated hydro-fracturing. The combination of excessive pressure associated with hydro-fracturing and lubricated fault planes may lead to increased faulting and seismicity, followed by increased groundwater circulation between formerly isolated hydrologic horizons. Northrup (2010), for example, references a hydro-fracturing induced earthquake in Cleburne, Texas – the likely tip of the iceberg. Once these new groundwater circulation pathways are established, it will be impossible to restore the integrity of adversely impacted freshwater groundwater flow systems, contaminant migration and dispersal will expand, and plugging and abandonment procedures of gas production wells will have little impact on retarding water quality degradation throughout irreparably compromised aquifer systems.

Cumulative impact studies must address potential adverse environmental impacts associated with gas production wells and the overall long-term plan for the installation of hundreds or thousands of horizontal hydraulically fractured wells throughout the Delaware River Basin. This analysis must address how repeated fracturing cycles seriously exacerbate risks of contaminant migration. The goal of hydraulic fracturing is to interconnect joints, faults, bedding planes, and other partings (i.e., fractures collectively) through horizontal boreholes, thereby increasing gas extraction productivity. Naturally occurring excursion of methane gas via faults and fractures has long been recognized. Hydraulic fracturing will create new fractures as well as open and enlarge existing, natural fracture aperture widths causing aquifer and ground water contamination risk. Recent studies are now beginning to confirm that both methane and hydro-fracking chemicals are migrating upward along hydro-fractured fracture pathways to freshwater aquifers and homeowner water supplies. For example, Lustgerten (2009) references scientific work conducted on methane gas excursions in Garfield County, Colorado where a three-year study used sophisticated scientific techniques to match methane from water to a deep gas-rich bedrock layer stating:

> *"The Garfield County report is significant because it is among the first to broadly analyze the ability of methane and other contaminants to migrate underground in drilling areas, and to find that such contamination was in fact occurring. It examined more than 700 methane samples from 292 locations and found that methane, as well as wastewater from the drilling, was making its way into drinking water not as a result of a single accident but on a broader basis. As the number of gas wells in the area increased from 200 to 1,300 in this decade, methane levels in nearby water wells increased too. The study found that natural faults and fractures exist in underground formations in Colorado, and that it may be possible for contaminants to travel through them. Conditions that could be responsible include vertical upward flow along natural open-fracture pathways or pathways such as well-bores or hydraulically-opened fractures …"*

What we are just beginning to understand is the fact that repeated fracturing at each well will further amplify all of these risks. Reaping maximum gas production from horizontal gas wells commonly requires repeated hydro-fracturing of wells (see discussion by Northrop 2010). With each successive hydro-fracturing event, more toxic contaminants are introduced into subsurface formations, including those already aggravated and potentially opened in the first fracturing cycle. In addition, as gas companies expand their operations, they may turn to the new, more effective, multilateral drilling technology to selectively tap multiple target zones in adjacent areas. This will necessarily result in multiple wellheads and multiple fracturing operations in close proximity. Through these processes, it is highly likely that new, previously unconnected, fractures will be integrated into the area influenced by each production well.

David Kargho et al. (2010), U.S. EPA Region III, recently cautioned about the particular challenges still unresolved about drilling in tight shale formations:

> *"The control of well bore trajectory and placement of casing become increasingly difficult with depth…At the Marcellus Shale, temperatures of 35-51°C (120-150°F) can be encountered at depth and formation fluid pressures can reach 410 bar (6000 psi) (8). This can accelerate the impact of saturated brines and acid gases on drilling at greater depths. In addition, the effect of higher temperature on cement setting behavior, poor mud displacement and lost circulation with depth makes cementing the deep exploration and production wells in the Marcellus Shale quite challenging. For example following a recent report by residents of Dimock, PA, of natural gas in their water supplies, inspectors from the Pennsylvania Department of Environment Protection (PADEP) discovered that the casings on some gas wells drilled by Cabot Oil & Gas were improperly cemented, potentially allowing contamination to occur….During drilling into*

the tight Marcellus Shale, there is a slight risk of hitting permeable gas reservoirs at all levels. This may cause shallow gas blowouts and underground blowouts between subsurface intervals. Other geo-hazards that may pose challenges to drillers in the Marcellus Shale include: (1) disruption and alteration of subsurface hydrological conditions including the disturbance and destruction of aquifers, (2) severe ground subsidence because of extraction, drilling, and unexpected subterranean conditions, and (3) triggering of small scale earthquakes."

