



April 15, 2011

Commission Secretary
Delaware River Basin Commission
P.O. Box 7360
25 State Police Drive
West Trenton, NJ 08628-0360

Re: Natural Gas Development Regulations – DRAFT

Dear Commission Secretary and Commissioners,

Delaware Riverkeeper Network (“DRN”) and the Natural Resources Defense Council (“NRDC”) submit these comments regarding the Commission’s Draft Natural Gas Development Regulations (“the Draft Rules”), proposing a new Article 7 of Part III - Basin Regulations, issued for public comment December 9, 2010.

DRN, a nonprofit membership organization dedicated to the Delaware River Watershed, has over 8,000 members throughout the Watershed and works to protect, defend, and restore the Delaware River, its tributaries and habitats. NRDC is a national, nonprofit legal and scientific organization that is active on a wide range of environmental issues, including the risks associated with inadequately regulated gas development. NRDC has more than 90,000 members in the member states of Pennsylvania, New York, New Jersey and Delaware.

These comments include and reflect the findings of technical experts engaged by DRN and NRDC to analyze and report on the Draft Rules. All reports are submitted with these comments and are appended to this document.

These comments conclude that the Draft Rules do not provide the necessary means for the Commission to fulfill its legal mandate to protect the water resources of the Delaware River Basin during the construction, operation, and decommissioning of natural gas development projects. The Draft Rules rely in too many instances on the state oil and gas regulatory programs in Pennsylvania and New York (the

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“host states”), which are inadequate to accomplish the Commission’s goals, legal obligations, and regulatory responsibilities. In instances where the Draft Rules exceed host state program requirements, the proposed standards do not provide sufficient controls to achieve “no measureable change except toward natural conditions” or to protect the water resources of the Delaware River Basin as required by the Compact, the Water Code, and the Administrative Manual: Rules of Practice and Procedure.

We respectfully request that the Commission withdraw the Draft Rules, complete comprehensive environmental and cumulative impact analyses, learn from other scientific studies that are in process such as the U.S. Environmental Protection Agency’s (EPA’s) hydraulic fracturing study that is about to commence and the New York State Department of Environmental Conservation’s Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and accomplish necessary planning initiatives and key research efforts before redrafting proposed natural gas development regulations.

The Delaware River’s waters are protected under the terms of the Delaware River Compact and the Delaware River Basin Commission’s Special Protection Waters Program. As such, the DRBC is legally obligated to enact regulations that ensure that no harm is done to the Special Protection Waters of the Delaware River. The Draft Regulations, if promulgated in their current form, will fail to meet this obligation.

DRN, NRDC, and SC engaged eight experts to review and assess the Draft Rules, develop conclusions and make recommendations. These comments incorporate and rely upon the comments, recommendations and conclusions of these expert reports. The curriculum vitae for these experts are collectively submitted as **Attachment 1**. The expert reports themselves are submitted as **Attachment 2**. We also relied upon the conclusions of the expert reports commissioned by DRN and Damascus Citizens for Sustainability as well as by the DRBC itself in preparation for the consolidated administrative hearing on the exploratory wells, 2010. The curriculum vitae for these experts are collectively submitted as **Attachment 3**. The expert reports themselves are submitted as **Attachment 4**.

Legal Framework

Delaware River Basin Compact

Under the Delaware River Basin Compact of 1961, the DRBC is charged with conserving and managing the water resources of the Delaware River and its watershed.

Article 13, Section 13.1 of the Compact provides for the development and adoption, and periodic review and revision, of a Comprehensive Plan “for the immediate and long range development and use of the

water resources of the basin. The plan shall include all public and private projects and facilities which are required, in the judgment of the commission, for the optimum planning, development, conservation, utilization, management and control of the water resources of the basin to meet present and future needs.”

The DRBC implements the Compact’s directives and objectives and the Comprehensive Plan through the Water Code and the Administrative Manual: Rules of Practice and Procedure (“RPP”) (codified at 18 CFR §§ 401.81–90).

Article 3, Section 3.8 of the Delaware River Basin Compact requires that

No project having a substantial effect on the water resources of the basin shall hereafter be undertaken by any person, corporation, or governmental authority unless it shall have been first submitted to and approved by the commission, subject to the provisions of Sections 3.3 and 3.5. The Commission shall approve a project whenever it finds and determines that such project would not substantially impair or conflict with the Comprehensive Plan and may modify and approve as modified, or may disapprove any such project whenever it finds and determines that the project would substantially impair or conflict with such Plan. The Commission shall provide by regulation for the procedure of submission, review and consideration of projects, and for its determinations pursuant to this section. Any determination of the Commission hereunder shall be subject to judicial review in any court of competent jurisdiction.

See also 18 C.F.R. § 401.32.

The DRBC’s Special Protection Waters Program

The Delaware Riverkeeper Network petitioned the Delaware River Basin Commission (DRBC) in 1990 to develop a program to protect the exceptional water quality and outstanding resources of the designated Wild and Scenic Delaware River pursuant to the Outstanding Natural Resource Waters (ONRW) provision of the federal Clean Water Act.

In response, the DRBC amended its Water Code to include its unique version of ONRW, the Special Protection Waters program. In 1992 the DRBC granted the Upper and Middle Delaware Wild and Scenic River segments Outstanding Basin Waters status under their Special Protection Waters (SPW) program.

In 2001, after the Lower Delaware River was designated by Congress as Wild and Scenic, DRN again petitioned DRBC to classify the Lower Delaware River as SPW. As a result of DRN’s efforts, the DRBC permanently designated the Lower Delaware River as Significant Resource Waters, a type of SPW, in July 2008.

The entire non-tidal Delaware River is protected by Special Protection Waters anti-degradation regulations. This designation requires strict regulation to protect the water quality of all SPW waters, which is documented as “exceptional” through regular water quality testing by the DRBC. The agency must maintain the high existing water quality so that there is **“no measurable change”** except towards natural conditions. Water Code § 3.10.3 et seq. codifies the anti-degradation program of the DRBC’s Special Protection Waters program. (DRBC Resolution Nos. 70-3, 92-21, 94-2, 2008-9); See also 18 C.F.R. Part 410; Water Code §2.200.1(Resolution No. 67-7)(“[t]he quality of Basin waters shall be maintained in a safe and satisfactory condition for...wildlife, fish and other aquatic life”); Water Code §2.20.2 (“[t]he underground water-bearing formations of the Basin, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected”); Water Code §2.20.5 (“[n]o underground waters, or surface waters which are or may be the sources of replenishment thereof, shall be polluted in violation of water quality standards duly promulgated by the Commission or any of the signatory parties”); Water Code §3.40.4.B (“[i]t is the policy of the Commission to prevent degradation of ground water quality....No quality change will be considered which, in the judgment of the Commission, may be injurious to any designated present or future ground or surface water use”). The Draft Regulations fail to ensure that there will be no measurable adverse change to the quality of the Basin’s water resources.

DRBC Jurisdiction over and Review of Projects that Will Have a Substantial Effect on the Water Resources of the Basin

There are a variety of ways in which projects can be deemed to have a substantial effect on the water resources of the basin, such that they must come under DRBC review.

Section 2.3.5A of the RPP enumerates nineteen classes of projects that are deemed not to have a substantial effect on the water resources of the Basin and therefore are not required to be submitted for Commission Review, “except as the Executive Director may specially direct by notice to the project owner or sponsor, or as a state or federal agency may refer under paragraph C. of this section.”

Section 2.3.5B of the RPP specifies that “[a]ll other projects which have or may have a substantial effect on the water resources of the Basin shall be submitted to the Commission in accordance with these regulations for determination as to whether the project impairs or conflicts with the Comprehensive Plan.” That section lists eighteen classes of projects that require Commission review unless otherwise exempted by Section 2.3.5A of the RPP.

In defining the last of these enumerated classes, Section 2.3.5B.18 of the RPP states: “Any other project that the Executive Director may specifically direct by notice to the project sponsor or land owner as having a potential substantial water quality impact on waters classified as Special Protection Waters.”

Furthermore, Section 2.3.5C of the RPP enables federal and state agencies to refer otherwise-excluded projects to the Commission for action as follows:

Whenever a state or federal agency determines that a project falling within an excluded classification (as defined in paragraph A. of this section) may have a substantial effect on the water resources of the Basin, such project may be referred by the state or federal agency to the Commission for action under these Rules.

DRBC Assertion of Jurisdiction over Oil and Gas Well Projects

Oil and gas well projects are subject to DRBC review based on the directives of the DRBC Executive Director and referrals from federal agencies.^a

Executive Director's Determination of May 19, 2009

On May 19, 2009, Defendant Carol Collier, in her official capacity as Executive Director of the DRBC, issued her "Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations with the Drainage Area of Special Protection Waters" ("EDD").

In the EDD, Ms. Collier found that shale formations targeted for horizontal drilling and hydraulic fracturing are within the drainage area to Special Protection Waters to the Delaware River Basin and accordingly, "as a result of water withdrawals, wastewater disposal and other activities, natural gas extraction projects in these shale formations may individually or cumulatively affect the water quality of Special Protection Waters by altering their physical, biological, chemical, or hydrological characteristics."

Therefore, citing to RPP Section 2.3.5B.18, Ms. Collier notified natural gas extraction project sponsors that "they may not commence any natural gas extraction project located in shale formations within the drainage area of Special Protection Waters without first applying for and obtaining Commission approval." The EDD defined "project" to include "the drilling pad upon which a well intended for eventual production is located, all appurtenant facilities and activities related thereto and all locations of water withdrawals used or to be used to supply water to the project."

The EDD stated that "[t]he Commission recognizes that each natural gas extraction project will also be subject to the review of the environmental agency of the state or Commonwealth in which the project is

^a Proposed gas well projects are also subject to DRBC review and evaluation pursuant to Water Code §2.20.6, which provides that "[t]he underground water resources of the Basin shall be used, conserved, developed, managed, and controlled in view of the needs of present and future generations, and in view of the resources available to them. To that end, interference, impairment, *penetration*, or artificial recharge shall be subject to review and evaluation under the Compact." (emphasis added).

located and in some cases, to federal agency review.” Thus, the project approval to be required by the Commission is in addition to any applicable state and/or federal permitting requirements.

The EDD, however, specifically excluded wells to be drilled for exploration and not production: “Wells intended solely for exploratory purposes are not covered by this Determination.”

At its public meeting on May 5, 2010, the DRBC directed commission staff to draft regulations for natural gas well pad projects in shale formations in the Delaware River Basin. See Compact Section 5.2. (“[t]he commission may assume jurisdiction to control future pollution ... in the waters of the basin, whenever it determines ... that the effectuation of the comprehensive plan so requires. The standard of such control shall be that pollution by sewage or industrial or other waste originating within a signatory state shall not injuriously affect waters of the basin as contemplated by the comprehensive plan”).

National Park Service Referral

The National Park Service, a federal agency within the U.S. Department of the Interior, manages the Upper Delaware Scenic and Recreational River, the Delaware Water Gap National Recreation Area, and the Middle Delaware National Scenic and Recreational River.

On May 26, 2010, Sean J. McGuiness, Superintendent of the Upper Delaware Scenic and Recreational River, sent a letter to Executive Director Collier regarding “Exercise of Project Review Jurisdiction Over All Natural Gas Wells, Including Exploratory Wells, in the Area Draining to Special Protection Waters in the Delaware River Basin” (NPS Referral Letter).

Explicitly invoking the authorities of Section 3.8 of the Compact and RPP Sections 2.3.5A and C, Superintendent McGuiness referred to the Commission “all projects that involve drilling of natural gas wells that are not already subject to project review under the Commission’s regulations” and the EDD.

The NPS Referral Letter explicitly stated: “This referral includes both ‘exploratory’ or ‘test’ wells, and wells completed in a geological strata other than shale, and it extends to all aspects of natural gas development that involves land disturbance or water use from the proposed construction of exploratory wells to gas distribution pipelines.”

Superintendent McGuiness explained the significant concerns with the impacts of so-called exploratory or test wells to the Special Protection Waters of the Delaware River Basin as follows:

The decision to exclude exploratory wells may have been based largely on the fact that these ‘test’ wells will, for the most part, not require hydrofracturing, and will each require less than the 100,000 gallon threshold for consumptive use that requires project review under the compact in accordance with the DRBC Rules of Practice and Procedure. Yet, experience with natural gas development in the region has shown that a very large

percentage of ‘exploratory’ wells are eventually converted to production wells. Thus, the DRBC will have little or no influence over the location of these projects if they’re proposed at pre-existing ‘test’ well sites. This could result in projects having greater environmental impacts, or in the denial of permits which might otherwise have been approved if the projects had been located in less environmentally sensitive areas.

Supplemental Executive Director’s Determination of June 14, 2010

On June 14, 2010, Ms. Collier issued a “Supplemental Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters” (SEDD). The SEDD withdrew the exclusion for exploratory wells of the May 2009 EDD and extended the provisions of the EDD to include exploratory wells.

The SEDD stated:

I am specially directing all natural gas well project sponsors, *including the sponsors of natural gas well projects intended solely for exploratory purposes*, that they may not commence any natural gas well project for the production from or exploration of shale formations within the drainage area of Special Protection Waters without first applying for and obtaining Commission approval. (emphasis in original).

In support of this decision to bring all exploratory gas wells under the DRBC’s jurisdiction via the project approval process, the SEDD:

recognize[d] the risks to water resources, including ground and surface water that the land disturbance and drilling activities inherent in any shale gas well pose. . . . [T]his Supplemental Determination removes any regulatory incentive for project review sponsors to classify their wells as exploratory wells and install them without Commission review before the Commission’s natural gas regulations are in place. It thus supports the Commission’s goal that exploratory wells do not serve as a source of degradation of the Commission’s Special Protection Waters.

Fish & Wildlife Service Referral of June 25, 2010

On June 25, 2010, Marvin Moriarty, Acting Northeast Regional Director of the U.S. Fish and Wildlife Service (FWS), and Dennis Reidenbach, Northeast Regional Director of the National Park Service, sent a joint letter to Ms. Collier regarding the SEDD.

Although Regional Directors Moriarty and Reidenbach strongly supported the decision to subject exploratory wells in the drainage area of Special Protection Waters to DRBC jurisdiction and regulation, they objected to Ms. Collier’s decision to grandfather wells already approved by PADEP without further DRBC review.

The Referral Letter from the NPS and FWS Regional Directors pointed out that the environmental effects of exploratory and production wells are almost the same:

With the exception of activities related to hydraulic fracturing (for increasing production), the environmental effects of natural gas well construction, either as a 'production' well as an 'exploratory' well, or into shale or non-shale formations, is virtually identical. Each drilling project involves construction of a well pad and associated roadways, the drilling of a well bore, the withdrawal and transport of surface or groundwater, and the recovery and handling of flow-back water and drilling fluids. As stated in your May 19, 2009, Executive Director's Determination, 'Each of these activities, if not performed properly, may cause adverse environmental effects, including effects on water resources.' (emphasis added).

The FWS and NPS Regional Directors further emphasized the industry practice of converting exploratory wells to production wells, underscoring the critical need for environmental review prior to any well pad construction and development:

Additionally, it appears to be industry standard to convert exploratory or test wells to full production wells if suitable gas deposits are encountered. Based on our discussions with PADEP staff working on Marcellus permitting in southwestern Pennsylvania, we concluded that exploratory wells fall into two general categories. A small number of wells (e.g., one to two per county) are drilled during the initial phase of expansion into a new area and are truly exploratory wells intended to optimize drilling practices for the new area. The second and larger category of 'exploratory' wells includes wells drilled during subsequent expansion into an area. Only a very small percentage of these wells are abandoned without being converted to a production well. In fact, Pennsylvania regulations do not distinguish between exploratory and production wells for State-issued permits. The high rate of exploratory-to-production well conversion, the environmental effects common to both, and the cumulative effects are of concern to the Services.

The Referral Letters by NPS dated May 26, 2010 and by NPS and FWS dated June 25, 2010, respectively operated as referrals under RPP 2.3.5A and 2.3.5C.

General Comments

The Draft Regulations' Deference to and Deferral to the States is Inconsistent with the Compact

The Compact contains express requirements that the parties to the Compact engage in a joint exercise of authority, with a coordinated programs and uniform standards. The Draft Regulations run counter to these requirements.

The relevant provisions of the Compact follow:

Section 1.3.(b) The water resources of the basin are subject to the sovereign right and responsibility of the signatory parties, and it is the purpose of this compact to provide for a ***joint exercise of such powers*** of sovereignty in the common interests of the people of the region.

Section 1.3.(c) The water resources of the basin are functionally interrelated, and the uses of these resources are interdependent. A single administrative agency is therefore essential for effective and economical direction, supervision and ***coordination of efforts and programs*** of Federal, state and local governments and of private enterprise.

Section 1.3.(e) In general, the purposes of this compact are to promote interstate comity; to remove causes of present and future controversy; to make secure and protect present developments within the state; to encourage and provide for the planning, conservation, utilization, development, management and control of the water resources of the basin; ***to provide for cooperative planning and action by the signatory parties with respect to such water resources; and to apply the principle of equal and uniform treatment to all water users who are similarly situated and to all users of related facilities, without regard to established political boundaries.***

Section 3.1. Purpose and Policy. The commission shall develop and effectuate plans, policies and projects relating to the water resources of the basin. ***It shall adopt and promote uniform and coordinated policies*** for water conservation, control, use and management in the basin. It shall encourage the planning, development and financing of water resources projects according to such plans and policies.

(emphases added). See also Water Code §3.10.3.f:

The Commission shall, to the extent practicable and necessary, coordinate and oversee all Special Protection Waters activities and assist the efforts of each state environmental agency to control pollutants originating from intrastate tributary watersheds. The Commission shall determine pollution control requirements for discharges to Special Protection Waters; for non-point sources draining directly into Special Protection Waters; and total non-point source loads emanating from intrastate tributary watersheds as measured at Boundary Control Points.

The Draft Regulations largely reflect an abandonment of joint sovereignty, which will likely lead to uncoordinated and divergent policies, unequal treatment based on political boundaries, and a greater likelihood of interstate controversy. The DRBC must, through revisions to the Draft Regulations, establish a uniform floor that ensures no measurable change in water quality results from gas development projects, except toward natural conditions. This must be a meaningful set of standards below which no gas development project in the Basin can fall.

Reliance on State Regulators Fails to Meet the DRBC's Responsibilities

The Draft Regulations rely on state regulators even though DRBC staff has acknowledged that it has not conducted any review of the adequacy of state-level oversight.^b

As DRN has established through the discovery process in a pending case before the Pennsylvania Environmental Hearing Board, Pennsylvania's permit review process is woefully inadequate. The case Damascus Citizens for Sustainability, Inc. v. PA DEP, EHB Docket No. 2010-102-M, concerns the Woodlands Management project in Damascus Township, Wayne County, PA. The Woodlands project is located within the "Hollister Creek" watershed, a designated "Special Protection High Quality" (HQ) watershed and is approximately 300 feet from Hollister Creek. The project is also within the Upper Delaware River Basin and is approximately 0.43 miles from the Delaware River, an area within the Upper Delaware Scenic and Recreational River, a National Wild and Scenic River. The personnel from PA DEP who were responsible for approval of the permit admitted that the Department did not consider the potential impacts on the high quality watershed in which the project is located. (Lobins Dep. at 33-34, 45-46, 49-51; Babb Dep. at 31, 38, 52-53; Lichtinger Dep. at 9, 17, 29, 39-41). They also admitted that the Department did not consider the potential impacts on the Delaware River or the Delaware River Basin. (Lobins Dep. at 46-48, 51-52; Babb Dep. at 53-55; Lichtinger Dep. at 9, 10, 29, 37-40). For a more detailed description of the testimony of the responsible DEP officials, see the April 12, 2011 letter of Jordan B. Yeager, Curtin & Heefner LLP submitted on behalf of DRN.

Inadequate Runoff and Erosion Control Provisions Violate the Compact

In addition to its general requirements that water quality be maintained and that pollution be prevented, the Compact contains specific provisions that obligate the DRBC to control runoff and soil erosion. Article 7, Section 7.1 mandates that "The commission shall promote sound practices of watershed management in the basin, including projects and facilities to retard runoff and waterflow and prevent soil erosion."

Consistent with the requirements of the Compact, the Water Code, §2.150.2 (Resolution No. 71-13) mandates that "[a]ny project within the jurisdiction of the Commission which involves a significant disturbance of ground cover shall include sound practices of excavation, sediment retention, backfill, and reseedling to minimize soil erosion and deposition of sediment in streams." See also Water Code §3.10.3.a.2.e. ("Projects subject to review under Section 3.8 of the Compact that are located in the drainage area of Special Protection Waters must submit for approval a Non-Point Source Pollution Control Plan that controls the new or increased non-point source loads generated within the portion of the project's service area which is also located within the drainage area of Special Protection Waters").

The Draft Regulations' failure to impose meaningful oversight of stormwater runoff and erosion control violates the requirements of the Compact and the Code.