With each repeated fracturing cycle, all of the "challenges" noted by Kargho, Wilhelm, and Campbell of necessity multiply and increase. See also the BP internal report reported September 9, 2010, attributing fault for the 2010 Deepwater Horizon oil rig explosion to unexpected cementing problems at pressures less than those of the average shale gas frack. Studies have not yet been done regarding the effect of depth and pressure on casing failure rates in tight shale formations or on the repeated fracturing re-pressurization under such temperature and depth conditions on cement casings and joints. Nor have studies or plans been developed for remedial action should the casings and joints fail at extreme depth.

Repeated hydraulic fracturing may activate pre-existing faults or induce shifting or settlement along lubricated fractures. Parts of Pennsylvania and New York State within and near the Delaware River Basin are seismically active. Excessive lubrication of faults and fractures with highly pressurized hydraulic fracturing fluids, bolstered by repeated hydrofracturing episodes, may result in fault activation and bedrock settlement. This, in turn, may result in catastrophic shearing of production well boreholes and casing strings even in the absence of natural seismic activity. Pre-existing old and poorly abandoned oil and gas wells may also provide additional contaminant migration pathways. Unlike the British Petroleum well that was finally plugged, once the structure of the bedrock has been compromised by faulting and/or hydraulic expansion of joints, and formation waters have commingled, aquifer restoration will not be possible.

The risk of ground collapse as a result of repeated fracturing cycles should also be studied prior to issuing regulations. "*Severe ground subsidence*" may occur "*because of extraction, drilling, and unexpected subterranean conditions*", as may "*disruption and alteration of subsurface hydrological conditions including the disturbance and destruction of aquifers*" (Kargbo et al., 2010).

Hydraulic Fracturing and Well Spacing Considerations

Risks of casing failure are further compounded by the frequency (or spacing) of casing couplings which may be on the order of every 100 feet or less. Zhou et al. (2010) assessed casing pipes in oil well construction and the risk that they may suddenly buckle inward as their inside and outside hydrostatic pressure difference increases. They point out the importance of measuring the stress state of casing pipe, complete with real-time monitoring and state-of-the-art warning system installations. **Consideration should be given to evaluating cost-effective and reliable sensing technologies and installation techniques for long-term monitoring and evaluation of**

casing pipe before issuing gas well related regulations. Most deeply buried casings are difficult to repair or replace and, as such, can lead to aquifer contamination. Even a small percent casing or grout failure can be effectively irremediable at deep depths and irreparably harm ground and surface water sources.

Hydraulic Fracturing and Homeowner Well Considerations

Homeowner wells do not need to be near gas production wells to be adversely affected by the upward migration of methane gas and Light Non-Aqueous Phase Liquid (LNAPL) contaminants from gas-rich shales. Neither discussion of known fracture frequency nor existing maps depicting massive fracturing throughout the Delaware River Basin appear to have been incorporated into the well permitting review process. As such, many of the real risks attendant on vertical exploratory well installations, or future horizontal hydraulic fracturing of gas-rich shale beds, have not been addressed. <u>Mapping of existing fractures should be done by DRBC before promulgating regulations in order to assess the probability of risk of contamination.</u>

As some vertical fractures are widened and opened via hydrofracturing, they will and most probably have already, in some cases, provided a hydraulic avenue where methane is released upward into and throughout these well-integrated Fracture Intensification Domains. Thus, fractures enlarged by hydrofracturing will provide lower pressure gas release points or routes. Once vertical and lateral fracture pathways are open, even a limited number, natural gas and LNAPLs will migrate extensively throughout formerly isolated upper bedrock and freshwater aquifer groundwater flow systems. As methane is released upward along vertical borehole pathways, and along future hydrofractured boreholes and their interconnected fractures, homeowner wells will provide a final open fracture and cased pathway to the ground surface from methane contaminated aquifers.

Because horizontal components of gas wells extend may thousands of feet and may intersect numerous planar vertical pathways, large-scale aquifer degradation is possible. Initially, aquifer degradation can be expected above and adjacent to boreholes with poor grout seals. With time and successive hydrofracturing episodes conducted in individual wells, methane and LNAPLs that are released upward through fault planes and related fractures will widely contaminate freshwater aquifers and surface water receptors.

Some of the contaminated groundwater in areas now undergoing hydraulic fracturing is far removed from gas production wellheads, thus strongly indicating that groundwater contamination is already occurring along vertical fault and fracture pathways, distant from potential poor wellhead grout jobs or casing failures. This topic is discussed here because understanding the cumulative impacts of natural gas drilling in the Delaware River Watershed is essential in order to determine how this activity should be regulated. Fractures extend from gas-rich shales to the ground surface and naturally leak methane gas. Repeated hydraulic fracturing is likely to exacerbate this situation. Repeated hydraulic fracturing within numerous individual wells will serve to expand and extend these existing fractures through freshwater aquifers. This will increase upward migration of methane to aquifers, streams, homes, and wellheads. Dimock, Pennsylvania provides an excellent case in point.

Hydraulic Fracturing and Pollution Pathways

It is likely that contaminant dispersal along fault and fracture pathways will be the more common mechanism whereby natural gas and LNAPL excursions find their way into aquifers, homeowner homes, well houses, and streams – not solely via pathways stemming from poor casing grouting. This mechanism also explains why many of the gas contamination incidents reported to date are far removed from individual gas production wellheads (e.g., up to 1,300 feet in the Dimock, PA area; COP 2009). This contaminant dispersal mechanism also strongly accents why gas companies would much prefer to admit that poor or failed casings or poor grout integrity is the root cause of gas excursion problems. Certainly, in the gas industry, it is far preferable to invoke any gas leak mechanism other than that of widespread, uncontrolled, and undocumented upward and lateral migration of formerly isolated methane gas into and through freshwater aquifers.

As in the Tully Valley example above, the loss of natural geologic and hydrologic integrity throughout formerly isolated geologic formations poses an enormous threat to the existing and future way of life in planned gas exploitation areas. However, the disruption of the geologic strata presented in the Tully Valley Figure 17, while having wider fracture apertures and relatively great vertical offset of geologic beds, has occurred in an area far smaller in areal extent than what is planned extensively throughout the Delaware River Basin and much of the Appalachian Basin. Gas excursions are likely to occur throughout the Appalachian Basin, wherever there are mapped and as yet undocumented fractures. Because of the physical nature of existing fractures systems, these excursions, even a few in an area, are likely to degrade freshwater aquifers such that existing and new homeowner well installations will be degraded.

Because permitting of vertical exploration wells may result in numerous adverse environmental impacts (discussed above), it is important to fully consider the broader gas field development picture and related environmental impacts. Radioactive radium present in the Marcellus may also be mobilized in hydrofracking fluids and thus become available for transport in the groundwater flow system. This appears to be particularly true of uranium that University of Buffalo researchers recently determined is released during the hydraulic fracturing process (presented at a GSA meeting on Nov. 2, 2010). Tracy Bank and her colleagues determined that hydrofracking forces toxic uranium into a soluble phase and mobilizes it, along with chemically bound hydrocarbons, thereby making it available for groundwater transport. In addition, uranium tainted flow back water poses the risk of contaminating streams, wetlands, and ecosystems.

Fracking contaminants, once mobilized vertically along fault planes and joints, especially under pressurized conditions, can reach freshwater aquifers. Even if all fracking fluids were composed of non-toxic chemicals, the risk of interconnecting deep saline-bearing formations (i.e., connate water) and/or radioactive fluids with freshwater aquifers is great. Any commingling of deep-seated waters, with or without hazardous fracking fluids is unacceptable. Documented gas excursions near existing gas fields demonstrate that vertical pathways are open. If gas can migrate to the surface, it is highly likely that hydrocarbon and contaminant-rich Light Non-Aqueous Phase Liquids (LNAPLs) will also reach aquifers and surface water resources. These contaminants may then also migrate to down gradient wells, principal aquifers, and waterways.

Artificially enlarged and expanded hydrofracked fractures may provide vertical pathways for light, low density, drilling fluid chemicals and radon. Some fracking related contaminants will migrate upwards via fractures into freshwater aquifers - particularly Light Non Aqueous Phase Liquids (i.e., LNAPLS - less dense hydrocarbons) inclusive of benzene, a known carcinogen. In addition, increased upward migration of radon is likely to occur. The pathways are already there and functioning, waiting to be further expanded and laced with toxic chemicals.

There is a growing catalog of hydro-fracking related accidents in other gas-field plays (see e.g., Hazen and Sawyer 2009). Accidental spills of fracking fluids and flow-back water has the potential of contaminating ground and surface water. Similarly, lateral and upward migration of hydro-fracturing chemicals pose a real risk to Delaware River Basin aquifers, especially to moderate and high yield unconfined aquifers situated in stream valleys that receive their base flow recharge from up-gradient groundwater aquifers.