^b For example, in a briefing on February 17, 2011, commission staff acknowledged that the DRBC had not conducted a review of Pennsylvania DEP's permit review process.

Inadequate Planning Is Counter to the Requirements of the Compact and the Water Code

The DRBC's refusal, to date, to allow the science of a cumulative impact study inform its Draft Regulations is counter to the Compact's emphasis on planning. Article 13, Section 13.1 of the Compact contains the requirement for a Comprehensive Plan "for the optimum planning, development, conservation, utilization, management and control of the water resources of the basin to meet present and future needs." Similarly, Section 13.2 requires an annual water resource program that includes, "a systematic presentation of ...the quantity and quality of water resources needs for such period..." The failure to conduct a study of the cumulative impact of drilling in the basin makes any evaluation of and planning for the water resource needs an empty gesture.

This failure to plan is particularly glaring in light of the DRBC's failure to satisfy the requirements of Section 3.3.10.3.e.3 of the Water Code, which mandate:

Within two years after the adoption of Special Protection Waters non-point source control regulations, the Commission shall, after substantial consultation with local, county, state and federal agencies and the general public, publish a report presenting its methodology for prioritizing watersheds in the Special Protection Waters drainage area including alternatives, if any; a preliminary listing of priority watersheds in the drainage area; and a recommended plan of study for the development of watershed-specific management plans. For waters classified as Special Protection Waters after December 1992, the watershed prioritization process will be completed within two years after the Special Protection Waters are classified. Watershed priorities will be determined from a comparative analysis of each watershed's location and potential, future impact on existing water quality at designated Boundary and Interstate Control Points. In determining priorities, the Commission will consider:

- (a) the physical characteristics of the watershed including slopes, soils, existing land use and land cover, drainage characteristics, and others;
- (b) the status of existing water quality and trends, if any, of the watershed as measured at its Boundary Control Point;
- (c) the anticipated mass loadings of new non-point sources;
- (d) the watershed management and planning priorities of applicable local, state and federal agencies;
- (e) the current status of local land use/non-point source controls in the watershed;
- (f) the stormwater permitting activity in the NPDES permitting program; and
- (g) other natural and anthropogenic factors.

4) Once the public has been given an opportunity to comment, the Commission will adopt a list of priority watersheds. This listing will be reviewed and modified as necessary on a two year basis after adoption.

5) Within five years after adopting a list of priority watersheds draining to Special Protection Waters, the Commission shall develop, or encourage the development of, watershed non-point source management plans for each priority watershed unless new circumstances result in deferring plan completion. Watershed nonpoint source management plans will focus on non-point source loadings, but will consider total loads including both point and nonpoint sources and their interrelationship where necessary. During plan development, the Commission will seek technical assistance from the applicable state environmental agency and all other applicable federal, state, county, and local governmental units; and will consider direct delegation of plan development (with concurrence of the state environmental agency) to any county or other applicable governmental entity desiring to perform the watershed planning activities on behalf of, or instead of, the Commission. Where more than one political unit shares a watershed, joint plan development arrangements between the Commission and delegated agencies will be developed.

The DRBC has simply failed to do the analysis and planning that the Compact and Water Code require.

The DRBC Must Conduct a Comprehensive Cumulative Impacts Analysis

We support the Commission in its goal of developing natural gas development regulations in the Delaware River Basin. We recognize the importance of natural gas regulation and consider the Commission's role as the representative of the joint governance of the States and the federal government in regulating natural gas development as paramount and appropriate, considering its statutory responsibilities and regulatory obligations regarding water resource management in the Basin. Adequate regulations based on a comprehensive environmental assessment are essential to protect the water supply for over 15 million people and to assure that the Delaware River's Special Protection Waters (SPW) and all the Basin's water resources are protected from pollution and degradation. The Commission's Draft Rules do not achieve the goal of preventing pollution, avoiding degradation, and helping to improve where needed the water resources of the Basin.

The Commission recognized the potential cumulative impacts of natural gas development on the water resources of the Basin to be so significant that the Commission applied for federal funding for a cumulative impact study. The U.S. House of Representatives Appropriations Committee Subcommittee on Interior, Environment, and Related Agencies approved \$1 million for the U.S. Geological Survey (USGS) and the Commission to conduct that study but due to the lack of needed action on the federal budget, these funds were not granted in the last Congressional session. The foresight the Commission has shown in seeking these funds is exemplary. We understand that the Commission is still interested in

pursuing a cumulative impact study for the Basin and has sought other sources of funding. We are in full support of this effort and have continued to seek funding sources for the Commission ourselves.

The Commission's Water Resources Program FY2010-2015 (WR Program) calls for the Commission to "Perform Cumulative Impact Analysis on water supply 2011-2012 Funding permitting" (DRBC 2010b, p. 17) under its Natural Gas Development regulation program. The lack of a cumulative impact analysis undermines the Commission's ability to implement effective and sufficiently protective regulations¹. (Daniels p. 6) Daniels also points out that the Commission's WR Program states that "Additional demand for use in energy exploration, e.g. natural gas drilling, is increasing, although the full effect of this demand sector has yet to be identified" (DRBC 2010b, p.4) and "There will need to be more analysis of the water needs for energy projects and energy needs for water treatment as well as an evaluation of the carbon and water footprints" (DRBC 2010b p.11). Daniels concludes (Daniels p. 18):

In other words, the Commission does not have a good sense of the potential cumulative impact of up to tens of thousands of natural gas wells on water withdrawals and on ground water and surface water quality from the use of fracking chemicals. These shortcomings are reflected in the lack of mention in the proposed Natural Gas Regulations of assessing cumulative impacts in the process of deciding whether the Commission should approve a natural gas well or a Natural Gas Development Plan of several wells.

Sound watershed management requires assessing the potential cumulative environmental impacts of individual wells and Natural Gas Development Plans in the Delaware River Basin, especially in those areas that have been designed as Special Protection Waters and in forested areas where deforestation could cause erosion and sedimentation and thus reduce water quality and aquatic habitat. A case-by-case review of development proposals is not sufficient given the large number of applications for wells anticipated over the next several years. The Commission should explain in its regulations and Comprehensive Plan how the cumulative impact of so many wells will be anticipated, measured, and scientifically monitored, and how the existing and potential cumulative effects of well drilling will be considered in the approval of individual natural gas wells and Natural Gas Development Plans.

The impacts of hydraulic fracturing on the subsurface geology and ground water resources in the Delaware River Watershed are unknown and have not been studied or modeled by the Commission or any other agency. A cumulative impact analysis or environmental study should be completed to assess the subsurface changes that would occur and the resulting environmental impacts.

There is tremendous debate over the safety of hydraulic fracturing where it is being used. The large number of incidents of pollution, methane gas migration, blowouts and other problems throughout Pennsylvania is well documented by PADEP.

(see www.dep.state.pa.us/dep/deputate/minres/oilgas/OGInspectionsViolations/OGInspviol.htm).

Given the irreplaceable nature of the Delaware River's SPWs and the Basin's water supply reservoirs, Demicco² recommends at least a 10-year research period for this relatively new technology in deep geologic formations before any gas development begins in these vulnerable areas. (Demicco, p. 5)

One of the most disturbing aspects of the Draft Rules is the obvious lack of information about the watershed and the lack of data about the expected impact of gas development. Parasiewicz states that this information, gathered through an impact analysis, would serve as a foundation for the decision-making process and regulations. It is surprising that, in an area of high ecological importance and the presence of powerful economic interests (New York City, Philadelphia, utilities and the mining industry), there is no comprehensive model of the watershed allowing for the simulation of future scenarios. Parasiewicz points out such models have been developed and implemented in other areas, including the Michigan Water Withdrawals Assessment Tool (<http://www.miwwat.org/>), which could be a starting point for more accurate models to be applied in the Delaware River Watershed. (Parasiewicz p. 14-15).

Unfortunately, the Commission issued draft natural gas regulations in December without the benefits of the findings of such a study. In our opinion, a cumulative impact analysis of the potential effects of natural gas development on the Basin's resources is essential to developing appropriate rules that will fulfill the DRBC's mandates. We consider the Draft Rules lacking in the critical limits and management policies that this analysis would provide. In addition to specific deficiencies detailed in this comment, this is an inescapable fatal flaw in the Draft Rules.

The DRBC is Required to Prepare a Full Environmental Impact Statement Pursuant to NEPA Before Issuing Final Drilling Regulations

The National Environmental Policy Act ("NEPA"), the nation's bedrock environmental law, seeks to ensure sound policy making by requiring that federal agencies evaluate the potential adverse impacts of their proposed activities before undertaking them. To achieve this goal, NEPA requires the preparation of an environmental impact statement for all "major Federal actions significantly affecting the quality of the human environment." 42 U.S.C. § 4332(2)(C). There can be no doubt that the DRBC is a federal agency subject to the requirements of NEPA. The language of the DRBC Compact itself provides that the Commission is a federal agency and thus subject to NEPA, stating that the "compact shall not enlarge the authority of any federal agency other than the commission." DRBC Compact, §15.1(o) (emphasis added). The Council on Environmental Quality's ("CEQ") regulations for NEPA also recognize DRBC as one of the "federal or federal-state agencies with jurisdiction by law" over NEPA issues, alongside the United States Environmental Protection Agency and numerous other federal agencies. NEPA Implementation Procedures, Appendix II, 49 Fed. Reg. 49750 (December 21, 1984).

Further, the issuance of regulations governing new gas development within the Delaware River Basin is plainly a major federal action for purposes of NEPA. The CEQ regulations define a "major federal

action” as an action “with effects that may be major and which are potentially subject to Federal control and responsibility,” and such an actions involve “new and continuing activities, including projects and programs entirely or partly financed, assisted, conducted, regulated, or approved by federal agencies; new or revised agency rules, regulations, plans, policies, or procedures . . .” 40 C.F.R. § 1508.18. By this definition, the issuance of these regulations is clearly a major federal action because it creates a new program that adopts new agency rules and regulations, and is partly financed, regulated and approved by the DRBC and by the Army Corps of Engineers, the DRBC’s federal member.

Moreover, for all the reasons set forth below and in the accompanying expert reports, regulation of new gas development within the Delaware River Basin is an activity that has the potential to have significant environmental effects. As such, it is evident that the DRBC is bound, subject to NEPA, to prepare a full environmental impact statement (“EIS”) evaluating the range of potential adverse environmental impacts of its proposed regulatory program before issuing new regulations governing gas development within the Basin. 42 U.S.C. § 4332(2)(C); 40 C.F.R. §§ 1502.4, 1508.18. Nonetheless, the DRBC has issued its draft regulations without undertaking any NEPA environmental review measures whatsoever.

The purpose and benefits of NEPA’s requirements are clear. NEPA’s EIS requirement aims “to ensure both that an agency has information to make its decision and that the public receives information so it might also play a role in the decisionmaking process.” Dep’t. of Transportation v. Public Citizen, 541 U.S. 752 (2004). The statute is intended to insure that environmental concerns are integrated into the very process of agency decision-making. Andrus v. Sierra Club, 442 U.S. 347 (1979); [Lower Alloways Creek Tp. v. Public Service Elec. & Gas Co.](#), 687 F.2d 732 (3d Cir. 1982). When the federal government conducts an activity, NEPA imposes procedural requirements to ensure that in making decisions, an agency will have available, and will carefully consider, detailed information concerning environmental impacts. To issue detailed regulations for new gas development in the Delaware River Basin without having reviewed the potential environmental impacts that may result therefrom is not only short-sighted but unlawful, and is likely to result in flawed and incomplete regulation of this risky industrial activity.

Regulatory Responsibility Must Be Clarified

The Commission has included provisions in the Draft Rules that are not included in the regulations of the host states. For example, Section 7.3(K) governing financial assurance, including bonding, assumes the Commission has this authority. The Commission should provide clarity that the proposed Article 7 will be enforced in the Delaware River Basin drainage areas that are located in all the Basin states³. (Miller, p. 1) How this requirement will be carried out also needs to be addressed.

Planning Must Be Completed Before Natural Gas Development Regulations

Flexible Flow Management Plan

The Commission is in the process of developing a rulemaking for the Flexible Flow Management Plan (FFMP) for the Delaware River.⁴ DRN points out that the FFMP needs to be completed before any natural gas related projects are approved. While the FFMP applies to releases from the New York City reservoirs and affected waters, the flows of the main stem River are directly fed by all of its tributaries. Also, it has been stated that the methods and policies that are part of the FFMP program, such as the application of an “ecoflow” model to set flows, will be used throughout the Delaware River Watershed. The efforts of the states of Delaware, New Jersey, New York, Pennsylvania and the City of New York to agree to an operating regime for releases from the three New York City reservoirs in the upper Delaware River Basin and to resolve conflicts about equitable apportionment of those watersheds are ongoing, and include establishing necessary flows for the protection of instream life, notably the world-class trout fishery and the federally endangered dwarf wedgemussel.

A new, one year extension of the Flexible Flow Management Plan is expected to be agreed upon by May 31, 2011, without, however, consideration of how the amounts of water projected to be withdrawn for natural gas development will affect the Plan’s goals.

Will water for natural gas development trump these efforts or make meeting present goals and uses more difficult, costly, or impossible? Will other withdrawals eat into the efficacy of the FFMP’s reservoir releases? And at whose expense? These questions need to be answered by a cumulative analysis of impacts of the development of natural gas in the Basin and by the prioritization of the development of an FFMP that is based on ecological flows that protect riverine species.

There has been no public discussion of these issues and the Commission has put rulemaking for the FFMP on hold, removing the public from the process and leaving the planning to the Supreme Court Decree Parties, behind closed doors, labeled as decree “negotiations”. Before natural gas regulations are approved, the FFMP should be evaluated as to how flow management and gas development will interplay and how these will impact the ecology and species of the Delaware River. A plan should be developed that provides a calculation of how much total water can be removed without degrading SPW resources and the unique habitats of the Watershed. Also, location of withdrawals, rate and timing of withdrawals, pass-by flow requirements and stream and river flow regimes, nonpoint source pollution control plans and other aspects of Dockets can be informed by an analysis of tributary and main stem flow regime needs. This is essential to prevent water resource depletion and the disruption of the flow regimes that now support species and ecosystems of the River and its Watershed.

Water Resources Plan for the Delaware River Basin

The Commission spent considerable resources on developing the Water Resources Plan for the Delaware River Basin⁵ which was adopted by the Commission in 2004. A unanimous resolution was adopted September 29, 2004 by the Commission in support of the Plan. Yet the Plan has never been adopted into the Commission’s Comprehensive Plan. This is a gaping oversight. There has been no

public discussion about why this critical planning effort did not result in this Plan being incorporated into the Comprehensive Plan; indeed the public views the Plan as a successful planning process with important purpose. The updating of the Comprehensive Plan is a crucial step that must be taken by the Commission before the Draft Rules are adopted. Daniels refers to the Water Resources Plan as the key guiding document that informs the Commission's decisionmaking and reflects modern planning efforts that are essential to successful water management of the Basin by the Commission. (Daniels, p.6, 8)

Ecological Flow Planning and Habitat Modeling Needed

The Commission has been developing an ecological flow regime approach to stream flows for several years. A resolution of the Decree Parties formed a committee of scientists that have been working on developing a flow model that will be used throughout the Watershed to help set stream flows that protect the habitat needs of streams. The River Master website reports that on the committee's formation⁶:

Formation of the Subcommittee on Ecological Flows (SEF)

Resolution No. 2003-18 formalized a process for developing and evaluating the feasibility of achieving flow targets to address instream flow and freshwater inflow requirements for aquatic ecosystems in the Delaware River Basin, including the Delaware Bay. It also established a Subcommittee on Ecological Flows (SEF) to assist the DRBC's RFAC (and formerly, the FMTAC) in developing scientifically-based ecological flow requirements for the maintenance of self-sustaining aquatic ecosystems.

The Commission and the Decree Parties committed to participating in a non-binding collaborative process to develop experimental flow management options for the Delaware River and its regulated tributaries. The objectives include development of scientifically-based ecological flow requirements, objective recreational needs assessments, a review of the estuary salinity objective, and an assessment of existing and future municipal, industrial and other water supply needs.

The purpose of the SEF is to assist in developing scientifically-based ecological flow requirements. The SEF provides regular progress reports to the RFAC and works with the DRBC's RFAC and the Water Management Advisory Committee (WMAC) in a collaborative way. Membership of the SEF includes at least one member of the RFAC who is a Decree Party member and at least one member of the WMAC who is not a Decree Party member.

Parasiewicz discusses the importance of the habitat model and the need for the development of an "Ecoflow" approach to setting stream flow targets and regimes. (Parasiewicz p. 6-16) This is discussed at length in this comment under Section 7.4. As far as planning is concerned, the Commission must complete this modeling process to put in place the criteria that would be used to set stream flows. Parasiewicz points out, for instance, that many knowledge gaps indicated in the Commission's Water Resource Management Program need to be completed to provide a foundation for sound scientifically based decisionmaking by the Commission. He suggests the "reference river concept", for example, as critical to management because it establishes a baseline for determining the degree to which a river deviates from optimal conditions. This provides reliable information about how to restore and conserve

the river and is essential to avoid costly mistakes or neglect that leads to endless deterioration. (Parasiewicz p. 11) These concepts and the need for this approach can be found in a 2001 published report prepared for Trout Unlimited which was not included in the Commission's Program but should be.⁷ Without a regulatory framework that requires stream flows, including minimum flows, to be set based on ecological needs and habitat conditions, the Commission's decisions employing the Draft Rules will damage and, for certain sensitive species such as the federally endangered dwarf wedgemussel, may destroy habitat and populations of these species in the Basin. This scientific research and planning effort must be completed and policies adopted to implement the findings prior to finalizing the Draft Rules.

Water Quality Reporting and Stream Monitoring Reports and Remedial Plans Needed

The need for monitoring is discussed at length in this Comment under Section 7.5 and 7.6 and several recommendations are made and incorporated herein in the Expert Reports that accompany this Comment. Baseline data collection is a crucial and urgent step that must be taken by the Commission so that planning and modeling can be out in place to protect water resources and the living resources of the Watershed. The Commission samples water quality and conducts benthic monitoring in the River. However, funding is sorely needed to restore some monitoring that has been cut back in recent years and to expand existing monitoring. Miller recommends that baseline conditions for the entire river system be collected and databanked so that, if gas development moves ahead, monitoring of the relevant constituents can be conducted on a long term basis. Miller recommends that the Commission establish a 30 year (minimum) program that would be funded going forward by the natural gas industry. (Miller, p.4) If pollutants are found then the responsible party must be required to address the problem – robust data is critical to being able to demand accountability. Additionally, sediment sampling is a critical component of sampling that is not presently conducted and should be because many pollutants tend to bind to soil and concentrate there. This is especially important below wastewater treatment facilities, facilities where waste solids and cuttings are being placed, and natural gas well sites where sediment should be sampled for gas drilling wastewater constituents.

Section-by-Section Comments

Section 7.1 Purpose, Authority, Scope and Relationship to other Requirements and Rules.

Section 7.1(a) Purpose. The goal of improving and enhancing the Basin's waters is a basic principle that underlies the provisions of its regulatory framework. Therefore, this section's stated purpose, "...to prevent, reduce or mitigate depletion and degradation of surface and groundwater resources and to promote sound practices of watershed management including control of runoff and erosion," is not complete.

Under the anti-degradation provisions of the federal Clean Water Act's implementing regulations, 40 CFR 131.12 (40 FR 51400 Nov. 8, 1983), "Existing instream water uses and the level of water quality necessary to protect the existing uses shall be maintained and protected". The DRBC's Water Code states this goal at 18 CFR PART 410 Section 3.10.2 and 3.10.3 for Interstate Waters and Special Protection Waters. Throughout the Commission's guiding documents, "optimum" management and enhancement for now and into the future are hallmarks of the Commission's work. As stated in the Resolution approved unanimously by the Commission members in 2004 for the implementation of the Commission's Water Resources Plan, the Commission adopted "[a] Common Vision for a Common Resource (Basin Plan) which lays out policy direction for the use, protection, and enhancement of the Basin's water resources through the year 2030". And the Commission's Comprehensive Plan states the purpose is "to facilitate the optimum planning, development, conservation, utilization, management and control of the water resources of the Basin to meet present and future needs" (DRBC 2010a, p. 3), as discussed in Daniels⁸ (p. 4-5).

The Commission also includes in its 2004 Water Resources Plan for the Delaware River Basin, a guiding principle for "preservation and enhancement of ecological integrity"⁹, as discussed in Parasiewicz¹⁰ (p. 9). As discussed in Daniels¹¹, the Commission's goals and responsibilities as expressed in its statutes and planning documents require that all waters of the Basin be protected and conditions improved where needed.

Therefore, the Purpose should be expanded to embrace the goals of anti-degradation for all of the basin's waters including but not limited to Special Protection Waters, and the goal of enhancing and improving water quality and ecological conditions. It is a ratcheting down of the high purpose of the Commission to describe "to prevent, reduce or mitigate" as the Purpose of the proposed section.

Section 7.1(b) Authority. See DRN comment above.

Section 7.1(c) Scope. We support the inclusion of all natural gas development regardless of target geologic formation. The impacts from natural gas development are substantial for all formations so the Commission is correct to not limit regulation based on geology. We also support the regulation of water withdrawals, well pad and related activities, and wastewater processing/disposal activities.

The Scope should also include gas development infrastructure such as "feeder" or "gathering" low pressure small diameter pipelines that transport raw natural gas from the well head to the processing plant. These pipelines are not regulated by other agencies and operate without government regulatory standards, are not required to be inventoried and mapped by any agency, and pose substantial safety and water quality risks and hazards. The Commission should include these gathering lines within its regulatory scope.

The Scope should include the production gas lines that transport natural gas to market. These are interstate and intrastate pipelines governed by various agencies but not assessed in terms of Basinwide impacts for the Delaware River Watershed. Processing plants, compressor stations, storage facilities, chemical storage facilities, large water holding facilities and impoundments, and other natural gas related infrastructure impose a large footprint of impacts on the Basin and the Basin's resources. Harvey recommends that the Draft Rules address the siting and construction of processing facilities, pipelines, and compressor stations as well as the potential need for additional power generation and waste handling facilities to support this new development. (Harvey, p. 12) The Commission should consider including all parts of the natural gas infrastructure in its regulatory code in order to accurately capture all sources of water-related impacts related to natural gas extraction, development, and production. Without this, the Commission will be taking a piecemeal regulatory approach that will not include all parts of the puzzle needed to address the potential for substantial impacts to water quality.

The Scope should include provisions for addressing the potential for liquid hydrocarbon exploration and production. These impacts can be significant and can contaminate the environment during production or in transport, as discussed in Harvey.¹² Natural gas reservoirs can also produce condensate or natural gas can be found in solution in an oil reservoir and oil reservoirs can be penetrated during gas exploration. Therefore, these regulations should not be limited to natural gas. The DRBC has provided no technical justification for ruling out the possibility of encountering liquid hydrocarbons and state regulations typically cover only oil and gas exploration and development. The Draft Rule should be changed to reflect this. (Harvey p. 8)

The Scope should be expanded to address both exploration and production of all hydrocarbons equally and the title of the regulations should change correspondingly. (Harvey p. 8) The impacts of exploration for natural gas and other hydrocarbons have the potential to substantially affect the water resources of the Basin, as discussed in detail in the DRN/DCS and DRBC expert reports filed in the Consolidated Administrative Hearings on exploratory gas wells in 2010 and submitted herewith in Attachment 2.

The Scope should establish regulatory requirements for seismic data collection as this can substantially impact water resources in a variety of ways. (Harvey, p. 9-12)

Air emissions impact water resources and the health and ecological integrity of the Delaware River Basin and its regulation should be included in the Draft Rules. Air pollution from gas development has been documented as a major pollution impact, as discussed later in these comments. In addition to human health and wildlife impacts from breathing in polluted air, the deposition of air pollutants onto land, vegetation and water surfaces delivers nonpoint source pollution to the Basin's waterways and water supplies. Harvey describes that hydrocarbon evaporation and burning as well as aerosol particles of unburned fuel can cause atmosphere pollution. Aerosol particles can include nitrogen oxides, sulfur oxides, carbon monoxide, particulate matter, and hazardous air pollutants. Harvey explains (Harvey p. 23-24):

Airborne pollutants can be transported downwind and deposited on water and land surfaces. These impacts are not well understood or mitigated. DRBC's regulations should restrict flaring, venting, and fugitive emissions to the lowest technically feasible level. Green completion methods should be required to capture methane emissions, especially where high-volume fracture treatments and well tests are planned.

We support Harvey's recommendation of "green completion" methods. She elaborates that methane capture, in most cases, has the added benefit of capturing benzene, a known human carcinogen, and other hazardous air pollutants that are contained in natural gas. (Harvey p. 24). Harvey also illustrates the connection between air and water in the report she prepared for the DRBC Administrative Hearing¹³.

Methane pollution and greenhouse gas releases from natural gas development significantly contribute to air degradation from natural gas, whether during stimulation and production or during transport, where pipeline leakage is a mounting problem. The Commission's W.R. Program, as cited in this Comment under Section under General Comments, includes the need for analysis of water and carbon footprints and of energy needs in the Basin. Methane and greenhouse gas from gas development is being studied today. Robert W. Howarth, Renee Santoro and Anthony Ingraffea published a scientific paper on methane and climate change gases from natural gas development in April, 2011¹⁴. See **Attachment 5** Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations", 4.14.11. The Abstract states:

We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the life-time of a well.

These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured -- as methane escapes from flow-back return fluids -- and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

We advocate that Commission address air pollution, methane release and greenhouse gas contributions in the Draft Rules.

Section 7.1(d) Comprehensive Plan and Project Review. We support the Commission's determination that the Commission's Comprehensive Plan requires the regulation of all natural gas development projects. See DRN Comment above.

See Daniels¹⁵ regarding the planning and regulatory functions of the Commission and its required actions, based on the Compact, 1961; the Comprehensive Plan, 2001; the Water Resources Plan for the Delaware River Basin; the Water Resources Program FY 2010-2015; and the Delaware River Basin Water Code, with amendments.

Section 7.1(e) Planning Framework. We agree that the Commission's authority includes regulatory and planning responsibilities as per Articles 5 and 7 of the Compact. We agree that water resources should only be used in a sustainable manner and that pollution of or injury to water resources should be avoided. Key elements of the Commission's planning framework include the National Wild and Scenic River, and the related National Park Service Management Plans, the central management goal of maintaining high water quality, coordinated basinwide water resource management, and the designation and implementation of Special Protection Waters.

We agree that sound scientific watershed-based management is essential and that water resource decisions should: link water quality and water quantity with management of other resources (such as land, air, habitat, and community health); recognize hydrological, ecological, social and institutional systems; recognize the importance of watershed and aquifer boundaries; and avoid shifting pollution from one medium to another or adversely impacting other locations; and push the boundaries of technological possibility. The Draft Rules should be amended at 7.1(e)(3) to require that decisions should be based on scientific principles that use Best Management Practices (BMP) and Best Available Technology (BAT) as most federal regulations require; the Commission does not mention BAT in the Draft Rules. This will allow for continuous improvement as BMP and BAT in gas and oil development improves over time. (Harvey p.22) The Draft Rules should also require that all new technology be fully vetted, tested, and approved by professionals in advance of use; a risk assessment of the use of new technology should be required. Harvey states that the use of new equipment without proper vetting can have catastrophic consequences. (Harvey p. 25)

We do not agree that economic constraints are a consideration for the Commission except in those limited circumstances where the Commission expressly codified the need for social and economic justification. There is no provision in the Compact that allows the Commission to "balance economic constraints against the need to ensure "no measurable change." If, due to economic constraints, a gas drilling project or related use cannot be carried out without making a measurable change in water quality, the Commission does not have discretion to allow it to proceed.

We agree that land management is a crucial part of water resource management. We agree that decision making regarding land management must employ sound scientific principles and requires an

understanding of the relationship between land and water resources. We agree that improving water quality and conditions requires sound land management by all levels of government and that planning efforts can improve how we get this done. This concept supports our contention that the Commission (Section 7.1 (a)) is charged with the goal of improving water quality and conditions where needed and it supports the concept that unless land use changes are addressed, water resource protection and pollution prevention cannot be achieved.

The Draft Rules should preclude project sponsors from potentially compromising groundwater quality in multiple watersheds by extending horizontal projections (well bores) under watershed divides, in regard to 7.1.(e)(2)(iii) and (iv). This may require hydrogeologic analysis of both shallow and deep groundwater flow systems. (Rubin p. 6) The question of whether, for instance, current drilling in the Susquehanna River Watershed is intruding into the Delaware River Watershed by deep underground horizontal well bores, and thereby potentially impacting Delaware River watershed resources, is unknown. This is of particular concern regarding intrusion into off-limit areas or environmentally sensitive areas.

Section 7.1(e)(4) Reliance on host state review and requirements for well construction and operations is unacceptable as it will not ensure that the DRBC's legal mandates under the Compact will be fulfilled. The problems with the Draft Rules' reliance on host state requirements is addressed in DRN's comments under Sections 7.1(f) and (i) and under individual subsequent sections.

Section 7.1(f) Relationship to Other Commission Requirements. The Draft Rules state that the proposed Article 7 "helps to implement the Commission's Special Protection Waters program." The goal of no measurable change to existing water quality from point or nonpoint sources except toward natural conditions in Special Protection Waters cannot be achieved under existing host state regulations. (Demicco, p. 5, Harvey p. 13-16, Miller p. 2, Adams, p. 2, Bishop¹⁶ p. 1, Rubin, p. 3)

Special Protection Waters and other Water Code issues and other Commission requirements are addressed under specific subsequent sections in DRN's comments.

Section 7.1(i) Host State Regulation of Natural Gas and Exploratory Well Construction and Operation. The Commission's Draft Rules conclude that host state regulations (i.e. New York and Pennsylvania) are sufficient to protect the Delaware River Watershed, except regarding water use and waste management and that state regulations address all other impacts of gas well construction and operation. This conclusion is not justified. (Harvey p. 13-16, Miller p. 2, Adams, p. 2, Demicco p. 3-5, Bishop p. 1, Rubin p.1, Daniels, Parasiewicz, p.2)

For example, the Draft Rules do not provide justification as to how host state regulations address the potential for pollution from: chemical spills, fuel spills, well blowouts, hydrocarbon processing activities, pipeline development activities, improper well construction, and improper well operation.

Host state shale gas regulations are not complete or are nonexistent regarding major aspects of gas well development including, well construction and gas extraction, production and operation. Specifically, Pennsylvania (PA) and New York State (NYS) well construction and operation regulations are known to be outdated, incomplete, and not reflective of best technology and best practices for oil and gas exploration and production. (Harvey p, 13-16)

As Harvey explains, Pennsylvania Department of Environmental Protection (PADEP) may complete revisions to Chapter 78 (PADEP's Oil and Gas Well Regulations) in 2011. While PADEP's proposed revisions to Chapter 78 regulations have the potential to be a substantial improvement, they are not yet codified. Even if they are codified, some gaps remain. Chief among these gaps is the absence of any approval process for well construction design to ensure the protection of water resources before a well is drilled and completed (see 2010 HCLLC report on Recommendations for Pennsylvania's Proposed Changes to Oil and Gas Well Construction Regulations and 2010 HCLLC report on the DRBC Consolidated Administrative Hearing on Grandfathered Exploration Wells – attachments to Harvey).

Harvey further explains that New York State is in the process of completing an environmental review for new shale gas development and has not yet determined if they will issue updated regulations or when their review will be completed. However, if regulations are proposed, they are not expected to be implemented prior to 2012. There is wide agreement that existing regulations are inadequate (see 2009 HCLLC report on New York State (NYS) Casing Regulation Recommendations, as well as the 2009 HCLLC report on the Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs, Review of DSGEIS and Identification of Best Technology and Best Practice Recommendations— attachments to Harvey).

Also, ensuring “adequate assimilative capacity” sets too low a bar of protection for living resources and downstream users – first the definition of “adequate” is relative and without definition does not set a clear standard for implementation or enforcement; and the term “adequate” does not provide any level of buffer or protection for changing conditions as it is likely set at a single point in time and fails to account for changing conditions.

Bishop recommends that the Commission wait for the finalization of New York's Supplement to the SGEIS before completing its own Draft Rules. He also recommends that financial and human resources will need to be committed by the Commission to oversee and enforce Commission regulations and to provide host states with assistance. (Bishop p. 2)

Specific inadequacies in the host state regulations are explained by Harvey (p. 14):

Neither NYS nor PA regulations require well casing and cementing plans to be submitted, reviewed, and approved as part of a well permit application. Therefore, host

states do not have an opportunity to intervene in and stop poor practices before work commences. Current regulations only require the submission of an after-the-fact well completion report that documents problems encountered while drilling. Well design flaws or improperly designed and executed hydraulic fracture jobs can be difficult, and in some cases impossible, to remedy after the fact. This problem will not be resolved in the proposed PADEP Part 78 revisions. It is unknown how NYS will handle this issue in its regulatory revision process. The lack of review by host states of drilling and completion applications should be of concern to DRBC.

Absent a state review of well plans, DRBC has no assurance that wells drilled in the Delaware River Watershed will be constructed and completed to a standard protective of the watershed. DRBC will not be able to ensure that an effective drinking water barrier is in place before high-volume fracture treatments are performed. Therefore, DRBC should supplement host state regulations with a requirement that well casing and cementing plans be submitted, reviewed, and approved by DRBC. DRBC should not only evaluate whether a PA or NYS regulation exists; it should also examine whether it is implemented and enforced in practice. There are some host state regulations on the books that as currently administered by the state do not adequately protect the Delaware River Basin.

For example, Preparedness, Prevention and Contingency Plans (PPCs) are required by some host states to provide additional watershed protection; however, in practice, they do not adequately identify environmentally sensitive areas and do not include sufficient tactics and strategies to protect those areas. Furthermore, PA and NYS contingency plans do not require a well control plan, a written well control barrier policy, a well blowout response plan, or contracts with well control experts. The administration of PA and NYS contingency plans stands in sharp contrast to practices in other state and federal agencies, which do require response plans to deal with a worst-case blowout scenario.

DRBC should wait for the promulgation of new host state regulations before finalizing its own regulations, so that it knows what additional protections are needed for the Delaware River Watershed. Alternatively, DRBC's Proposed Regulations should be expanded to address known deficiencies in existing host state regulations.

Harvey recommends, and we agree, that the Draft Rules require Best Available Technology (BAT) and Best Management Practices (BMP), which the host states do not require, as discussed in these Comments under Section 7.1(e)(3). The Draft Rules do state that BMPs are required (although we do not agree that the Draft Rules indeed contain BMPs) but they do not state that BAT is required. (Harvey p. 22) We also agree with Harvey that cement integrity evaluation is lacking in host state regulations; the Draft Rules should require a Cement Evaluation Tool (CET) or Cement Bond Log (CBL) to verify cement integrity at the well bore. (Harvey p. 22)

Harvey recommends and we support that blowout control equipment be required to be in place on the well site and/or a minimum of two well control barriers with trained personnel to install and operate the equipment. (Harvey p. 23) A well blowout response plan with requirements for equipment and the

nearby availability of a rig to drill a relief well in a timely manner should be required in the Draft Rules, as recommended by Harvey, since on average 7 out of every 1,000 on shore exploration wells blowout. (Harvey p. 23) The blowout that occurred in Clearfield County went unabated for at least 18 hours because the blowout preventer either malfunctioned or was not in place and there were no trained personnel to control the well explosion. A team of trained personnel was flown in the next day from Texas. The geyser of fracturing fluid and water could have been stopped or prevented if this equipment has been used and personnel had been trained.¹⁷

Harvey states that the Commission must provide justification of its heavy reliance on host state well construction and operation regulations and that it has not done so. A detailed analysis showing how PA and NYS regulations protect the Delaware River Watershed is essential before the Commission can propose its regulations so that it is clear that gaps do not exist and the Commission's requirements for water resource protection can be met. Alternatively, the Commission should adopt its own regulations. (Harvey p. 15)

Similarly, the Commission assumes that host states will have sufficient resources to administer regulations but there is no evidence provided to support that assumption. Host states are already under tremendous strain and gas development in the Delaware River Watershed will compound that. There needs to be an analysis done to assure that management, inspections and enforcement of this new activity can be administered by the host states. An economic analysis of the state funding needed to cover these additional tasks by the host states should be prepared by the Commission and/or the host states. Alternatively, the Commission should consider expanding its regulations and staffing to provide this need. (Harvey p. 15)

Harvey highlights specifically the need for the Commission to require Preparedness, Prevention and Contingency (PPC) Plans. (Harvey p. 21) The spill plans should require the identification of environmentally sensitive areas that will need to be protected such as wetlands and threatened species habitat. (Harvey p. 23) PADEP requires a PPC that has several important components but she reports that in practice many of the plans did not include the required components.¹⁸ A spill of hydraulic fracturing fluid by Halliburton, a subcontractor to Cabot Co. in Dimock, PA, occurred on a gas well site where spill prevention plans were not in order; the PADEP remedy included a requirement for Cabot to bring its PPC plan into compliance to prevent future hazardous spills.¹⁹

The host states also do not require site-specific mitigation plans as a routine condition in permits. The Draft Rules should include this requirement to protect unique situations in the Watershed. (Harvey p. 24) All equipment and materials should be required to be checked regularly for corrosion and erosion to prevent spills and leaks. This is not required by host states but is a industry best management practice. (Harvey p. 24) Also, the Draft Rules should require the fracture treatments that are used for gas wells be modeled, designed, and monitored, and the data collected before during and after fracturing operations should be filed in reports filed with the Commission and made publicly available.

Of specific concern regarding well construction is inadequate grout sealing that can and has led to gas migration and methane pollution of groundwater in Dimock, PA and surface water in the Susquehanna River, PA. As is explained by Demicco (p. 3-4):

The specific concern is the high pressure of fracturing at depths with a thin grout seal surrounding the well casing. The requirements in the Pennsylvania regulations only provide a 1-inch grouted annulus above the top of the Marcellus Shale in a region where the well casing is not perpendicular. Centering the well casing in the borehole is one challenge. Assessing the quality of the grouting job is difficult at these depths. Detailed requirements for grout evaluation and test logging are not included in the regulations. Only several hundred feet of grout is required above the Marcellus Shale and the balance of the borehole is not grouted until the well reaches casings protecting the freshwater aquifers. A large section of the borehole is left ungrouted, which, in my opinion, is a highly questionable and inappropriate practice. Specifically, fugitive gas from ungrouted formations within the borehole can also migrate up to the shallow fresh water zones as described below in reference to methane gas being observed in the Susquehanna River.

Demicco explains how the lack of proper grouting can cause a large scale pollution release (p. 4):

However, looking at the problem simplistically, let's assume the grout above the Marcellus Shale failed or the open borehole encountered gas from a shallower zone and pressurized the entire annular space up to the base of the freshwater casings. The grouted casings at this shallow depth will probably not fail as the grout is not fractured like the adjoining bedrock. The shallow horizontal and vertical fractures that are exposed to deep formation pressures would probably open as the weight of overburden is significantly less at 1,000 feet compared to depths of over 1 mile. The existing rock fractures would open and allow gas migration away from the well, particularly in the direction of regional fractures (north-south). The rock failure would begin roughly 1,000 feet below grade. Horizontal bedding plane fractures would allow movement of gas at least 5 to maybe 10 times faster horizontally than vertically. This is based on the typical horizontal to vertical hydraulic conductivity ratio of 5:1 to 10:1 in bedded sedimentary rocks. Gas could potentially migrate 10,000 feet laterally while moving the 1,000 feet vertically. This distance of gas migration is consistent with the reported gas bubbles in the Susquehanna River reported at a distance of 3 miles from known gas wells. The potential impact area, a 10,000 foot radius, is roughly an 11 square mile area, similar to the area impacted at the Dimock site (see Attachments 2, 3 and 4).

The impact that a single well or small number of failed wells can have on water resources by itself is justification for increasing the stringency of drilling regulations, especially given the 15 million people dependent on drinking water resources of the Basin (see letter by PADEP Secretary John Hanger, Attachment 3).

Rubin provides ample evidence of the substandard well construction and plugging and abandonment regulations that are in place in the host states. Well casings, cementing, and cement plugs are not

regulated to protect aquifers and will lead to pollution, either in the short term or as they degrade. Because hydraulic fracturing opens joints well beyond the borehole, plugging and abandonment practices may do little to protect the environment after chemical additives are repeatedly injected into bedrock formations under high pressure. Also, presently used cement mixtures and other materials do not achieve zonal isolation in each well, allowing for escape and comingling of fresh and contaminated subsurface waters. Rubin concludes that the implications of short term cement failure on long term aquifer water quality protection are extremely significant and the Draft Rules do not “protect the water resources of the Delaware River Basin...to meet present and future needs” as expressed in Section 7.1 because of these inadequacies. (Rubin p. 3-4)

Rubin also points out that state of the art cement mixtures and sealants (i.e. self-healing mixtures such as FUTUR cement) are available that can react to and repair channels through which hydrocarbon-rich fluids and gas may otherwise migrate but host state regulation do not require these. In addition, well construction analyses and cement integrity monitoring are standard industry best practices that provide protection and can prevent contaminants from migrating but are not required by host states. (Rubin p. 5) Numerous cement, casing, and steel failure mechanisms are detailed in Rubin’s report, illustrating why current host state regulations will at some point lead to well integrity failure and water resource contamination. (Rubin p.8-26, Addendum 5 - Life of Concrete Material and Steel)

Rubin explains that host state regulations do not provide needed zonal isolation due to cement and steel degradation. This is important because of the connections that can be made to aquifers. Rubin explains (Rubin p. 10-29):

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 really 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 millennia. 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. Freshwater aquifer protection requires a well sealing technology that matches and restores the natural hydrologic integrity that exists before drilling commences. 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 supersede 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., H₂S and CO₂). 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 that 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 production 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 $\mu\text{m}/\text{yr}$ (20 to 40 $\mu\text{m}/100 \text{ yr}$). 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 decrease 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 - 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 after 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.