Excursion of frack fluids from breached flow-back wastewater containment structures, whether via rupture, leakage, or overflow poses a real threat to surface water quality. Overland flow of flow back fluid chemicals to streams, ponds, wetlands, and waterways poses an immediate water quality and ecosystem concern that should be fully evaluated prior to issuance of draft regulations.

In the broader context of fully examining all potential adverse environmental impacts, it is necessary to not only look at impacts associated with vertical exploration wells, but also planned future horizontal hydrofracked wells. Excursion of frack fluids from breached flow-back wastewater containment structures, whether via rupture, leakage, or overflow, poses a real threat to groundwater quality. Slow infiltration of frack fluid chemicals to groundwater and its potential degradation need to be fully addressed prior to issuance of draft regulations.

Poor or failing exploratory and production well construction (e.g., poor grouting, corroded casing) may provide vertical pathways for contaminant excursions from deep shale beds upward into freshwater aquifers. While this has already been documented, increased gas well installations will also increase the number of failed wells and resultant contaminant migration. Apparently, at this time, gas field contaminant excursions are not being treated as outward expanding contaminant plumes that warrant expensive, full-scale, hydrogeologic characterization, groundwater clean-up, and remedial action. The importance of this must be underscored because aquifer restoration on a gas field scale, even if cost were not an issue, may not be possible.

Water Quality Monitoring and Emergency Response Planning

Chemical baseline and annual water quality monitoring should be a regulatory requirement established before well permits are issued. If exploratory well installations and hydrofracturing of gas wells in the Delaware River Basin are to be regulated and permitted, chemical monitoring of groundwater wells and likely surficial contaminant receptors (i.e., seeps, springs, wetlands, streams) should be conducted before well installations (i.e., base line conditions) and annually thereafter. Evidence of contravention of groundwater or surface water standards prior to one year should trigger earlier testing.

Based on findings of the Commonwealth of Pennsylvania (COP, 2009) and Rubin (this report), all homeowner wells located within 2,000 feet of well pad horizontal projection arrays should be incorporated into a comprehensive monitoring program (see Figure 6, bottom left hand corner). Evaluation of other adversely impacted homeowner wells may well result in a greater distance recommendation.

An Emergency Response Plan should be prepared and approved in advance of issuance of any well drilling permits. The particulars of this plan should be carefully considered prior to issuance of draft regulations and should include hydrologic means of capturing, recovering, treating, and monitoring frack fluids from throughout all horizontal and vertical boreholes, as well as from degraded freshwater aquifers. It is likely that hydrologic modeling conducted as part of the response plan evaluation will reveal that the best means of limiting further aquifer degradation may, as in the case of the Love Canal remedial plan, be to maintain an inward hydraulic gradient via pumping to a contaminant collection system. If this approach turns out to be the best means of protecting untainted portions of compromised freshwater aquifers by retarding outward contaminant movement, then the plan must provide for long-term contaminant collection, treatment, and monitoring - perhaps on the order of many tens or hundreds of years, as well as fluid treatment and disposal costs. This same assessment might do well to also evaluate if there are certain contaminant threshold levels above which well field closure is required. As in the recent British Petroleum oil spill, a high end (i.e., well funded) response and clean up fund should be in place prior to issuance of draft regulations and well drilling permits. In the event that hydrofracking related company tracers and/or other frack fluid contaminants are found in wells and/or surface waters, the Emergency Response Plan (i.e., damage mitigation plan) should be immediately initiated.

Endangered Species

Excursions of gas field related contaminants may lead to take of endangered, threatened and other imperiled or at-risk species. Potential commingling of deep connate waters, hydrofracking fluids, methane, and freshwater aquifers, as a result of disrupted bedrock strata, may lead to new, altered, groundwater flow regimes. Altered flow regimes may, in turn, result in the formation of new aquifer discharge locations that effuse methane and other contaminants to streams, springs, wetlands, or other locations. The potential exists for such contaminants to degrade surface water quality and sensitive ecosystems that support threatened or endangered species (Tzilkowski et al. 2010; NYSDEC and PFBC, 2010), such as the federally endangered Dwarf Wedge–mussel (*Alasmidonta heterodon*). Of the few remaining populations of this species, one is found within the Neversink River, one in the mainstem of the upper Delaware River, and another within a small coldwater tributary of the middle river (Playfoot and Snyder 2010). Dwarf wedge-mussels are protected under the federal Endangered Species Act. It is critically important that pristine water quality conditions be maintained to protect this species.