Trocónis de Rincón 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, CO₂ 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% CO₂ and/or > 100 ppm H₂S) 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 CO₂ 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 CO₂ leakage back to the surface via wellbores. Chemical research, field assessment, and experiments have shown that CO₂ 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 CO₂ leakage in a wellbore. Krilov et al. (2000) document cement deterioration caused by CO₂ 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 CO₂ and H₂S 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 very 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 CO₂ in deep geologic substrates to reduce the impacts of global warming has spurred a very serious look at our ability to effectively isolate and confine CO₂ 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 CO₂ injection, but millions of old oil and gas wells can serve as conduits for leakage of the CO₂*”. 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 CO₂ 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 CO₂-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 accentuated the evolution of cement chemistry and porosity with time, comparing Portland cement with a new CO₂ 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 CO₂-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 CO₂ is commonly associated with methane (CH₄), 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 H₂S 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. Yamini and Lence (2010) equate the probability of failure for a given exposure time as a surrogate for the service life of a pipe.

The key purpose of their analyses is to provide useful information to Towns in addressing the planning process for the rehabilitation and replacement 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 affect 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).

The Commission must regulate well construction since the host states do not have adequate regulations in place. The Commission should not allow approvals for gas well drilling until the technology has caught up and can protect aquifers. To risk the use of aquifers in the Basin is not acceptable. Rubin explains (Rubin p. 36-37):

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.

The Draft Rules also do not go far enough in the tracking of waters used. Tracking should include tracking the ultimate fate of the surface and groundwaters used in the drilling process, including documenting the underground and surface pathways and flows of these waters used in the drilling process to their final likely destination through pathways to the surface or underground. This “mapping” should be required to be reported to the Commission so that reliable mapping of created and existing fractures and pathways can be data-banked and made available for public use.

Section 7.2 Definitions

Brine – This definition is not specific enough; “appreciable amounts” needs to be explicitly defined.

Consumptive water use -- should be modified so as to specifically include water lost to underground as this is a significant and known end point for the vast majority of water used in the hydraulic fracturing process.

Critical habitat – should include species identified as candidate species or species at critical risk. Limiting the definition to species only specifically defined as endangered or threatened is much too limited.

Disturbed area -- The DRBC definition of disturbed area is “devoid of trees greater than 5 meters in height and substantially devoid of woody vegetation.” Under this definition, are areas of pasture, meadow or fields considered disturbed? Are only forested areas (greater than 3 acres) considered undisturbed? How are existing and built conditions taken into account for stormwater management and erosion control? Detailed stormwater calculations (for Pennsylvania well pads greater than 5 acres) show that the gas industry assumes that areas disturbed by well pad activity, but seeded in a seed mix that includes some brush species, are “better” than existing woods (and correspondingly generate less runoff). Under this definition for disturbed areas, it is unclear that there will be any change in this practice: disturbed well pad sites will still be represented as “better” than woods or pasture. (Adams p. 6)

Final site restoration -- should be modified to include the concept that if the site conditions prior to drilling were ones of disturbance that the operator will be responsible for, then returning that land to an ecologically sound and beneficial condition, with restoration to native woodlands being the primary objective, is required. There should only be an allowance of alternative conditions if there can be demonstrated a particular ecological need or benefit for returning to some other environmentally beneficial condition. In no instance should lawn and/or other impervious conditions be considered as fulfilling the final site restoration obligation. Defined as restoring a disturbed site “as nearly as practicable to its condition prior to the commencement of gas regulations”. Does this include restoration of topography, land cover, soil conditions, soil compaction, etc.? What parameters define restorations, and what mechanisms exist within the DRBC regulations or state requirements to achieve this restoration? (Adams p. 6)

Flood, regulatory -- should be rewritten to automatically mirror any changes in DRBC or federal law that may be adopted for defining the regulatory flood.

Forested Site -- this definition needs to be significantly modified. The definition of a forested site should not be dictated by the volume of trees removed, it should be defined by the size of the forested area that is going to be impacted – in other words, the definition is backwards. The definition should apply to any project that removes trees from any area with a tree canopy that is 3 acres or greater – i.e. if there is a stand of trees with a canopy that is 3 acres or greater then any removal of trees from within

that acreage should be considered to be taking place on a forested site. Defined as requiring removal of 3 acres or more of tree canopy. Does this refer to three acres of contiguous tree canopy, or three acres of cumulative tree canopy removal? Is this per pad site or based on holdings? If less than 3 acres is removed but is part of a larger contiguous tree canopy, is that considered forest? Is three acres the appropriate threshold? Are there any considerations for maintaining larger forest areas as intact (and reducing fragmentation) or are all areas considered equal? Is there any consideration for forest quality such as maturity and mix of species, vegetative community, or conditions of forest floor and soil mantle? Removal of forest increases stormwater runoff, increases erosion, diminishes forest soil quality and contributes to the decline of adjacent forest areas. (Adams p. 6-7)

High Volume Hydraulically Fractured Well -- is defined as a well that will be fractured with more than 80,000 gallons of frac fluid. However, DRBC does not provide any technical justification for its selection of an 80,000 gallon threshold. DRBC should provide this technical justification. DRBC should also provide a technical justification for its conclusion that environmental impacts to the Delaware River Watershed are automatically mitigated, without regulation, for frac jobs that use less than 80,000 gallons of frac fluid. (Harvey p. 31)

Horizontal Wellbore -- is defined by DRBC as a diagonally drilled or horizontally drilled wellbore. A diagonally drilled section of a wellbore (for example at 30 degrees) is not a horizontal well because that section of the well is only drilled at a 30 degree deviation from vertical and will not create a horizontal wellbore section. A horizontal wellbore is the section of a wellbore that is oriented 90 degrees to vertical. DRBC should use the term “high angle well” for wells that are not drilled on a true horizontal plane. (Harvey p. 31)

Impoundment – should not be limited to impoundments made of earthen materials – there are likely to be new manifestations of such facilities that include manmade materials and the regulations should not allow them to slip through a loophole.

Invasive species – is too limiting and sets too high a standard, mandating a demonstration of harm to the economic, the environment or human health on an individual basis is very limiting. There are many invasive species of plant and vine that have increasingly harmful affects over time, by virtue of their spread and proliferation over time. The definition should be limited to the elements of (1), subsection (2) in this definition should be deleted in its entirety.

Natural diversity inventory assessment – should not be able to be satisfied merely by a PNDI search. The PNDI database is not necessarily a complete inventory of all species and where they can be found, or should be able to be found. There should be a site specific assessment paid for by the driller and conducted by independent biological or other appropriate experts that is reviewed and approved by Commission biological staff (funded through the fees that should be assessed to the operator for undertaking this work) after being subject to public review and comment.

Natural gas development plan – should include not just present leaseholds but also future leaseholds, including future anticipated leaseholds no matter how remote the expectation of future ownership.

Natural gas development project – should include exploration projects. This is discussed at length in this Comment under Section 7.5

Pollutants -- are defined as a substance that degrades surface water or groundwater. This definition should include substances that impact the air, soils, crops, and human and wildlife food sources. (Harvey p. 31)

Post Hydraulic Fracturing Report -- is defined as a report provided after a frac job that lists the volumes and amounts of all chemicals and additives used during fracing. A pre hydraulic fracturing report should be submitted to DRBC prior to a frac job. A pre hydraulic fracturing report should list: each type of chemical that will be used, chemical composition, dosage rate, the amount planned for use, and information on harmful chemical-related impacts to human health and the environment. A pre hydraulic fracturing report should be reviewed and approved by DRBC prior to a frac job. A post hydraulic fracturing report should be used to compare actual chemical use with planned use. (Harvey p. 31)

Setback -- should specify the distance exploration and production activities must be setback from drinking water wells, endangered species, and critical habitat. (Harvey p. 32) Additionally, the definition describes only the distance between well pads and other features, not the separation distances between other infrastructure and features on the well development site (such the setback of a basin from a stream, a chemical storage tank from waterway, etc.)

Wetlands -- should mirror the federal wetlands definition. (Harvey p. 32)

Water Body -- while the definition for Water Body is comprehensive, the requirement for mapping at the scale of the 7.5 minute USGS topographical quadrangle (when mapping is required, which is limited) will result in numerous water bodies failing to be identified or adequately protected. Intermittent water features are not likely to be shown on a 7.5 minute quad, nor will ditches, small channels, or headwater springs and seeps. (Adams p. 7)

Well pad -- the definition does not accurately describe a well pad. It uses the singular to describe the well activity on a pad (as in “necessary to drill a natural gas exploratory or production well”). As many as 8 to 10 individual wells may be installed on a well pad (NYSDEC DSGEIS 2009); an even greater number may be installed because there is no limit imposed by the Draft Rule or the host state regulations on how many wells can be placed on one well pad. Also, there is no description of the size or limits of a well pad and the activities that occur on a well pad and the use of a well pad outside of one well are not

defined. It is implied that the well pad is a site or more than simply one defined location: "...a site constructed, prepared, leveled, or cleared in order to perform the activities and stage the equipment necessary..." Demicco asks: Does the proposed DRBC definition include the storage lagoons, piping, roads, and staging and parking areas? These facilities represent impervious cover, compacted soil areas, or excavations that drain shallow ground water, all of which reduce recharge to the deep bedrock aquifers. (Demicco p. 6) These areas also fit the Draft Rules' definition of a well pad. The definition should be reworded and made specific and descriptive so as to remove any ambiguity regarding regulation of the well pad.

Section 7.3 Administration

Section 7.3(a) Types of Natural Gas Development Projects. The Draft Rules appropriately address water withdrawals, Natural Gas Development Plans, well pads, and treatment or discharge of wastewater as projects that require individual review by the Commission. However, the caveat that is added stating "...unless the Executive Director approves otherwise" should be removed. First, all of the listed projects have the potential for substantial impact on the water resources of the Basin and meet the requirement for a reviewable project under the Commission's Rules of Practice and Procedure. Second, the circumstances in which the Executive Director might exercise her regulatory discretion to allow projects or elements of projects to escape Commission review are undefined.

Section 7.3(b) Types of Review and Approval and Section 7.3(c) Approval by Rule for Natural Gas Development Projects. The Draft Rules appropriately list dockets and protected area permits as types of approvals. However, we are opposed to the establishment of an Approval by Rule as a type of approval. The definition of Approval by Rule (ABR) is approvals to be "granted, denied, or conditioned by the Executive Director for projects that meet the requirements for an ABR in accordance with these regulations." The ABR process essentially allows for "self-regulation" by the operators without justification by the Commission for the lack of oversight and review that the Commission and other agencies apply to similar industrial projects. (Adams p. 2) We discuss the reasons that ABR should not be allowed under the specific subsequent sections that apply.

One fundamental reason for our opposition to the ABR process applies to all projects that are eligible in the Draft Rules for an ABR — namely, the decreased or eliminated opportunity for public review and comment on gas development projects.

If promulgated, the regulation establishing an ABR process will decrease and/or eliminate public involvement by, inter alia:

1. removing the ability for the public to participate in the permitting process;

2. removing the ability for the public to provide information in a timely manner to the Commission in its decision-making;
3. removing the opportunity for agency response to public input;
4. establishing a truncated timeline that fast tracks permitting at the expense of public involvement;
5. obscuring the actions of the Commission from the general public;
6. narrowing the way the public can give input to influence the Commission's decision such as no Public Hearing, no official public comment period, the lack of an iterative process in the Commission's decision-making on a project;
7. lowering the requirements for public notification, such as no posting of notification at the location of a site, lack of adequate broadcasting of projects to all affected parties such as those affected by the modification of a previously issued docket;
8. eliminating the opportunity for iterative decisionmaking with other agencies and government entities;
9. concentrating too much authority in the Executive Director; and
10. removing from the public ready access to records and files regarding projects approved by ABR which, under all current circumstances, is administered under the federal Freedom of Information Act by the Commission.

Section 7.3(d) Appeal. As the Exploratory Well hearing process reflects, the RPP is inadequate as a procedure for appeals for well projects. As there is no supersedeas provision, by the time a hearing is scheduled, the drilling companies will claim mootness. Further, members of the public who wish to protect their property rights and interests in clean water face the risk of economic ruin by assessment of hearing costs, creating a disincentive to the exercise of fundamental due process rights.

Section 7.3(e) Duration of an Approval. Ten years with the allowance of an extension for an additional ten years is an unreasonably long period of time for an approval of water withdrawals and natural gas development approvals. This is especially true for ABR approvals that can be issued and extended by the Executive Director alone. But it is also true for dockets and approvals that require Commission action.

The Commission has not set any upper limits of how much water, overall, can be allocated and consumed by natural gas development because there has been no cumulative impact analysis completed.

Natural gas development has not yet begun in the Delaware River Watershed so there is no information about how the practices used for gas extraction in the targeted formations will affect the environmental features of the Basin such as subsurface geology and groundwater, surface soils and water bodies, etc. Its impacts are not known and there has been no modeling or analysis of how the environment may respond and what limits should be placed to avoid adverse impacts.

The fact that the Commission or Executive Director can rescind a permit if adverse impacts become evident, assumes that adequate monitoring and oversight will reveal such impacts in a timely way (and the Commission and host states do not have regulations or propose to adopt regulations that would supply that assurance). Also, a ten- to twenty-year permit duration encourages an operator to invest in the build out of a project and will work against the cancellation or shortening or non-extension of an approval.

Exploratory well and low volume hydraulically fractured wells are allowed to proceed under host state regulations in terms of permit length. These types of wells can have equal, or in some instances, more impact than other natural gas projects and should not be given any lesser scrutiny or limits. See reports submitted in Consolidated Administrative Hearing, Attachment 2.

Permits should have a one-year to three-year duration, after a cumulative impact analysis, scientific studies and planning efforts and a public process has demonstrated that natural gas related activity should move forward in the Watershed without violating the legal requirements regarding water quality and quantity imposed by the Compact, Water Code, and RPP.

Also, a provision should be added that if regulations change in any jurisdiction, federal, state, county or municipality that relates to relevant aspects of the approved project, the project's approval is null and void. The building in of no opportunity for "grandparenting" of permits provides needed protection for the public and the environment to address improved regulation of activities and the improvement of technology and management practices that will reduce adverse impacts.

Section 7.3(f) Expiration. The expiration of an unexecuted approval on the third anniversary of the date of approval and the allowance of an extension by the Executive Director is too long. PADEP for instance requires a renewal application for a gas well drilling permit after one year if the approval has not been acted on. A renewal should be required to preclude "grandparenting" of outdated approvals and to allow for changed conditions to influence the consideration of a project by the Commission. It also provides important opportunity for other governmental entities, such as municipal government to influence and participate in decisions regarding projects within their jurisdiction.

Section 7.3(h) Docket, protected area permit and ABR modification or suspension by Director. The Executive Director should have the power to suspend approvals or require actions by an operator to address adverse impacts, especially considering that timely action by the Commission at a public

meeting is not possible. But in order to effectively oversee and act, the Commission will need to secure or provide an inspection and enforcement program that is capable of handling the full oversight of these activities. Otherwise, this provision gives a false sense of security to the public.

The Executive Director should not be able to approve modifications to a docket, protected area permit or ABR conditions unless it is for protection of the water resources of the Basin. Not only does it remove the modification from the rigors of the process that were applied originally to the approval, but it also removes these decisions completely from the public participation process and obscures these decisions by the Executive Director and Commission from public and other governmental reviews. This is unacceptable and should not be allowed.

Section 7.3(i) Public Notice Procedure. Notification of property owners within 2000 feet of a project is extremely limited and not sufficient. (Adams p. 9) Notification should be defined by those who could be affected by the project. For instance, neighboring water well owners who are within the zone of influence of a natural gas well project should be notified if their well could be affected based on the findings of the aquifer testing that should be done for each well project and water withdrawal, as discussed under those sections in the comment herein. Another example is the notification of a community that relies on drinking water supplies through a water withdrawal docket that is being modified to allow some of the water to be diverted from public water supply to natural gas development. Another example is a community whose water supply intake is located downstream of a gas drilling wastewater discharge or a community located downstream of a well pad that could generate nonpoint source pollution, runoff and increased flooding. (Adams p. 10)

Further, the measurement of where notification should occur should be based on the terminus of a horizontal well bore and possible fracturing related to hydraulically fractured wells. (Adams p. 10) The measurement should be measured from the outside limits of activity related to the gas development project, such as a storage pit, water basin, or construction staging area, particularly if any hazardous materials are to be handled, stored, or transported. Notification also brings up the issue of air emissions and odors. Of particular concern are emissions that could be hazardous to human health and the environment. An air flow analysis should be conducted to delineate the possible pathways for air flow should any dangerous air emissions or noxious odors be possible and notification of neighbors that could be affected by air flow from the activity should be notified.

The proposed notice requirement in “a newspaper of general circulation in the area” is not sufficient. Too often newspaper notification goes unseen due to the variability of what papers the local public reads and because today many people do not consult the newspaper as regularly as they used to. Posting in local places such as a municipal building and post office should also be required. Many members of the public rely on internet use to obtain information today. It is important that the Commission’s website post every notice of a project and that the municipality be required to post notice on its website. The Commission has long used an “interested Parties” notification by mail of projects within the areas of

concern for governmental and nongovernmental organizations and members of the public. This could be accomplished inexpensively by email notification and should be required.

Section 7.3(j) Site Access. The Commission should have access to projects without notice at all times. One of the difficulties in timely investigation and thorough inspections of projects by some governmental entities is the lack of access. This is very important for the prevention of pollution and timely response to a complaint or irregularity at the location. We do not agree that two hours notification is necessary for unstaffed facilities. Immediate access to unstaffed facilities should be required and it should not be assumed that staff cannot be at an operating project within that period of time. Any project that is operational, whether it is during usual work hours or not, can cause adverse impacts, accidents, hazardous conditions or pollution releases so should be open to inspection at all times even if an event is not reported or verified. This is a preventive measure that makes sense considering the dangerous nature of the materials and activities at natural gas operations.

It is important that records be kept at the site for inspection purposes but we object strongly to the proposal that records required for approval of certain projects will not be kept at the Commission's offices but only stored on site and only made available at the request of the Commission or Executive Director. Transparency in Commission operations is crucial and this policy blocks transparency. (Adams p. 5) It removes the ability of the public to view these records at the Commission and poses the question of how the public can gain access to these projects to access these records. No procedure for such public access is included in the Draft Rules. The result of recordkeeping at the project site is that the public is unable to access information on activities that may affect their water resources. (Adams p. 10) This is unacceptable; all records should be kept at the Commission offices also and available for public review through the FOIA process.

Section 7.3(k) Financial Assurance Requirements. The financial assurance requirements are entirely inadequate and must be revised upwards by substantial amounts. There are many deficiencies in this Section of the Draft Rules. Adams points out that ambiguities in this section will lead to loss of resources. Adams explains (p. 7-8):

Section 7.3(k)(1) discusses financial assurance "for **restoration of land disturbances**...." as required by Section 7.5(h)(1)(vi). However, Section 7.5(h)(1)(vi) simply states to restore land disturbances "according to host state requirements". Pennsylvania requirements are nominal (i.e., seeding with a seed mix that includes brush), with no mechanism for inspection or enforcement. New York has no specific requirements at the moment.

Section 7.3(k)(17)(ii) allows for release from Financial Assurance when restoration is complete, and states "successful restoration of well sites and access roads may only be considered complete after observations over two growing seasons indicate **no significant impact on hydrologic resources**". But what defines "significant hydrologic impact"? Is an increase in stormwater runoff volume with stream morphology changes "significant", and at what threshold is an increase "significant"? Who conducts the referenced

observations to determine this? Are the “observations” conducted by the project sponsor, and what constitutes observation? Are observations simply visual assessments by the project sponsor? Are observations sufficient to assure that baseflow conditions have been maintained, especially in headwaters and wetlands? Again, without metrics and performance standards, the definition of “significant impact on hydrologic resources” does not provide for industry regulation. If all observations and reporting are conducted by the project sponsor with undefined requirements and standards, compliance is self-monitored and subjective.

Equally importantly in regards to Financial Assurance, there is no mechanism to determine if the required amount of \$125,000 is sufficient to address “impacts” when what constitutes an impact is undefined. There are likely to be costs associated with technical observations and monitoring if these are in fact required, and such costs can quickly exceed \$125,000.

It is worrying to note that the draft regulations expend more detail describing how and when the \$125,000 financial assurance can be reduced (by 75%), than in defining what “no significant impact to hydrologic resources” means. The draft regulations provide a process for reducing the financial assurance by 75% when only one year has elapsed since hydraulic fracturing is completed (Section 7.3(k)(15)). Specifically, the financial assurance can be reduced if, after one year to the best of the project sponsor’s knowledge “no harm to water resources has occurred or been alleged”.

Demicco points out that the \$125,000 is woefully inadequate and makes recommendations, which we support (Demicco p.7):

The sum total of \$125,000 is woefully inadequate as shown by the current situation in Dimock, Pennsylvania (see PADEP Secretary Hanger letter – Attachment 3). A standard homeowner’s policy typically carries a \$1,000,000 umbrella liability coverage. Small businesses carry \$2,000,000 to \$5,000,000 in coverage. A simple oil spill with soil cleanup and ground-water monitoring will easily cost in excess of \$1,000,000. The water system alone for Dimock was estimated at \$30,000,000.

Section 7.3(k)(15) allows for the reduction of the financial assurance upon successful grouting and after the initial fracing if no further fracing is planned. However, grouting and casing shear can occur over time (add reference). Although additional fracing may be initially planned, a rapid decline in production may require addition fracing over the life of the well. A short time limit for substantial reduction of financial assurance is not practical in the gas industry.

Recommendation: A minimum of \$5,000,000 financial assurance per well and \$25,000,000 per well pad is recommended.

Harvey points out that the financial assurance of \$125K per well does not approach the human health and environmental impact costs that can occur and that private citizens typically carry more insurance on their family car. Yet, Harvey states, the risk profile for a family car is substantially lower than for a gas well in the Basin. (Harvey p. 28) Harvey continues:

DRBC has not provided a basis or justification for its proposed \$125K financial assurance amount. DRBC should complete a risk assessment of hydrocarbon exploration and development in the Delaware River Watershed. The risk assessment should include worst-case scenario impact models. The risk assessment should be used to set a higher financial assurance requirement.

Regarding the proposed reductions in the Draft Rules, we agree with Harvey's stated positions (Harvey p. 28-29):

DRBC's Proposed Regulations include opportunities to reduce or waive the financial assurance requirements. Section 7.3(k)(8) allows DRBC's Executive Director to reduce the financial assurance requirement by 25%. Section 7.3 (k)(15) allows a project sponsor to reduce the amount of financial assurance by 75%. There is no provision for DRBC's Executive Director to increase the financial assurance requirement to address project specific risks.

Section 7.3 (k)(15) allows a project sponsor to reduce the amount of financial assurance by 75% if DRBC's Executive Director determines that: a well has been drilled and successfully cased; fracing plans are complete; and one year has passed since drilling, completion of fracing operations and no harm to water resources is alleged. DRBC's Proposed Regulations do not provide review criteria for DRBC's Executive Director to determine that the stipulations for reducing the financial assurance amount have been met. Technical review and approval criteria must be set for DRBC's Executive Director to determine that a reduction in the financial assurance amount is appropriate, and that in doing so, environmental resources and public health are still protected to the maximum extent possible.

Section 7.3 (k)(17) of DRBC's Proposed Regulations provides a release from the financial assurance obligation two years after final restoration has been completed. This approach does not provide financial protection for long-term impacts, such as subsurface pollutant pathways (e.g. stray gas or subsurface chemical transport). Financial assurance releases should not be granted within two years of project termination, because subsurface pollutant transport may take many years.

There is no financial assurance requirement for oil wells in the Delaware River Basin. The financial assurance requirements in DRBC's Proposed Regulations at Section 7.3(k) are limited to gas wells. DRBC does not provide justification for imposing financial assurance requirements for natural gas wells, while not requiring financial assurance for liquid hydrocarbon exploration and development. Liquid hydrocarbon exploration and development can also pose significant risks to a watershed, including the risk of a well blowout or contamination from oil processing and transport.

7.3(k)(15): The mere one year time frame provided before the project sponsor can reduce the amount of their financial assurance is unreasonably short. The ramifications of gas drilling are significant and very likely to manifest themselves, individually and cumulatively, for years, as discussed at length below by Rubin. Allowing any reduction, but particularly such a large reduction as 75%, in just one year lays communities even more at the mercy of the drillers with little recourse should harm

manifest. Financial assurance is a reasonable expectation and cost of doing business in such a dangerous industry as gas drilling. There is no rational justification for such a minimal time frame before reductions in financial assurances are allowed.

7.3(k)(16)(i): It must be clear that the financial obligation is for each borehole, not just each well pad. The definition section does not provide this clarity, but it is essential that the text of the regulations does. The harms of groundwater contamination, increased seismic responses, and others discussed in this comment are the result of the boreholes and the hydraulic fracturing associated with them, and therefore it is the borehole that should trigger the financial assurance obligations.

7.3(k)(16)(vii): Again, use of a financial assurance instrument is not strong enough, actual money put forth up front is needed and warranted, otherwise there is too great a risk of the public shouldering the liability of addressing community and environmental harms in the future.

7.3(k)(16)(ix): Project sponsors should not be able to extend the life of their wells beyond that initially planned for, approved, or for which financial assistance was provided. The Commission and others made irrevocable decisions based upon the understanding regarding the planned life of individual and multiple wells; to extend the life of wells beyond those original representations undermines and renders inappropriate all decisions that came thereafter (i.e. were based upon the representations regarding the life and life cycle of the approved wells that came before).

7.3(k)(17)(i): Cement failure, chemical and gas migration are much longer lived than the active use of the well. Therefore, allowing release from financial assurances simply because above ground site restoration has taken place is not appropriate, and raises too much risk of future environmental and community harm that becomes the burden of future communities and taxpayers. The financial assurance obligation must continue for 100 years after the above ground restoration commitment and only be granted upon presentation of a comprehensive analysis documenting that there has been no underground migration of contaminants or increased seismic activity that has increased the risk of such migration.

Rubin points out the tension between operator costs versus the expenses of environmental and safety safeguards and the need for the Commission to require and enforce through financial assurances that decisions must be made to protect the water resources. Rubin elaborates regarding aquifer loss:

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.

Section 7.3(l) Project Review Fees. The Draft Rules must increase the fees substantially. The fee of \$2,000 is grossly inadequate to cover the coordination and additional protective monitoring that will be needed to be conducted and or overseen and maintained by the Commission. The operators need to provide and bear the cost of the monitoring equipment and staff resources that will be needed for regional studies, monitoring (air and water), and sonde networks as well as for their specific monitoring requirements required in the regulations. Duration of monitoring for decades will be required so fees need to reflect the enormous risk being undertaken. These costs should not be borne by the public agencies that are already under-funded or left to the public taxpayer through lack of effective clean up or restitution when there is a problem.

We support fees charged being nonrefundable and having to cover 100% of Commission's actual costs. These are costs incurred for the benefit of the project sponsor, regardless of the outcome of the review process and therefore should be fully and permanently borne by the project sponsor regardless of the process and outcome. The Draft Rules should be changed to reflect this.

7.3: ABR has no valid place anywhere in these regulations. The gas drilling process is too dangerous, too damaging, too new, too changing, and too massive to warrant any shortcuts in review, consideration or process, including public knowledge, inclusion and participation.

7.3(I)(9): There is no place for a fee waiver in these regulations. The Commission will incur costs in all of its reviews and oversight efforts, including requests for approvals of additional well pads. Those costs should be borne only by the project sponsors; any other outcome makes these costs the ultimate responsibility of the taxpayers.

7.3(I)(10): The annual compliance and monitoring fee must clearly apply to each and every borehole, not well pad. Further the 1% interest charge is way too low. Credit cards charge upwards of 13%, creditors of all sorts use much higher percentage rates for late payment of bills, and so too should the DRBC should charge a higher rate for late payment, both to encourage prompt payment by drillers and

to ensure full coverage of the costs associated with having to monitor and respond to late payments.

Section 7.3 (m) Reporting Violations. There should be no delay in reporting violations of the rules -- this section allows for reporting within 48 hours "or" when the sponsor becomes aware of the violation or circumstance. There should be no "or"; reporting must be immediate in every instance, with additional written reporting within 12, 24, 26 and 48 hours, and so on every 12 hours until the matter is in hand, and weekly until the matter is fully resolved. To allow the driller to find out a harm and then wait 48 hours before reporting is unjustifiable.

It is appropriate for violations or conditions that may lead to significant harm be reported immediately by telephone. But much more should be done. First, there should be an early warning system set up by the Commission so that all potentially affected water suppliers are notified of any spill or accident that could affect water resources or health. The Commission already is part of and helps to operate such a system in part of the Delaware River Watershed and automatic notification is made as per an emergency management protocol. This should be in place prior to the commencement of natural gas development in the Basin.

Second, the municipality and local emergency management and first responders should be required to be notified immediately when the Commission is notified in order to provide rapid response and containment. The public should also be notified using an automatic notification system such as is used in a reverse 911 system that uses phone and internet on-line connections to notify neighbors. With this instant notification, neighbors would be able to modify their use of water immediately if necessary. This on-line system and/or phone notification system should be included in the monitoring fees paid by the operators.

Third, there is no definition of what constitutes "significant harm to water resources." Therefore, there should not be any instance where a 48 hour lag time is allowed. And already there are problems with quick response from firefighters at gas well fires, as reported in Bradford County this year; traffic congestion from gas development related traffic is already slowing down and compounding response from fire fighters to incidents.²⁰

Fourth, there needs to be training provided regarding the unique impacts associated with gas well activities for all Commission personnel, volunteer responders, and others. There are many incidents reported where the emergency response team, even PADEP and PA Fish and Boat Commission personnel, did not know how to respond or how to protect themselves because the chemicals involved were not properly or quickly identified at the site. This has led to pollution incidents that were not handled appropriately and to the prolonging and neglect of certain conditions that could have been mitigated or stopped if training and information were at hand at the moment of the incident. One example is the blowout of a natural gas well in Clearfield County that caused pollution that continued

for many hours, releasing dangerous contaminants into the air and water.²¹ Another incident occurred at Stevens Creek in Dimock PA and resulted in environmental damage and possible human health impacts that could have been avoided or better controlled if the hydraulic fracturing fluids that were spilled by Halliburton were fully disclosed.²²

Finally, we agree that a written report should be filed fully disclosing the details of the incident but it should be made clear that this information is public. The Commission should require such a report to be posted on the Commission website as well as the municipal or other local website where the incident occurred so the information is readily available to the potentially affected public. While an investigation may take some time, 30 days is too long especially if there were any possible human health or environmental impacts that should be disclosed. Public health and environmental integrity is not given the attention it should in areas where gas drilling is proceeding.

It is important not only that records are kept but that the Commission take responsibility to compile records of incidents of pollution releases and complaints so that the data can be used to analyze impacts to protect human health and the environment before degradation is critical. Very little is known about natural gas development impacts on human health, for instance. The result has been a lack of data that could inform public health officials and protect the public. In Texas, for example, only when conditions reach such a critical level that they cannot be ignored has there been attention to air emissions and other pollution. A recent study shows air emissions from gas development has affected air quality and needs remediation but this was not addressed until levels became alarming.²³ Due to lack of tracking, human health impacts ran ahead of medical personnel in Colorado, where the first human health study is underway.²⁴

We oppose leaving to the Executive Director the decision about whether a complaint constitutes a significant effect on ground and surface water and must be further investigated by the project sponsor. The Commission should adopt a protocol and specific definitions. There should be a Board or Review Panel composed of technical and health specialists, public officials and the public that is established to review these issues on a case by case basis. The response protocol should be developed by the review board. Many of the responses in this section are appropriate such as written notification of potentially affected public and the requirement for repair, replacement, mitigation and restitution by the responsible party. Also we support the preparation of a restitution plan by a qualified professional as quickly as is reasonable. But again the public should be involved in the process as it develops so the process should not be handled by the Executive Director out of public view and with no public input.

Adams poses several questions regarding this section (Adams p. 8):

- What is meant by “significantly affects or interferes”? This is not defined.

- What are the parameters and thresholds that determine interference, and at what point is interference considered “significant”? Does this refer to water quality, and what parameters in groundwater or surface water? Does this refer to a reduction in groundwater well yields or stream base flow? How will changes be measured and monitored? Is an increase in runoff volume and downstream flooding considered interference with designated uses? Special protection waters should not be diminished in any way. Is a certain level of diminishment acceptable before it is considered interference?
- What process exists to notify property owners in the event of a reporting incident?
- The DRBC regulations do not outline a timeframe that the sponsors must abide by.
- Are there no reporting requirements for increases that are not large enough to “significantly interfere” with uses?

The result of such ambiguities and lack of performance standards is that the draft regulations create the appearance of requirements for restoration and reporting violations, without actually defining, imposing or enforcing restoration or meaningful reporting. Without defined metrics for performance and a process for monitoring and verifying compliance, such draft regulations are meaningless and create an impression of regulation where none exists. At a minimum, defined criteria must be established for:

- Restoration and what parameters adequately represent restoration.
- What constitutes “significant impacts on hydrologic resources,” and what are the project sponsor’s responsibilities and liabilities when significant impacts occur.
- What constitutes an “observation”, and an associated schedule and reporting requirements for observations.

Further, to only require that users of groundwater or surface waters affected by drilling will receive repair, replacement or mitigation if they are "substantially adversely affected, rendered dry or otherwise diminished" again sets too high a standard for response and action. While "otherwise diminished" may seem to some to be a good catchall, when it is paired with the significant hurdles of "substantially adversely" and "rendered dry" it suggests a high hurdle of impact before response from the driller will be mandated by even this catchall phrase.

In addition, with regards to quantity impacts, to be looking for an impact of "rendered dry" before action is required is way too high a standard forcing users of that water to experience tremendous hardship on the pathway to dryness before they are entitled to relief. Mere diminishment of the volume of water to any measurable degree should mandate response.

The Draft Rules should make operators responsible for contaminating aquifers by requiring that any and all contamination be cleaned up and the aquifer restored to its original condition. Rubin explains why this is crucial (Rubin p. 29-32):

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 not 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. 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. 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.

The Draft Rules should require complete restoration and/or replacement of aquifers, especially since the natural resource damage done by gas well contaminants entering an aquifer renders the aquifer useless for the entire geographic region it serves as well as the individuals who lose their well water. The damage is virtually irreparable and the impact is a loss of the total natural resource for the foreseeable future.

Section 7.3(n) Enforcement. First, the Executive Director should not solely be in charge of this process. These decisions should be made by the Commission and/or a Review Panel or Board with, technical and scientific expertise, public presence and local involvement. We agree that the Commission should have the power to order an operator to cease and desist and correct the problem. However, as outlined above, without specific metrics about what constitutes an impairment and what constitutes a repair this Section lacks meaning. Second, we agree that the Commission has the power to suspend, modify, or terminate an approval due to serious or repeat violations. Again, there is no qualitative discussion of “serious” or other descriptors used. And the Commission has not proposed an enforcement arm and has not assured that the host states or the Commission will be able to oversee, inspect and enforce the natural gas projects it plans to approve. Also, the Commission should plan to coordinate with other existing enforcement agencies such as the EPA’s Criminal Investigation Unit.

Without the needed assurances that an enforcement arm will be in place prior to gas development, pollution and degradation will occur. The record of violations on the PADEP website²⁵ make it clear that violations and pollution incidents are occurring at a rapid pace in PA and, as stated elsewhere in this Comment, additional activity in the Delaware River Basin will strain further the limited resources of host states. For instance, budget cutbacks to PADEP have topped 30% over the last 2 years while permitting for gas well drilling is running ahead. In 2010 alone over 6,000 gas and oil drilling permits were issued by PADEP and 2,755 wells were drilled in the same time period. 2,486 violation notices were issued by PADEP for oil and gas activities in 2010. In March PADEP established a new policy regarding the issuance of violations by enforcement personnel that will further compromise enforcement actions by the state agency. A newspaper report quoted a directive that was issued by Deputy Secretary John Hines that notices of violation and permitting will require clearance from PA’s Secretary of Environmental Protection Michael Krancer; this policy could translate into less enforcement of the law, obviating the need for more Commission involvement. From the email published in the Patriot News it appears this policy directly applies to shale gas drilling as the subject line was “Marcellus Shale Action Approval Needed”.²⁶ Further discussion of enforcement is included in this Comment under Section 7.6.

As far as penalties, the penalty needs to be large enough to deter violations and sloppy practices that lead to accidents. Section 14.17 of the Compact states “...a penalty of not less than \$50 nor more than \$1,000 for each offense...” This amount is ridiculously low. It is much less a strain for an operator to

commit a violation and pay the fine than to invest in compliance. A complete overhaul of the penalty Section in the Compact or a new penalty Section should be adopted as part of the Draft Rules.

7.3(n)(1)(i): Again, the standard being presented is too high. Rather than having to show that a practice, operation or activity violates regulations or approvals or "poses a threat" before the Executive Director can take action to cease or mitigate or remediate there should simply be a possibility of harm and/or credible claim of affect and the Executive Director should be able to immediately act to cease the operation and take the appropriate action to identify the need for responsive action and order it.

7.3(n)(2)(i): "terminate an approval" should read "terminate any approval" to make clear that any approval can be acted upon.

7.3(n)(2)(ii): This provision should make clear that all costs associated with the issuing of notification as well as the appeal process are to be borne by the project sponsor. The provision should also be changed to ensure that any order to suspend, modify or terminate approval takes immediate effect, and does not await the outcome of a legal process that project sponsors will have every incentive to draw out as long as possible in the hopes that they can finish their drilling project before the final adjudication/decisionmaking can take effect.

If a suspension or termination is issued the project sponsor should be required to suspend/terminate all activities immediately until completion of the appeals process. If a notice of modification is issued, the driller can either comply or suspend their activities until the appeals process has been completed. In no instance must a driller be allowed to continue their activities once the notification has been issued – to do so provides the incentive to appeal in the hopes that no matter what the outcome the timing is such that the drilling is complete and the notification is rendered moot; and it also creates a presumption that our regulatory agencies are acting inappropriately in their enforcement activities.

The Draft Rules do not contain sufficient requirements regarding plugging and abandoning a well when production is completed and the approval is terminated. Rubin discusses the liabilities that need to be addressed as wells are closed (Rubin p.45-49):

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.

Section 7.4 Water Sources for Uses Related to Natural Gas Well Development

The Draft Rules do not protect the water resources of the Basin from depletion and diminution of water quality. First, there are scientific analyses and planning efforts that have not been accomplished; their omission is glaring. The Commission included in its Water Resources Program FY 2010-2015 “perform Cumulative Impact Analysis on water supply 2011-2012 Funding permitting” (DRBC 2010b, p. 17) but has not undertaken that study. The lack of impact analysis undermines the Commission’s ability to implement effective and sufficiently protective regulations. (Daniels, p. 6) Also, the Commission’s Water Code, adopted into the Commission’s Comprehensive Plan, states a policy to reduce water use (Water Code Section 2.1 Conservation, Resolution 76-17). The Code also states that underground water shall be preserved and protected and the frequency of drought requires that it be considered in water use decisions. The allowance of and weak governance in the Draft Rules of water withdrawals for natural gas extraction is contrary to these policies and purposes.

Daniels explains (Daniels p. 7):

Section 2.1 Conservation of the Water Code, which is part of the Comprehensive Plan, states a policy to reduce water use (*Resolution No. 76-17*). Specifically, “The Commission will undertake a long-range continuing program to reduce water use throughout the basin for the purposes of:

- A. Reducing the likelihood of severe low stream flows that can adversely affect fish and wildlife resources and recreational enjoyment.
- B. Assisting in the maintenance of good water quality by provision of minimum dilution flows and repulsion of salinity.
- C. Deferring the need for construction of new storage reservoirs and other water supply structures” (DRBC 2001, p. 2).

The use of water for thousands of anticipated natural gas wells will not help reduce water use in the Delaware River Basin and will not support achieving these stated purposes.

In addition, Section 2.20.2 on the preservation of underground water (*Resolution No. 64-11*) states, “The underground water-bearing formations of the Basin, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected” (DRBC 2001, p. 45).

Also, Section 2.30.2 (Resolution No. 91-9) points out that “[t]he waters of the Delaware River Basin are limited in quantity and the Basin is frequently subject to drought warnings and drought declarations due to limited water supply storage and streamflow during dry periods” (DRBC 2001, p. 49). The occurrence of drought should be considered in assessing the potential cumulative impacts of thousands of natural gas wells on water supply.

The use of water for the natural gas extraction process appears contrary to the conservation policy to reduce water use throughout the basin and the preservation of underground water.

We agree that any water use must be approved by the Commission and cannot proceed without Commission approval. The watershed-based management that the Commission has the authority to enact is essential to protect the water resources of the Basin, both in terms of quantity and quality. The host states of PA and NY do not have regulations that can accomplish this.

Section 7.4(a) Types of water sources.

Sections 7.4(a)(1), (2), (3), (5) Previously approved sources, new withdrawals, new withdrawals of treated wastewater and non-contact cooling water, mine drainage water (MDW). We oppose the use of surface and groundwater, treated wastewater, and discharges of non-contact cooling water unless the Commission provides water quality standards for their use that will not degrade the quality of the groundwater that could be exposed to the water that is injected into the gas well bore. It is DRN's position that the Commission must require project operators to meet the requirements of the Safe Drinking Water Act and follow the provisions imposed by the Underground Injection Program that is administered by EPA. It is our position that the Commission has the authority to impose these requirements and must do so to protect the water resources of the Basin and the water supply for over 15 million people.