There are real environmental, water quality, air quality, explosive, health, and endangered species concerns regarding gas exploitation below carbonate beds, inclusive of in caves. Carbonate formations in portions of the Delaware River Basin are recognized among karst hydrologists as being karstic or cave/conduit bearing in nature. Hydrofracking-related contaminants that may enter karstic solution conduits, from below or above, would quickly degrade groundwater and surface water quality.

Carbonates of the Onondaga Formation and Helderberg group outcrop in portions of the Delaware River Basin (Figure 18; Veni 2002). These carbonate formations, while stratigraphically lower than the Marcellus shale, overlie other shale beds that are gas rich (e.g., the Utica shale of the Trenton Group). An important aspect of karst is its effect on water supply and contaminant transport. Water in solution conduits can travel up to several kilometers per day, and contaminants can move at the same rate. This poses serious problems when monitoring for water quality. Contaminants enter the ground easily through sinkholes and sinking streams, and filtering is virtually non-existent. Even small solution conduits can transmit groundwater and contaminants hundreds of times faster than the typical unenlarged fracture network. Methane or drilling-related contaminants that may enter karstic solution conduits, from below or above, would quickly degrade groundwater and surface water quality. Because karst aquifers are extremely vulnerable, it would be prudent to characterize the environmental risks to them prior to issuing draft regulations.

Gas drilling activities may pose a health risk to cave-dwelling species and cavers, including the federally endangered Indiana bat (*Myotis sodalis*). The build up of methane and other toxic chemicals in caves and mines may pose both an explosive and health risk to cavers, cave scientists, and cave-dwelling fauna. People and bats in caves may potentially be overwhelmed by the build up of methane and other toxic chemicals. This could lead to their deaths via inhalation or via explosions similar to those that have occurred at wellheads above gas plays. If methane, LNAPLs, or fracking fluids were to seep or flow into caves (from below or from leaking surface holding pits) situated above gas-rich shales, caves might in effect become "confined spaces" - toxic to breathe in with great and, possibly, rapid exposure risk. Importantly, cave dwelling animals, such as bats (Figures 19 and 20), might have their already stressed populations (i.e., via White-Nose Syndrome; USGS, 2010) further decimated by gas field related contaminant excursions.

The endangered Indiana bat has one or more hibernacula in the Delaware River Basin stratigraphically above the Utica Shale. To protect these bats, the NYS Department of Environmental Conservation (i.e., State of New York) purchased Surprise Cave, located near Mamakating, NY (Sullivan County) some years ago. There may be other bat hibernacula within the Delaware River Basin.

Conclusions

Gas wells and related surface activities have the potential to permanently and irreparably harm ground and surface water resources in the Delaware River Basin. Importantly, methane released under pressure from failed cement sheaths and casings follows fractures to homeowner wells and water bodies (see Figure 21). Extensive existing fracture and fault networks throughout the Appalachian Basin may provide upward pathways for contaminant and gas migration through geologic zones believed to be physically isolated, based on incomplete data. Although gas producers have asserted publicly that these zones are physically isolated, to date there are no publicly available studies to prove this claim. On the contrary, multiple studies indicate the presence of pervasive natural fracturing that will allow for migration to freshwater aquifers of methane, other hydrocarbons and their constituents, drilling fluids and materials, and naturally occurring hazardous materials including deep saline waters and NORMs. As a result, there are significant health and environmental risks associated with gas well development in the Delaware River Basin and elsewhere in the Appalachian Basin.

The characterization of vertical fractures, faults, seismic hazards, casing and grout failures, contaminant hazards, and methane soil gas in the Delaware River Basin and elsewhere in the Appalachian Basin is not adequate to address potential adverse environmental impacts. Existing information does not sufficiently address pre-existing contaminant (i.e., gas and fluid) pathways that extend from the Marcellus shale to aquifers, surface water bodies, and the ground surface. Both vertical exploratory wells and hydrofractured wells and associated fractures may significantly increase gas excursions to formerly isolated geologic formations. Review of reports and news articles indicate that significant environmental contamination has occurred in geologically similar settings, including explosive hazards and groundwater and surface water contamination. This indicates that the Delaware River, its tributaries, and watershed are at substantial risk of pollution and degradation.

Documentation by Jacobi of Fracture Intensification Domains based on methane soil gas anomalies over open fractures reveals evidence that naturally occurring fractures and faults provide upward gaseous migration pathways, even in the absence of deep hydro-fracturing in the Marcellus shale. If fracture and fault networks are intersected by vertical, exploratory, or horizontal well completions and/or integrated and enlarged via hydro-fracturing processes, it is likely that methane, LNAPL, and radioactive gas excursions will increase, even if cementing and casing operations of wellbores do not fail.