Section 7.4(a)(4) Imported water. The definition of "imported water" in the Draft Regulations is different than the definition in the Water Code, §2.30.1 (Resolution 91-9). The Draft Regulations should be modified to incorporate the existing definition from the Water Code.

Section 7.4(a)(6) Recovered flowback and production water. We oppose the use of natural gas drilling wastewater, flowback or production water for natural gas development purposes. Based on our Comments under Section 7.5 and the expert reports herein, we cannot support the reuse of these highly contaminated waters. Our opposition is based on evidence of the toxicity of these waters and the lack of justification for any storage, handling, exposure or transport of these fluids outside of immediate removal to an approved wastewater processing facility. Since under the Clean Water Act, gas drilling wastewater must be processed at an approved facility that treats the waste to specified standards, it does not stand to reason that this wastewater could escape this requirement when it is reused at a gas well project rather than transported to a treatment facility.

The constituents of produced water vary depending on the geologic conditions, the composition of the gas, and the chemical properties of any injected fluids, such as fracking fluids; produced water requires treatment before discharge under Clean Water Act requirements. During natural gas production, produced water is separated from the gas. The Department of Energy has found that this wastewater product has "higher contents of low molecular-weight aromatic hydrocarbons such as benzene, toluene,

ethylbenzene and xylene (BTEX) than those from oil operations; hence they are relatively more toxic than produced waters from oil production.” The fluid also may contain salts (chlorides can be so high that the liquid, called “brine”, is 5-10 times saltier than sea water), high iron and barium levels, and may be acidic (typical range is 3.5-5.5). It is estimated that the produced waters discharged by natural gas operations are about 10 times more toxic than those from offshore oil wells.²⁷ US Geologic Survey also reports that natural gas condensates may also contain the chemicals known as “BTEX”.²⁸

NYS has published a list of constituents in gas drilling Marcellus shale wastewater from Pennsylvania and West Virginia; many are hazardous.²⁹ The track record of the industry in terms of spills, well bore failures, and other pollution incidents – as discussed in these Comments -- makes it impossible for us to consider adding the handling and reuse of this waste material to the risks already posed by activities at natural gas project sites.

Finally, there may be constituents in flowback and produced waters from gas development that are not regulated under the Safe Drinking Water Act even though they have human health risks and ecosystem/environmental impacts. Some substances are chemicals that are unregulated and for which there is no maximum contaminant level (MCL) yet set by EPA for drinking water quality³⁰. These pose additional unacceptable risks because they may be released into the environment without detection or any requirement for treatment. Some of these are endocrine disruptors or pharmaceuticals that may occur in gas drilling wastewater.³¹

Section 7.4(b) Preliminary determinations.

Section 7.4(b)(1) Substantial effect. This section provides some description information about the effects of drilling and the size of its impact, but by giving misinformation, and leaving out obviously critical information, it provides a skewed and inaccurate picture and therefore provides a less than effective basis for the regulations and their requirements. These inaccuracies and deficiencies need to be remedied.

This section needs to acknowledge that it is not just thousands of gas development projects that are expected, it is tens of thousands. Harvey discusses a range of numbers (Harvey p. 17):

DRBC’s own experts explain the potential for large scale impacts to the Delaware River Watershed:

“The Marcellus Shale formation in northeastern Pennsylvania and southern New York underlies about 5,000 square miles or one-third of the 13,500 square-mile Delaware River Basin.” . . . “Over 15 million people (approximately five percent of the nation's population) rely on the waters of the Delaware Basin for drinking, agricultural, energy and industrial use, but the watershed drains only four-tenths of one percent of the total continental U.S. land area. The 5,000 square-mile area common to the Marcellus Shale and the Delaware River Basin includes a 73.4-mile stretch of the Upper Delaware Scenic and Recreational River, which snakes gracefully through the rural countryside of green rolling hills (Figure 2). Within this same area, the Marcellus Shale includes some of the most promising sections in terms of the thickness of organic-rich shale.”³²

It is estimated that a total of 16,000-64,000 wells could be drilled in the Delaware River Basin. This estimate was developed using the planning assumption put forth by DRBC's expert O'Dell³³

This section should also specifically mention the removal of forested landscapes, and the transformation of a forested Upper Delaware landscape to an industrially developed landscape. And this section should specifically mention the introduction of toxic, highly salted and radioactive pollutants into the environment and human community, both those added by the drillers and those extracted from the ground during the drilling process.

Further, the range given for the volume of water needed for the hydrofracking process is clearly under-representative. The regulations discuss a range of 3 to 5 million gallons for fracking a well, and yet the DRBC has made clear that 5 million gallons is not the upper range volume that is needed to frack a well but is merely the average with the upper range being 9 million gallons or higher. The range needs to be corrected so it is accurate.

We agree that the uses listed may have a substantial effect, either individually or cumulatively, on the surface and groundwater resources of the basin. These Comments and the expert reports herein document the substantial effects of these activities.

Section 7.4(b)(2) Rules of Practice and Procedure (RPP) thresholds not applicable. We agree that the thresholds established by the RPP for the review of projects under Section 3.8 of the Delaware River Basin Compact do not adequately protect the water resources of the basin from the effects of natural gas development. The Commission must review and approve all sources of water for gas development because of the depletive nature of this use. We agree with the conclusion that the quantities of water needed for gas well extraction and development, the consumptive nature of its use and the total loss to the hydrologic cycle of this water means that the stream and river flows and assimilative capacities in these ground and surface waters will be reduced.

Unfortunately, the Commission has not proposed any limits or means of measuring and/or assessing the impacts of these depletive withdrawals. There is no cumulative impact analysis if water losses and this missing link in the Commission's management of water resources is not filled by simply removing thresholds.

By way of example, the Stone Energy water withdrawal approval granted by the Commission allows up to .70 million gallons of water per day to be removed from the West Branch of the Lackawaxen River. The river is a low flow river with high quality and wide diversity of benthic life and naturally reproducing populations of brown trout, brook trout, and rainbow trout. The National Park Service issued a report summary in February 2010 of testing it conducted on Upper Delaware tributaries that

showed of all of the twelve rivers sampled in the Upper Delaware Scenic and Recreational River, the Lackawaxen River had the most taxa of all the streams (35 taxa) with the exception of the Mongaup (38 taxa) and it tied with Equinunk Creek (35 taxa).³⁴ The high quality and ecological diversity of this river is jeopardized by the withdrawal and yet the approval was still given by the Commission without any consideration of the potential for degradation of its water quality, aquatic life habitat, and ecological health. This is just the first water withdrawal application to be approved by the Commission and represents only one operator, Stone Energy, and yet the impacts of this withdrawal will be substantial.³⁵

Section 7.4(c) Conditions.

Section 7.4(c)(1) Water sources for natural gas projects. We agree the Commission's approval is mandatory for water for all natural gas development projects. Harvey recommends that operators submit Water Management Plans for Commission review and approval. PADEP has inconsistently required Water Management Plans for the exploration wells that have already been drilled in the Delaware River Basin so PADEP cannot be relied upon to require these Plans. (Harvey, p. 20) New York has no requirements for Water Management Plans.

Section 7.4(c)(2) Importations and exportation of water and wastewater for natural gas development. We oppose the use of Approval by Rule (ABR) for any natural gas project, including the exportation of nondomestic wastewater from natural gas development projects from the Basin which the Draft Rules allow to be approved by an ABR. The implication is that there is a lesser impact on water resources from the exportation of wastewater than from other natural gas water uses. The exportation of wastewater removes the percentage of recovered wastewater (flowback or produced water) from the Watershed. This is an out of basin transfer and should be subject to the provisions of the Water Code Article 6, Section 2.30. Impacts associated with the depletion of the Watershed's water flows and the water quality impacts discussed in this Comment and in the expert reports herein illustrate that the Commission is not providing protection of the Basin's water resources through the Draft Rules.

Section 7.4(c)(3) Alternate review and approval process for sources previously approved by the Commission. We oppose the use of ABR for already approved water sources. Demicco explains that this constitutes a change of use from the original need that was justified for the withdrawal. He recommends that an ABR not be used to change the condition of use for a previously approved allocation and should be subject to thorough technical review and public hearing. (Demicco p. 10)

Demicco states (page 9-10):

Existing water allocation permits were approved based on justification of water supply needs as well as the ability of the water source to produce the water without negative environmental impacts. Using previously approved sources of water for gas exploration represents a change of use for a variety of affected populations without public hearing and should not be allowed. The volume of available water between actual use and permitted use should not be particularly large if the original application justification of

water need was accurate. In addition, gas exploration water use is 100 percent consumptive and the original permit may not represent 100 percent consumptive use.

This is particularly true for drinking water allocations. Drinking water supplies usually return up to 80-90 percent of the water either through septic system recharge or discharge through a treatment plant. Section 7.4(d)(1)(vi) allows ABR if the applicant demonstrates that no adverse affects will occur. Public comment on potential adverse impacts should be presented in a public meeting setting that provides the opportunity for public input into the decision making process. The use of existing water allocation permits (essentially a reallocation of the use of the waters controlled by those permits) for gas drilling, should not be approved as an ABR due to the complex nature of water resource impacts and the broad range of populations and water uses that could be affected. I do not know of any state water use regulation where the potential use of a resource is changed without major permit modifications including advertisement for public hearing and including a public participation process. The DRBC should be at least as restrictive as state requirements.

In addition, the proposed use of waste water under the ABR also should not be used as again a potentially non-consumptive discharge of water is becoming a 100 percent consumptive use, without public hearing. Again, the proposed regulations allow ABR if the applicant demonstrates that no adverse affects will occur. The complexity of potential impacts and the broad range of potentially affected populations should be presented in a public meeting setting with the opportunity for public input into the decision making process with the views of multiple affected parties presented, and not be approved as an ABR.

Section 7.4(c)(3) allows for ABR for new water sources within a Natural Gas Development Plan (NGDP). The NGDP does require evaluation of impacts from surface water and ground water withdrawal. However, ABR is also allowed for these water sources as part of the NGDP. Any new water withdrawal project should require a Docket and public hearing as per 7.4(c)(4), giving the public an opportunity to review the data and applicant's reports and providing the opportunity for public input into the decision making process. This is typical of the allocation process in states where a public hearing is a key component of the approved water use.

Section 7.4(c)(4) Normal review process. Water withdrawals should each require an individual review under the Commission's docket permitting system after cumulative impact analyses and scientific studies have determined how to proceed while protecting the water resources of the basin from pollution and degradation.

Section 7.4(d) Approval by Rule of previously approved sources to supply water for natural gas development.

Section 7.4(d)(1) Approved withdrawals. We oppose the approval of water withdrawals by ABR as discussed under (c) above. Additionally, nonpoint source pollution controls (Nonpoint Source Pollution Control Plans) required under the Water Code for water withdrawals are not required for ABR

approvals, which will result in nonpoint source pollution, erosion and sedimentation, and damaging stormwater runoff to the surface waters of the basin, in violation of Water Code Article 3.10.3.A.2.e. Adams explains that in PA, for instance, inadequate regulation of stormwater will lead to nonpoint source pollution (Adams p. 13-14):

As described in detail in Attachment 1, approval by Pennsylvania does not assure that erosion & sediment control or stormwater management are adequately addressed for resource protection. Pennsylvania only requires that stormwater be addressed for sites over 5 acres, and further waives the submission of any plans or stormwater calculations if the applicant indicates that, 1) original contours will be maintained or replicated, and 2) stormwater BMPs are employed to address the 2-year volume increase. Pennsylvania's requirements are not adequate to protect Special Protection Waters or other waters.

Also, we do not agree that already approved sources should be used for gas drilling but that these should be considered under an individual docket as a new source of water. Under Draft Rule Section 7.4(e) there are additional technical review requirements that should apply to all water withdrawals since the depletive and consumptive nature of the water use by gas development substantially changes the potential for impact.

Adams proposes several questions and submits comments about this approval process that details our reasons for our opposition (Adams p. 10-13):

- The draft regulations allow for an increase in individual well allocation (but not total allocation) if it will not adversely affect other wells or surface flows. But how will this be determined? The draft regulations do not impose additional requirements for a hydrogeologic report, so can it be assumed that such a report already exists for individual wells, and that this data will be referenced in determining the allowable increase from an individual well? Will data be reviewed by the DRBC? Will data be available for public access? Who determines what the allowable increase from an individual well should be?
- The draft regulations recognize that natural gas water use is one hundred percent consumptive, and the regulations require that this consumptive use not adversely affect streamflow at a withdrawal location, or from a location where wastewater is normally discharged. But again, how is this determined, and how will the determination be reviewed by the DRBC? At what location does the Q7-10 and pass by flow requirements apply? Does it apply to wetlands, intermittent streams, and other headwaters, especially if an individual well withdrawal is increased? Who determines the Q7-10 and pass by flow requirements for these water bodies – is the value calculated by the applicant and reviewed by the DRBC? How is it considered in the increased withdrawal from an individual well? This requirement has no meaning if parameters are not defined.
- The consumptive use of water for hydraulic fracturing is, in large part, qualitatively different than “conventional” consumptive use. It is estimated by agencies and the

industry that on average about 15% of the fluids injected into the well bore to hydraulically fracture a shale well is returned to the surface. The approximate 85% left in the ground is not only consumed but is lost to the hydrologic cycle, much of it forever sequestered in deep formations and intermingled with resident marine waters. This complete removal of fresh water from natural hydrologic processes represents an additional impact because this water will not be naturally recycled back into our environment, compounding the environmental effects of this fresh water depletion both in the Watershed and to the larger environment. How will DRBC evaluate this added impact for water sources, both in the APR process and for new water withdrawals that require docket approvals?

- In the permitting of approved water sources, did the DRBC previously make the assumption that a portion of the water use would be consumptive, and if so, does this assumption represent the anticipated needs for natural gas facilities? If not, how will the cumulative impacts of multiple natural gas facilities and their consumptive water needs be fully addressed, even if the water sources are previously approved? In other words, have the full watershed impacts of consumptive use been considered for previous existing approvals?
- The draft regulations indicate that withdrawals must be metered (continuous recording), transferred directly to trucks, and records held at the site. Quarterly reports, including the amount of withdrawal and destination, must be given to the Commission at request of the Commission. Is there a process for public access to this information? Does the Commission have a plan to collect and evaluate the withdrawals and their destinations? Will this information be available quickly in the event of a pollution event or water emergency or advisory, a drought or other emergency to assure the other water needs are adequately met, or are decisions left to the water seller and the gas well user?
- An Invasive Species Control Plan (for already approved sources) is only required at request of the Commission. However, it is unclear how the Commission will have information related to the intended water destination (how will the Commission know where water is going before a transfer process begins?). How will the Commission determine if an ISCP is needed?
- Facilities that discharge wastewater or non-contact cooling water can apply under an APR to become a source of water for natural gas projects. The facilities must demonstrate that the “loss” of the discharge will not adversely affect up or downstream users, groundwater levels, or streamflows, but again, “adversely affect” is not clearly defined. It is not clear what effects or parameters are to be evaluated by either the applicant (under the APR) or the Commission to determine “adverse effects,” nor is it clear how an effect is determined to be adverse. Is a downstream mixing zone analysis or flow analysis required? Will the cumulative impacts of discharge reduction be considered by DRBC? Again, what is the process for determination?

Adams points out that previous approvals did not consider the impacts of the quantity of consumptive use that gas projects represent and that the public is foreclosed under the ABR from the public participation process that they took part in during the original docket approval. There is no process provided for potentially affected parties to obtain and review information and contribute information to the record through a public process. (Adams, p. 4-5) Also, ABR is intended to expedite the review process (less than 30 days as opposed to six to nine month review) but there is no evidence that this furthers the Commission's stated goals of protecting the water resources of the Basin. In fact, Adams states it is not clear that the expedited process will allow for sufficient technical review. (Adams, p. 3) Finally, Adams concludes that the draft regulations fall far short of protecting the water resources of the Basin. (Adams, p. 5)

Aspects of regulation in this section that are repeated in Section 7.4(e) "New water sources for uses related to natural gas development" will be addressed below.

7.4(d)(1)(x): Additionally, invasive control plans should not be limited to aquatic invasives, but must also include land invasives, including plants and animals. Our watershed woodlands are being increasingly ravaged by plant and animal invasives. The loss of healthy woodlands and forests affects the volume and quantity of stormwater runoff, pollution prevent, waterway habitat, water quality and water flows. The land disturbance that accompanies drilling and gas site development is in invitation to invasives that will be accepted and needs to be thoroughly considered, avoided, addressed and responded to. Any responsible plans for addressing invasives, land or water, must not include the use of chemicals, which is itself the introduction of another pollution source to the watershed if allowed to happen.

Section 7.4(d)(2) Approved discharge as a water supply source. We oppose the approval of water withdrawals by ABR as discussed under (c) above. Additionally, for the same reasons under (1) above, we object to the lack of Nonpoint Source Pollution Control Plans under ABR. Also, we do not agree that already approved discharges of treated wastewater or non-contact cooling water should be used for gas drilling but that these should be considered under an individual docket as a new source of water and/or that the discharge permit from the host state and the Commission docket be re-evaluated for impacts of the discharge to the receiving stream. Under Draft Rule Section 7.4(e) there are additional technical review requirements that should apply to all water withdrawals since the depletive and consumptive nature of the water use by gas development substantially changes the potential for impact. Further, a broad, cumulative analysis needs to be done of potential impacts rather than simply considering the vicinity of a "discharge" as is proposed.

Also, these sources of water should be required to meet Commission-adopted water quality standards for all constituents in the wastewater or cooling water. These standards should protect the water resources of the basin, including human health and surface waterway health and the integrity and diversity of aquatic

life and wildlife that are potentially influenced. In addition to the need for enforced water quality standards for these sources of water, we are concerned that allowing discharge water and cooling water to be used will open a loophole that will lead to poorly or partially treated water being used because the Draft Rules do not require individual batch testing of all discharge water that would be used for gas development. While tracking is required, water quality testing or reporting is not. Considering the poor performance of project operators in PA – as discussed in this comment and in expert reprints herein – and the fact that inadequately treated wastewater is being discharged from permitted wastewater facilities in PA today³⁶, it is reasonable to consider that polluted discharge water may be employed in gas development if these sources are allowed to be used as proposed in the Draft Rules.

The proposed provision that the discharge must not “adversely affect upstream or downstream dischargers, downstream withdrawers, or aquatic life”, as discussed by Adams above, is not defined and there is no process for analyzing the potential impacts; all the comments and questions raised above by Adams apply here as well. (Adams p. 12-13) The lack of requirement, for instance, for the preservation of the stream’s hydrologic flow through stormwater volume controls, threatens stream quality and morphology and species.

The question of how aquatic life would be affected, for instance, may well require an analysis of benthic organisms or populations of certain species sensitive to flows, such as mussels. Dwarf wedgemussels live in the Delaware River and are very sensitive to changes in flow regime and water quality changes that could be caused by a change in discharges locally.³⁷ These types of analyses take time and are season specific – the assumption that the use of an approved discharge as a water source will have fewer impacts than a new water source and so therefore needs less review is erroneous and based on false assumptions. The data gaps about the living resources of the Delaware River and its tributaries contribute to the problem of lack of information that is needed to provide assurance that the water resources of the basin are being protected. The Draft Rules inclusion of the use of discharge as a source under the conditions provided should be removed from the Draft Rules.

Parasiewicz points out that the Draft Rules’ stormwater and NPSPCP provisions fail to address the maintenance of a balanced hydrograph in affected waterways. Furthermore, with the Commission’s estimated 18,000 gas wells, Parasiewicz predicts a significant increase in runoff cannot be prevented. Even if there were an attempt made to remedy flow problems with, for instance, stormwater impoundments to meter water into the rivers during low flow periods, the problem of increased water temperature in the summer would remain unresolved. (Parasiewicz p. 14) Only by addressing hydrologic impacts through regulations that require ecologically based flow regimes that provide or mimic natural flow regimes can flow issues be resolved; otherwise the downward spiral of trading off one problem for another is endless and leads to failure to protect the water resources of the basin.

Demicco discusses the shortcomings of the proposed use of approved discharges as source water by ABR (Demicco p. 11-12):

The complexity of potential impacts and the broad range of potentially affected populations should be presented in a public meeting setting with the opportunity for public input into the decision making process with the views of multiple affected parties presented, and not approved as an ABR. ABR should not be allowed in these regulations as previous granting of permits did not include water use for gas development as a possible occurrence and likely did not include a 100 percent consumptive (or more) use of the water in the considerations that informed and resulted in the final decision making.

Further, the discharge permit pollution limits and Total Maximum Daily Loads (TMDLs) were set for particular constituents of the waste water and the water to which the discharge occurs. The redistribution of that water, potentially to a much smaller basin, will require reevaluation, especially for limits such as coliform, phosphates and nitrates. Public input and hearings are required to understand the full impact to the environment, explore all options to meet demonstrated needs, and allow the public the opportunity to meaningfully participate in the decision making process.