The installation of gas wells that open borehole or nearby joint pathways between formerly separated geologic horizons pose an environmental risk, particularly because the area is seismically active. Ground motion associated with seismic activity has the real potential of instantly shearing multiple well casings throughout gas fields, degrading cement grout designed to isolate geologic horizons (i.e., freshwater aquifers), and thereby opening vertical joint and borehole vectors between formerly separated geologic horizons. Numerous earthquakes have occurred in Pennsylvania, New York, and adjacent states, pointing out that the region of planned gas wells is seismically active.

Methane gas extraction from tight shale formations, including the Marcellus and similar formations throughout the country, has contaminated ground and surface waters. Reasons for this include poor containment of fracturing fluids, spills of flow-back water, intentional illegal disposal, mixing of different formation waters (e.g., brine and fresh water), inadequately grouted casing, failed grout, spills, uncontrolled movement of gas and contaminated fluids through existing or anthropomorphically created fractures, and various forms of operator error. Increased gas production in the Delaware River Basin and elsewhere in the Appalachian Basin would almost certainly result in contaminant excursions, even under the best planned conditions.

As discussed above, it already has. The presence of confirmed fractures and faults that extend from gas-rich geologic beds to the ground surface, some of which extend laterally for miles and are closely linked with others formed under similar structural conditions, pose potential contaminant pathways to surface waterways, reservoirs, and freshwater aquifers.

Because the density, location, aperture width, and length of all fractures (often present and not visible beneath a soil mantle) are not known, it would not be prudent to risk placement of numerous gas wells within sub-basins that contain lakes and reservoirs used for public water supplies. From a water quality standpoint four facts stand out:

> 1) there is a point at which the actual total number of toxic contaminants introduced into a groundwater flow system no longer matters because the water is unlikely to ever be potable again no matter how much money is spent attempting to remediate it,
>
> 2) new groundwater circulation pathways are likely to develop in response to repeated hydro-fracturing and newly available freshwater hydraulic/pressure heads, resulting in commingling of freshwater and contaminant-laden waters,
>
> 3) eventually, even deep groundwater flow systems discharge to surface water, albeit it may take many years to occur (i.e., analogous to a slowly ticking time bomb), and
>
> 4) it makes little sense to jeopardize the quality of surface and groundwater by intentionally introducing vast quantities of toxic contaminants into the environment, especially where gas-conducting fractures and faults are known to extend from gas-bearing formations to the ground surface.

Natural gas development projects will not promote the use and development of the Basin's water resources in a sustainable manner that avoids pollution of or injury to the water resources of the Basin (as contemplated in Section 7.1(e)).

Protection of the high water quality of the basin is not likely to be achieved because the materials and technology (i.e., effective zonal isolation materials) required for "long-term isolation" of freshwater aquifers via existing well completion and cementing methods are not sufficiently developed to withstand stresses of the downhole environment. Drilling regulations must insure that surface water and freshwater aquifers will be protected for hundreds of thousands of years, or more.

Areas of the regulations that default to state-specific requirements should instead be made to conform to those most stringent. The text of these regulations should then be incorporated into the regulations so there is consistency throughout the watershed.

Gas company specific tracers should be incorporated into all drilling and hydrofracking fluids.

All orphan and poorly sealed wells, if formerly owned or leased by companies seeking drilling permits in the DRB, should be corrected by them prior to receiving permits for new gas well installations. If orphaned, inadequately sealed wells are not remediated, new drilling should not be allowed within an area that could disturb or impact the orphaned well. A geologic survey of existing subsurface conditions and adjacent aquifer mapping should be used to set the area of no further disturbance.

A comprehensive analysis should be conducted of long-term cement/concrete life prior to promulgating regulations that may permit use of downhole cementing materials and procedures that are not protective of the life of aquifers. Alternately, the findings provided in this report may be adopted and considered when amending the draft regulations.

Drilling regulations should not be finalized before completion of an in-depth evaluation of seismic risks to casing and downhole cement sheath integrity (i.e., seismic risk assessment).

While the draft regulations address some of the day-to-day well permitting and regulatory activities, they should not be finalized until after comprehensive risk analyses have been completed that address the long-term water quality risks from failed annular sheaths, casings, and plugs and seismic activity.

The opinions expressed herein are stated to a reasonable degree of scientific and professional certainty.

Figure Listing: (Available at http://hydroquest.com/DRBCfigures/)

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