It is recommended that ABR not be used to change the condition of use for previously approved discharges and protective water quality standards should be adopted for all water sources, including those from existing uses. (Demicco p. 12)

Section 7.4(e) New water sources for uses related to natural gas development.

Section 7.4(e)(1) General provisions.

Section 7.4(e)(1)(i) Docket approval required. All water use for gas development should require an individual docket approval. The Draft Rules allow for a new water source located within the boundaries of a Natural Gas Development Plan (NGDP) to be approved by an ABR. For the reasons described above including cited comments by Adams and Demicco, we oppose the use of ABR.

If the Commission is assuming that the source water will be located close to the well where it will be used and that argues for a less rigorous approval process, this is a faulty assumption. There is no upward limit of area covered by a NGDP. Therefore, water source within a NGDP can be located a considerable distance from its use area within a NGDP. (Adams, p. 13)

Section 7.4(e)(2) Conditions.

Section 7.4(e)(2)(i) Non-point source pollution control plan. We agree that nonpoint source pollution control plans (NPSPCP) are required for all water withdrawal applications and that the strictest regulations for erosion and sedimentation controls should apply. We point out that the Commission has not adopted any requirements or guidelines for NPSPCPs and that routinely host state regulations are being applied regarding all applications to the Commission.

We advocate and support the development and adoption of specific stormwater management, erosion and sedimentation regulations, and best stormwater management practices by the Commission that

adhere to the stringent requirements the Commission must meet in SPW. We also advocate that the Commission adopt such regulations for the entire basin, not only for SPW.

The host state regulations are not adequate to control erosion and sedimentation and, due to numerous exemptions in host state oil and gas regulations, stormwater throughout the basin is poorly controlled and requires Commission oversight and regulation. Adams provides a Table that compares stormwater management requirements for earth disturbance activities in Pennsylvania, illustrating the inadequacy of the state's regulation for oil and gas activities in Attachment 1 of the Adams report, inserted below:

| | NOI for Coverage under the General (PAG-02) NPDES Permit or Application for an Individual NPDES Permit for Stormwater Discharges Associated with Construction Activities | Application for Erosion & Sediment Control Permit | NOI for Coverage under the Erosion & Sediment Control General Permit for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing or Treatment Operations or Transmission facilities | Permit application for Drilling or Altering a well |
|---|---|--|--|---|
| Required Information | | ESCP | ESCGP-1 | 5500-PM-OG001 |
| Project Description | yes | yes | yes | no |
| Project Area | yes | yes | yes | no |
| Total Disturbed Area | yes | yes | yes | no |
| Timetable for Phases (with acreage disturbed by phase) | yes | yes | yes | no |
| Description of Site | yes | yes | no | no |
| Explanation of consideration of site's Natural Resources in Location and Design of the project, E&S Plan, PCSM Plan) | yes | no | no | no |
| Identification of geologic formations or soil conditions that may cause pollution and description of BMPs to minimize its impact | yes | no | no | no |
| Identification of Pollutants other than sediment in stormwater | yes | yes | yes | no |
| PPC Plan required for use or storage of chemicals, solvents, hazardous wastes or material with potential to cause accidental pollution during earth disturbance | no | yes | yes | no |
| Explain whether fill will be imported, exported or if the site will balance | yes | no | no | no |
| Site Contact information (name, firm, title, etc.) | yes | yes | yes | no |
| Consultant for Project (name, address, etc.) | yes | yes | no | no |
| Compliance Review - Listing by permit number of other environmental permits issued by Department | yes | yes | no | no |
| Narrative to address existing or past violations of any environmental regulations or permits | yes, within last 5 years | yes, current and past violations | yes, within last 5 years | no |
| Post Construction Stormwater Management (PCSM) Plan required | yes | yes | No calculations or measurements required if Section D, 2e indicated as yes to both questions | no |
| Consistency letters required for ACT 167 and Municipal Ordinances | yes | no | no | no |
| Off-Site Discharge Analysis | yes | no | no | no |
| PCSM BMPs must be consistent with... | Act 167 OR PA Stormwater Manual and/or Other Design Standard | | Act 167, local ordinances, or BMPs will manage net increase in runoff volume resulting from 2-year/24-hour frequency storm | |

These difficulties that are not addressed by the Draft Rules will lead to stream degradation and nonpoint source pollution to SPW and throughout the basin from gas development.

Adams explains (Adams p. 13-14):

- If the source is located within Special Protection Waters, a Non-Point Source Pollution Control (NPSPC) Plan is required. Such a plan does not appear to be required in other waters, so addressing issues of erosion & sediment control, as well as stormwater impacts from new water sources, will be left to the states for regulation unless located in Special Protection Waters.
- A NPSPC Plan must meet the more stringent requirements of either the Commission or state, however, it is not clear how this is determined. As described in detail in Attachment 1, approval by Pennsylvania does not assure that erosion & sediment control or stormwater management are adequately addressed for resource protection. Pennsylvania only requires that stormwater be addressed for sites over 5 acres, and further waives the submission of any plans or stormwater calculations if the applicant indicates that, 1) original contours will be maintained or replicated, and 2) stormwater BMPs are employed to address the 2-year volume increase. Pennsylvania's requirements are not adequate to protect Special Protection Waters or other waters. If an Erosion & Sediment control plan is not required in Pennsylvania for sites less than 5 acres, will a New Source in Special Protection Waters be required to prepare a NPSPC Plan? This is not clear.

To adequately address non-point source pollution in Basin waters, the Commission should require that all new water sources prepare and submit a NPSPC Plan and erosion and sediment control plan for all locations, in conformance with the Commission's Water Quality Regulations for a NPSPC Plan. NPSPC Plans should be reviewed by the Commission, and available to the public.

7.4(e)(2): To the extent the DRBC is relying upon the SPW nonpoint source pollution control plan requirements it needs to ensure these requirements are updated prior to finalization and implementation of the draft drilling regulations. The Water Quality Advisory Committee, during consideration of the application of SPW to the Lower Delaware River, acknowledged the need to update the nonpoint source pollution control plan requirements of SPW, i.e. that they were out-of-date and failed to ensure best practices for addressing nonpoint sources of pollution. Failure to undertake this body of work will ensure the gas drilling regulations are deficient in their application of nonpoint source pollution control protections needed to protect SPW waters and downstream communities. No state has a program that is fully up to date with current stormwater science and technology, or standards, and therefore able to ensure a protection of existing water quality from nonpoint source degradation. The state of the art practices must be included in the Draft Rules.

The Draft Rules incorrectly omit the requirement that water withdrawal projects prepare a NPSPCP for the "Area Served" by the project. Prior to approval, the Area Served must be defined and all wells that would use the water from this site must be mapped in order to identify the Area Served accurately. A NPSPCP is to be submitted for the project service area located within the drainage area of SPW (Water Code Article 3.10.3.A.2.e.1) and 2)), not only for the area where the facilities for the water withdrawal project is to be constructed as is implied in the Draft Rules. Section 3.10.3.A.2.e.1 makes it clear that the service area for a withdrawal is the area to be served by that withdrawal, not just the withdrawal site.

Section 2) further reinforces this by requiring that when a project is expanded, the system can only serve an area regulated by a Non-Point Source Pollution Control Plan approved by the Commission. The Commission should amend the Draft Rules to require the applicant to prepare a NPSPCP for all well sites that will be served by the withdrawal.

Section 7.4(e)(2)(ii) Natural diversity inventory assessment. We support the requirement for a NDIA to be prepared for the withdrawal site and that the Commission reserves the right to prepare a separate NDIA at the expense of the applicant. The Commission should require that comprehensive and current project-specific data be gathered for the inventory.

We point out that in PA, PNDis that are prepared are often based on outdated and incomplete information. The State inventories that the applicants draw from are not developed by the State in a comprehensive way with uniform standards. The inventories are developed on an as-needed basis for large areas (sometimes County based) depending on availability of data and resources to complete the inventory. Some PNDI inventories are not based on current information and/or do not cover all of the landscape of a region and often do not contain stream data. These inventories invariably need to be supplemented by project-specific research that inventories all species in flora and fauna communities to provide accurate information. For instance, the National Park Service has inventoried the benthic life in some tributaries to the Upper Delaware River, subject to funding and resources. But data is not available for many streams, particularly headwater streams, as noted elsewhere in this Comment.³⁸

Section 7.4(e)(2)(iii) Metering and recording of withdrawals and transfers. As stated above, Adams queries the specifics of these requirements (Adams p. 12):

The draft regulations indicate that withdrawals must be metered (continuous recording), transferred directly to trucks, and records held at the site. Quarterly reports, including the amount of withdrawal and destination, must be given to the Commission at request of the Commission. Is there a process for public access to this information? Does the Commission have a plan to collect and evaluate the withdrawals and their destinations? Will this information be available quickly in the event of a pollution event or water emergency or advisory, a drought or other emergency to assure the other water needs are adequately met, or are decisions left to the water seller and the gas well user?

Section 7.4(e)(2)(iv) Reporting of withdrawals and transfers. With current technology, reporting can easily and inexpensively be instantaneous and continuing through the use of computer programs. In addition to the obvious advantage of obtaining current information, the information can also be easily available to other regulators, interested agencies, and the public. The Draft Rules should require real-time continuous reporting of all withdrawals and transfers.

Section 7.4(e)(2)(v) Water withdrawal site plan and Section 7.4(e)(2)(vi) Water withdrawal site operations plan. The Draft Rules should require all plans to be completed with the application and prior to approval. In the docket for Stone Energy's water withdrawal, several key plans, such as the operations

plan, were missing yet approval was granted conditional upon its completion.³⁹ This removes access and opportunity for review and comment by the public by placing the review of these plans in the hands of the Executive Director out of public view. This practice is wrong and should not be tolerated in the interest of agency transparency and effective public involvement.

A cumulative analysis of water withdrawals needs to be a mandated part of any water withdrawal site plan, to ensure consideration of all withdrawals on the waterway, habitats, and water quality and water availability. This analysis must assume both consecutive and concurrent withdrawals from all other wells possible in the affected waterway. There appears to be missing text from this provision of the draft regulations; and therefore we are unable to full and appropriately comment on this key provision.

Section 7.4(e)(2)(vii) Notice of construction start and completion. Municipal and public notification should be required in the Draft Rules to allow for adequate local planning. As discussed in this Comment, the exclusion of local officials and emergency personnel in the planning for projects is leading to traffic congestion and other community impacts that could be avoided with proper notice and planning. See Compact Section 3.9 (The Commission shall promote and aid coordination of the activities and programs of...municipal ...agencies)

Section 7.4(e)(2)(viii) Expiration of approval. The Draft Rules should require action within one year with no extension in order to reflect changing regulations and environmental conditions and to avoid “grandparenting” of outdated permit conditions.

Section 7.4(e)(2)(ix) Approval limited to withdrawal. We agree approval only applies to water withdrawal.

Section 7.4(e)(2)(x) Restricted access and operations. We agree the site must be restricted for safety purposes, both for people and wildlife. The Draft Rules should require that the site be posted and fully identified for local information purposes immediately upon the commencement of application procedures and throughout the review and approval process as well upon approval and commencement of construction.

Section 7.4(e)(2)(ix) Other approvals. We agree that Commission approval does not exempt the operator from any other approval. We support the inclusion in this section of local government approvals.

Section 7.4(e)(2)(xii) Floodplain regulations. We oppose the location of any water withdrawal facility in a flood hazard or floodplain area, as discussed elsewhere in this Comment. The Commission’s floodplain regulations have been recognized as in need of major update by the Floodplain Regulation Evaluation Subcommittee and the Flood Advisory Committee to which it reports. Both the FRES and the FAC identified numerous deficiencies, including a need to redefine the regulated floodplain and floodway, in Commission floodplain regulations and recommended to the DRBC Commissioners that

these regulations be updated. Considering the level of importance the Commission's floodplain regulations are playing in the gas drilling draft regulations, and the large degree to which they are being relied upon, these regulations need to be revised and updated in accordance with the FRES and FAC recommendations, with those updates finalized and put into place, before the gas drilling regulations are finalized and applied. Failure to take this step will result in highly deficient regulatory protections for floodplains, waterways and communities and will result in an inequity in how drillers of today will be treated compared to drillers in the future. The current Commission floodplains regulations do not provide a level of protection appropriate as a basis for these regulations.

Section 7.4(e)(2)(xiii) Drought emergency plan. The Draft Rules should require that all operators comply not only with host state drought declarations but with Commission drought plans as well. Drought conditions can vary by geographic area as is evidenced by the history of drought in the Delaware River Basin and the sophisticated drought planning system that the Commission has in place. Also, definitions of key terms that trigger conservation need to be set by the Commission. For instance, the nonessential use definition should be set by the Commission, not state agencies.

Section 7.4(e)(3) Additional submittals and conditions applicable to new surface water withdrawals approved by ABR, docket, or protected area permit.

Section 7.4(e)(3)(i) Invasive species control plan. As stated above, Adams comments that it is unclear how the Commission will know where the water will go for well development and what measures are needed there. (Adams, p. 12) Without mapping of a service area for the water withdrawal that identifies the location of all wells to be served, as is required under the Water Code, an effective invasive species control plan cannot be developed.

Section 7.4(e)(3)(ii) Pass-by flow requirement. DRN opposes and objects to the use of a formula based on the Q7-10 to compute the pass-by flow in a stream where a water withdrawal project is proposed. The Draft Rules incorrectly rely on the Q7-10 as the planning mechanism for stream flow protection.

The nationally recognized Instream Flow Council explains that the Q7-10 is not an instream flow method; it is a flow statistic designed to be used to set the volume of water needed in a stream to meet point discharge water quality standards. It was never meant to be used as a method to set safe minimum stream levels, despite the fact that some States use it. The Instream Flow Council states "The hydrologic statistic has often been misused as a minimum flow for keeping fish alive".⁴⁰ They go on to point out "This method should only be used to determine wastewater discharge criteria... This method does not protect aquatic life (Camp Dresser and McKee 1986) and its use as a standard to do so is inappropriate... The 7Q10 should never be used to make instream flow prescriptions for riverine stewardship... the 7Q10 drought flow is inadequate to conserve aquatic life or ecological integrity."⁴¹ They further explain that "Fish communities can generally withstand near-drought conditions that occur infrequently and for short periods. However, setting such a flow as a long-term condition will not sustain

them. The influence of flow on aquatic organisms includes more than just magnitude and frequency, duration and season are also important. Making such a low flow the norm is like recommending the sickest day of your life as a satisfactory level for future well-being. Use of the 7Q10 persists because it favors off-stream uses. However, it does so by sacrificing the fish and wildlife resources that belong to the public and over which government has a stewardship responsibility.”⁴²

The aquatic life of the stream, fish, the ecological flow needs, water quality, and the stream’s hydrology need to be adequately protected in order to avoid degradation. An alternative method of setting a pass-by flow that takes these factors into account must be developed. The use of a formula based on the Q7-10 will degrade the water resources of the basin.

Considering calculation of low flow, the Commission is required to consider drought in its regulatory and policy decisions. The Q7-10 allows far too much water to be removed from a stream, exposing the waterway to drying up more quickly should drought conditions occur. Demicco explains (Demicco p. 10-11):

Water needed for fracing can be collected and stored over a significant time period in preparation for fracing. Given the ability to plan and estimate the time fracing will occur, allowing pass by flow to be diminished to Q7-10 is simply encouraging poor planning on the part of the gas well operator. No justification is provided for the Q7-10 in the regulations. In fact, high flow skimming of stream flows from rainfall runoff should be used under prescribed conditions, not a stream at or near groundwater base flow. High flow skimming removes the environmental impact of any low flow removal of stream water. In calculating minimum flows, ecological needs and strict flow regime protection should be applied given the time frame for frac preparation. In calculating protective low flows, a mean low flow of several days on a two or three year reoccurrence interval is far more appropriate and should be combined with the implementation of a modeled flow regime mimicking natural flows that does not adversely impact stream ecosystems and habitats as well as instream and downstream conditions and uses.

We recommend, as Demicco states, that a Q3-3, a 3 consecutive day low flow on a 3 year reoccurrence interval, should be applied in addition to a modeled flow that preserves the ecological flow regime protective of instream ecology and habitats as well as instream and downstream conditions and uses. (Demicco p. 11)

Considering the application of a flow regime that will protect the water resources of the basin, we support and advocate for the implementation of a stream flow protection regulation based on the ecological requirements of a waterway.

Parasiewicz concludes that the Draft Rules are inadequate and contrary to current Commission efforts to protect and maintain healthy aquatic populations, which is a declared goal of the Commission. Parasiewicz recommends that an instream flow management plan be developed for the entire basin and

that gas development not commence until evidence is provided that implemented measures from the recommended plan will maintain the ecological integrity of the river system. (Parasiewicz p. 2-3)

Parasiewicz explains that humans have altered natural stream flows, threatening species. Of more than 3,500 species currently threatened with extinction worldwide, one quarter are fish and amphibians; the freshwater mussel is one of the most imperiled with only 25% of the existing species having stable populations. (Parasiewicz p. 5)

Urbanization (especially deforestation) and global climate change have led to degraded stream conditions throughout the United States, including the Northeast. Even the Catskills have not fully recovered from the historic ravages of timber harvest and aquifer depletion, leading to disruption of stream flows and less cold water flows. (Parasiewicz p. 6) The problem is complex and requires coordinated planning and ecological intelligence.

In Upper Delaware River Watershed streams (the Poconos and Catskills), stream changes continue to present a challenge to healthy habitats and the changed hydrological patterns have reduced fish densities and resulted in more generalized fish species rather than specialized riverine species. Due to the length of the Delaware River free flowing main stem, the river itself is exceptionally healthy. Indicators of this include a large number of freshwater mussel species, including the federally endangered dwarf wedgemussel (*Alasmidonta heterodon*), and migratory fish species such as the American shad and American eel. (Parasiewicz p. 8)

Public appreciation of the value of the Delaware River is demonstrated through its famous cold water streams and fly-fishing, Congressional recognition as a Wild and Scenic River, the National Park Service programs, and the many conservation and recreational features accessible to the millions of visitors that come to this remote region from the metropolitan areas of New York, Philadelphia and beyond.

Parasiewicz points out, however, that the Delaware's over-widened, shallow river channels, flashy hydrology with rapidly changing flows, hydropower uses on tributaries, and the diversion of drinking water for New York City place a human footprint on the river. The upstream reservoirs release program can be erratic and habitat conditions are inevitably affected. The dwarf wedgemussel, for instance, needs more habitat protection. (Parasiewicz p. 9)

The Commission has recognized this need for an ecological flow plan based on habitat needs and convened various planning efforts to develop an ecologically based flow regime.⁴³ However, as discussed earlier in this Comment, the Flexible Flow Management Plan (FFMP) does not include measures to protect federally endangered species such as the dwarf wedge mussel (Parasiewicz p. 10)

The Draft Rules should include a water withdrawal permitting rule that is ecologically and scientifically sound, based on the seasonality of biological processes and habitat needs of fauna. Neither the Commission nor the host states have scientifically sound instream flow policies that are ecologically protective. An example of how the Commission's current Q7-10 approach, which is proposed in the Draft Rules as well, does not protect species is the approval of the Stone Energy water withdrawal that allows 75% of the average daily flow of the West Branch Lackawaxen River, a tributary to the Upper Delaware, to be withdrawn all year round for gas development. (Parasiewicz p. 10) Species that are adapted to the current natural flow regime of this undammed high quality waterway will be diminished or will completely perish.

Many research and planning efforts are required to develop the scientific basis for an instream flow plan that will inform regulations. The Commission has identified this need in its Water Resources Management Program and Basin Plan, as discussed earlier in this Comment. Ecological targets need to be fixed and tools such as the reference river concept need to be used. (Parasiewicz p. 11)

The need for a habitat model to inform flow regime requirements is well illustrated by Parasiewicz in his modeling of consumptive withdrawals required for the Commission's projected 10,000 gas wells and how this will impact the dwarf wedge mussel habitat (Parasiewicz p. 12):

In addition to analyzing the total amount of water used by individual mining wells, the cumulative effect and changes in the flow patterns need to be considered. According to DRBC estimates, with adding 10,000 wells the total amount of withdrawal in a peak year should range about 19 mgd, which translates to about 30 cfs. I used this number to model the impact on the dwarf wedgemussel habitat with the MesoHABSIM model developed by Rushing Rivers Institute following the Dwarf Wedgemussel Habitat study. The historical flow records were reduced by approximately 30 cfs and entered to the model for the calculation of a frequency of rare events that would pose a threat to the mussel fauna. Such stress days occur when persistent durations of low flows are exceeded. The model concluded that this simple reduction would double the frequency of persistent subsistence flows. This is critical, because in the past, USGS scientists observed "gaping" or thermally stressed dwarf wedgemussels in 2005. The increasing duration and frequency of such periods could have devastating effects on the fauna and hinder the efforts to restore the mussel populations. Although a MesoHABSIM model for additional cold water fish and invertebrate species is not currently available, it is clear that through increase of water temperature alone, the effects of such extended durations of low flows may have detrimental effects on cold water fish species and macro-invertebrate fauna. The same experiment was conducted by applying the USGS-developed Delaware River Decision Support System (Bovee et al. 2007). The results indicated a sharp decline in habitat availability for the majority of the species, and specifically almost 80% of the reduction of spawning habitat for trout in the West Branch of Delaware (**Exhibit 4**). This simulation still did not include the effects of watershed development as described below.

Since it is very likely that the number of wells will be much higher than 10,000 (some estimates indicate as many as 32, 000), it is obvious that negative effects described above would be even more dramatic.

Parasiewicz points out that the Draft Rules specification of a pass-by flow rule that requires that the Q7-10 flow will remain in the river is based on water pollution standards and is not adequately protective of aquatic fauna. It is not supported by scientific evidence and fails to take into account the seasonality of biological processes. Hence, it violates the Natural Flow Paradigm (Poff et al. 1997), which is a recognized standard in instream flow planning. Although the rule refers to more stringent regulations of host state agencies, those are however also non-existent in PA and NY. (Parasiewicz p. 14) Based on impacts that can be expected to the federally endangered dwarf wedgemussel and other keystone species of the Delaware River, the pass-by flow provision of the Draft Rules is unacceptable and in violation of the Commission's requirements for maintaining existing high water quality and protecting the water resources of the basin.

Section 7.4(e)(4) Additional submittals, conditions applicable to new groundwater withdrawals.

Section 7.4(e)(4)(i) Hydrogeologic report. We agree that a hydrogeologic report should be required for new groundwater sources. The Draft Rules do not propose an effective report protocol.

Demicco explains (Demicco p. 12-14):

An Aquifer Test Plan should be required prior to conducting the required 48-hour test. The Aquifer Test Plan must include the following sections.

1. Detailed background geologic studies including a fracture trace study and field verification of fracture orientation to determine and project anisotropic effects within the aquifer. Based on the orientation of fractures, specific wells can be prioritized for monitoring in the direction parallel to and perpendicular to the suspected direction of anisotropy.
2. The Aquifer Test Plan should also detail conditions for stopping the drawdown test with pass/fail criteria. In a fracture rock aquifer, increasing rates of drawdown as the test continues indicates dewatering of the fracture network. The test should be run for a full 72 hours and until the rate of drawdown over the last 6 two-hour intervals of the test show a decreasing rate of drawdown. The extended length of the test to 72 hours is needed to evaluate dewatering effects within fractured rock aquifers. If a stabilized rate of drawdown cannot be established, the well has limited value and additional evolution and testing of the water resource requested is needed. This could include additional wells, which would also be subject to aquifer testing.
3. The Aquifer Test Plan should also detail conditions for recovery with pass/fail criteria. Recovery from pumping is extremely important in evaluation of recharge to the aquifer. Recovery to a full 90 percent of the amount of drawdown must be required. If the well fails to reach either a stabilized rate of drawdown or does recover

to 90 percent of the total drawdown within 96 hours, the well has failed to illustrate sustainable production.

4. An aquifer test conducted with the above analysis of anisotropy will provide reviewing hydrogeologists with reliable data to evaluate interference effects that will occur with operation of the well. Interference effects are simply the drawdown caused in any well from the ground water withdrawal in another well. Specific wells most vulnerable to interference effects will be identified based not only on lateral distance but based on vertical depth. Well variability both horizontally and vertically requires that aquifer test monitoring not be limited to one well in one particular compass direction, but encompass as many wells as available. Further, varying water quality related to periods of extreme rainfall can occur in fractured rock wells. Given the availability of water level recording instruments, the well(s) identified in the aquifer test as most vulnerable to interference should be equipped with water level and specific conductivity recording instruments.

It is recommended that an Aquifer Test plan be required to evaluate anisotropic features, running the test for 72 hours to evaluate dewatering effects, and add pass/fail criteria to the aquifer test results. Without this accurate test the Draft Rules are not effective because they do not provide the data needed to know if the groundwater resources will be adversely impacted by the proposed withdrawal. Without pass/fail criteria, the report that is required by the Draft Rules is for informational purposes only with no direction regarding decisions to be made by the Commission if a withdrawal has the potential to significantly draw down the aquifer and interfere with existing uses.

Section 7.4(e)(4)(ii) Obligations relating to interference. Interference that is demonstrated by testing can be responded to by a denial of approval by the Commission. It is unreasonable and not protective of existing uses, including water well owners, if complaints and adverse impacts are the primary means of addressing interference. All the follow up suggested in the Draft Rule is fine but it allows harm to be done before action can be taken, which is a violation of the Commission's charge of protection of water resources and preventing harm.

Section 7.4(f) Importation of water for uses related to natural gas development. We agree that that Commission determinations regarding applications for the importation of water for uses related to natural gas development must be made in accordance with Section 2.30 of the Commission's Water Code.

Section 7.4(g) Use of recovered flowback and production water. We oppose the reuse of these fluids as discussed in the Comment under Section 7.4(a).

Section 7.5 Well pads for Natural Gas Activities.

Section 7.5(a) Purpose and Applicability.

Section 7.5 (a)(1) and Section 7.5 (a)(2). We agree that natural gas well pads require regulation by the Commission in order to meet the Commission's statutory requirements and planning goals. As discussed under Section 7.2, a definition that specifically defines a well pad is crucial; the ambiguity about the well pad definition makes it difficult to fully address gas activity impacts under this Section. As discussed under Section 7.1 Scope, to address all natural gas activities, the Draft Rules should include more than gas well pads, water withdrawals and wastewater.

Section 7.5(b) Administration.

Section 7.5(b)(1) and Section 7.5(b)(2). See Comments regarding Sections 7.3 and 7.4.

Section 7.5(b)(3) Siting restrictions.

Section 7.5(b)(3)(i). We agree a well pad should not be located in the Flood Hazard Area of any waterway (defined as the 100 year floodplain). This is more stringent than the host states. Additional requirements should be added here. First, there are many floodplains that are not delineated due to the lack of Federal Emergency Management Agency mapping. Some maps are outdated (major floods have occurred and/or stream locations have shifted) and many headwater and first order streams are not routinely mapped. In this event, the floodplain must be mapped at the expense of the applicant by a professional objective party based on riparian soils and available flood and stream data.

Second, a buffer should be added that delineates an off-limits area adjacent to the flood hazard area based on riparian soils. Identification of riparian soils should be accomplished by site specific soil testing and the employment of available Soil Survey information. The buffer should measure 500 feet added to the outside limits of the Flood Hazard Area for optimum protection⁴⁴. The buffer must be kept in natural vegetation and not disturbed, compacted or built upon.

Third, floodplains and their buffers need to be kept in native vegetation and not disturbed. The Draft Rules should require that the floodplain areas and buffers that are set as off-limits should be kept naturally vegetated to protect water quality, reduce runoff, and prevent land cover and hydrological changes from gas development that can result in downstream flooding. The Commission's Flood Advisory Committee published a report that states⁴⁵:

Floodplains vegetated with trees and shrubs can be four times as effective at retarding flood flows as grassy areas. Naturally vegetated floodplains are generally layered with leaf and organic matter that result in organic soils with high porosity and a greater capacity for holding water. More than just being an area that can help address flooding issues in a community, the floodplain, in this natural state, is a riparian ecosystem that needs the overbank flows that the natural watershed's hydrology provides in order to remain healthy and in balance.

The floodplain and buffer should be kept in natural condition to support and protect water quality and flow regime in the adjacent waterway. The Commission's floodplain evaluation subcommittee report to the Commission's Flood Advisory Committee states that:

A naturally functioning floodplain is a hydrologically important and dynamic component of a watershed. In addition to being environmentally sensitive and ecologically diverse, floodplains provide flood storage and conveyance, protection of water quality and recharge of groundwater.

A regulatory floodplain may, or may not, encompass the natural floodplain, the area needed a watercourse to maintain its natural biologic, geomorphic and hydrologic functions. Instead, regulatory floodplains are adopted standards designed to guide floodplain development and lessen the effects of floods on the built environment.

.....
It is important to acknowledge that floods do not stop at regulatory floodplains, nor does the regulatory floodplain define the limit of potential flood damage or losses.

Background: Existing flood hazard area maps greatly underestimate the limit of floodways along the main stem Delaware River and other waterways within the Delaware River Basin. The flood hazard area, or floodplain, is the area along a waterway that is expected to be or has been inundated by floodwaters. The floodway, which is the inner portion of the flood hazard area nearest the stream or river, is the most dangerous area that carries deeper flows and higher velocities during a flood. New construction of structures is generally prohibited in floodways because it is unsafe and obstructs the passage of floodwaters, although removal of vegetation and construction of parking or other nonstructural activities while having an impact are often allowed. The flood fringe, or areas immediately adjacent to floodways where development is commonly allowed are often subject to flood depths and velocities similar to those of the floodway.

The Flood Hazard Area, as defined by FEMA, is composed of a floodway and a flood fringe. The flood fringe is the portion of the floodplain that lies outside the floodway. Floodwaters generally move more slowly in the flood fringe as compared with the floodway, and the flood fringe serves to temporarily store large volumes of floodwater during a flood. The space that floodwaters occupy on a given site during a flood is referred to as the "flood storage volume" of that site.

When structures or fills are placed in a flood fringe, it occupies a space that would otherwise be filled with floodwaters during a flood, thus reducing the flood storage volume on the site. If a significant volume of floodwater is prevented from occupying a given area, excess floodwater will instead occupy neighboring and downstream properties, thus worsening flood conditions on those sites. Unless properly managed, development within floodplains can exacerbate the intensity and frequency of flooding by increasing stormwater runoff, reducing flood storage, and obstructing the flow of floodwaters. Structures constructed in the flood fringe are subject to flood damage and

threaten the health, safety and welfare of both the people who occupy them and emergency responders who respond in times of flood emergency.

Historically, the earliest settlements along the eastern seaboard were established along navigable waters. As a result, many of the Delaware River basin's older communities lie partially or completely within floodplains. As development has continued within the basin over the years, increased impervious cover in the form of roads, buildings and parking lots combined with the destruction of forest and wetlands for development and agriculture has increased peak rates and the volume of runoff flowing to the streams and rivers within the basin.

Development within the floodplain obstructs flood flows and compromises the flood storage and peak attenuation contributions of a natural floodplain. In addition, it knowingly places structures, infrastructure and people in the very locations that are known and expected to be subject to flooding and flood damages. As a result, flooding that naturally occurs along waterways has become progressively more threatening and damaging to people, buildings and infrastructure as a combination of increased runoff, decreased vegetation and storage absorption capacity and additional development in floodplains occurs. It is expected that these negative trends will continue so long as buildings and structures continue to be placed in the floodplains of the streams and rivers of the Delaware River basin.

Recommendation: Protect the flood fringe in a naturally vegetated state and limit development including, but not limited to, structures, infrastructure, impervious surfaces, fill, grading and removal of vegetation.

Fourth, the floodplain regulations of the Commission have been recognized as in need of major update by the Floodplain Regulation Evaluation Subcommittee and the Flood Advisory Committee to which it reports. Both the FRES and the FAC identified numerous deficiencies, including a need to redefine the regulated floodplain and floodway, in the DRBC floodplain regulations and recommended to the DRBC Commissioners that these regulations be updated. Considering the level of importance the DRBC floodplain regulations are playing in the gas drilling draft regulations, and the large degree to which they are being relied upon, these regulations need to be revised and updated in accordance with the FRES and FAC recommendations, with those updates finalized and put into place, before the gas drilling regulations are finalized and applied. Failure to take this step will result in highly deficient regulatory protections for floodplains, waterways and communities and will result in an inequity in how drillers of today will be treated compared to drillers in the future. The floodplains regulations in place today at the Commission do not provide a level of protection appropriate as a basis for these regulations.

Section 7.5(b)(3)(ii). We agree that slopes should be avoided. 20% or greater is not an adequate off-limits area however. First, the definition should be more specific; it must state over what distance the slope can occur. Such as: "...as measured over any minimum run of 10 feet. Steep slopes are determined based on contour intervals of two feet or less".⁴⁶ Second, steep slopes are an obvious bad location for a

well pad, considering the body of scientific research that shows that steep slopes are not stable and need to be vegetated and soils need to be intact to avoid erosion, sedimentation and slope instability. But slopes in excess of 15% are considered steep and in need of protection from disturbance, particularly any structure or any activity with the potential for point or nonpoint source pollution releases.⁴⁷

For instance, the Lehigh County PA Comprehensive Plan classifies 15% slopes or over as steep and derive their information from the Soil Conservation Service's soil survey classifications. Industrial activities are discouraged on slopes of 8-15% and 15-25% slopes are considered only suitable for low-density residential, limited agricultural and recreational uses, as shown in Table 1 from the report.⁴⁸

TABLE 1 Degree of Slope

| Degree of slope | Development Potential |
|------------------------|--|
| 0% to 3% | Generally suitable for all development and uses. |
| 3% to 8% | Suitable for medium density residential development, agriculture, industrial and institutional uses. |
| 8% to 15% | Suitable for moderate to low-density residential development, but great care should be exercised in the location of any commercial, industrial or institutional uses. |
| 15% to 25% | Only suitable for low-density residential, limited agricultural and recreational uses. |
| Over 25% | Only used for open space and certain recreational uses. |

Source: Soil Surveys of Lehigh/Northampton Counties, Pennsylvania, Soil Conservation Service. 1963, 1974.

Section 7.5(b)(3)(iii). We agree that gas well pads should not be placed in an area that serves as a critical habitat for a federal or state designated threatened or endangered species. We do not agree that host state mitigation measures should be accepted to allow such intrusion. Buffers that are recommended on a species-specific basis, as recommended by the appropriate agency or scientific body. The Commission should conduct research to inventory these species and applicants should be required to engage professionals to research and report to the Commission. As discussed in this Comment, host state NDI reports are not reliable.

Section 7.5(b)(4) Setbacks. The setbacks in the Draft Rule are not protective of water quality and water resources of the basin. Setbacks should be based on scientific analysis and research. No setbacks should

be deferred to the host state. There are no scientifically valid setbacks in existing regulations in the host states.

Section 7.5(b)(4)(i) Water body, Section 7.5(b)(4)(ii) Wetlands, Section 7.5(b)(4)(vi) Surface water supply intake, Section 7.5(b)(4)(vii) Water supply reservoir, Section 7.5(b)(4)(viii) Public water supply well, Section 7.5(b)(4) (ix) Domestic water supply well.

First, there are many features that are not identified that should have setback distances established such as open pits, water basins, chemical storage facilities, or tanks. These features should have to comply with the same setbacks that apply to the gas well and well bore as discussed below. Host state regulations neglect to offer adequate setbacks for many of these features as well. Second, the measurement of the limits of the area to be set back from should be defined. The Draft Rules 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). (Rubin, p. 32) Setback distances should be measured outward from this outer boundary. Third, linear distance should be based on subsurface impacts as well as surface impacts. Demicco points out several deficiencies in the proposed apparent underlying rationale for the setbacks in Draft Rules (Demicco p. 15):

In general, these regulations need a “Basis and Background Document” providing scientific justification for setback requirements. The failure in Dimock and the widespread nature of gas migration illustrate that well failure is a vitally important consideration in determining setback requirements and is a consideration not taken into account by the apparent generic setbacks proposed in these regulations. The setbacks proposed in the regulations seem to only attempt to address threats proposed from simple surface contamination, surface runoff problems and shallow ground water contamination. The proposed setbacks are not adequate to meet that goal and certainly are not adequate to meet a goal of protection of water resources from subsurface sources of pollution that accompany natural gas extraction practices.

The setbacks proposed to address simple shallow ground water and surface water issues in these regulations and the setbacks needed to prevent threats presented by deep grout failure differ by orders of magnitude. This illustrates the critical importance of well construction, grouting, maintenance, and closure to the protection of Basin resources and underscores the importance of DRBC adaptation of stringent well drilling regulation in concert with member states.

Rubin investigated a scientific basis for setbacks for this Comment (Rubin p. 32-26):

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, and 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 hill slope 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 is 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 throughout 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. See additional detail regarding recommended step-drawdown testing in the bulleted section above.

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.

Rubin also discusses the impacts that hydraulic fracturing can have on water wells and aquifers and recommends rigorous testing to be able to track impacts and gather information that may help to avoid catastrophes (Rubin p. 54-57):

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. Mapping of existing fractures should be done by DRBC before promulgating regulations in order to assess the probability of risk of contamination.

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 many 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.

Section 7.5(b)(4)(ii) Occupied Homes, Section 7.5(b)(4)(iv) Public Buildings, Section 7.5(b)(4)(v) Public Roads.

Setbacks for features used by humans such as homes, buildings (such as schools, hospitals, playgrounds, and day care centers,) and roads need to be set based on human health and public safety factors. There is no justification to rely on the minimal setbacks provided by the host states. The large number of accidents and spills in PA, for instance, make the point that catastrophic events do occur at well sites and that extremely hazardous materials are routinely used on these sites and can be released from a site quickly and without any control over a large area.⁴⁹

To allow human activities within only 200 feet or less, as state regulations allow, is inviting disaster for human beings in the case of catastrophes and in the case of everyday air emissions, long term exposure can lead to health problems, especially for local residents.⁵⁰ Setbacks are insurance that some impacts can be avoided or mitigated; there is no reasonable justification for putting people in harm's way. Harvey points out that the surface siting criteria in the Draft Rules do not provide sufficient setbacks from sensitive features, including homes, public facilities, and roads and that no justification is provided for the proposed setbacks in the Draft Rules. Harvey explains why setbacks are needed for safety reasons (Harvey p. 26):

Blowouts can eject drilling mud, gas, oil, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. These pollutants can then be further transported in the subsurface or on the surface, creating a large area of contamination in a very short amount of time.

Harvey points out that the Draft Rules do not set off-limit areas for uniquely sensitive features, which is a mistake and is done in other states (Harvey p. 27):

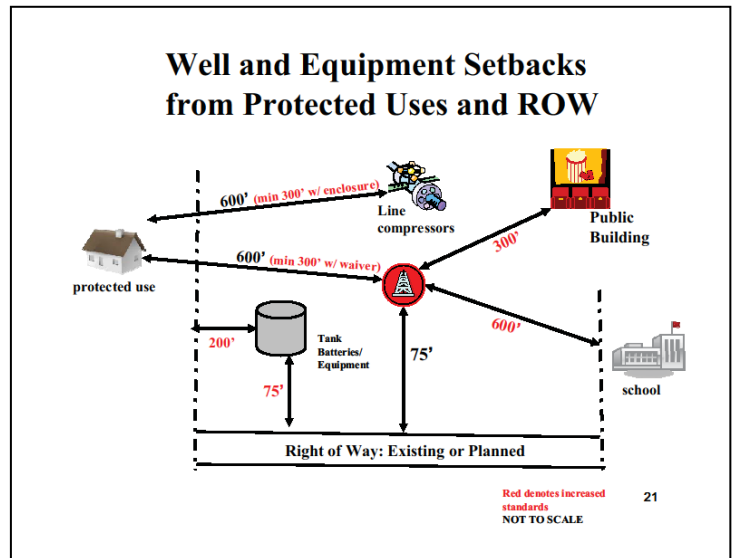
DRBC's Proposed Regulations do not identify areas within the Delaware River Watershed that warrant special protection. DRBC's regulations should include a map identifying areas within the Delaware River Watershed that warrant increased setbacks, seasonal operation constraints, and/or surface use prohibitions.

In Alaska, along the famous Kenai River, surface entry of oil and gas wells and the siting of related facilities are strictly prohibited on lessee tracts along the river (Kenai River Special Management Area). Surface entry of oil and gas wells and the siting of related facilities are prohibited on state game refuges, critical habitat areas, and recreational use areas in Alaska's, Cook Inlet Area.^c Additionally, in Alaska exploration and production operations are generally prohibited within half a mile of the coastline, major rivers, and areas that receive heavy recreational use. Furthermore, exploration and production operations may be required to minimize sight and sound impacts by providing natural buffers to conceal facilities and limiting drilling activities to low use seasons.^d

On the Alaska Peninsula, oil and gas facilities are prohibited within a half mile of: the coast; barrier islands; reefs and lagoons; and major river systems. Oil and gas facilities must be setback 1,500' from all surface drinking water resources. A reduction in these setback buffer zones is only allowed, if the lessee makes a technical and scientific showing that the buffer is not feasible and prudent, and a different setback is environmentally preferred. No oil and gas wells or facilities are allowed at all within the Bristol Bay Fisheries Reserve.^e

These Alaska examples illustrate that in other states water resources, critical habitat areas, and recreational use areas are provided substantial protections from oil and gas development. Alaska leans heavily of the use of directional drilling technology to position surface drillsites in low impact locations.

Another relevant comparison is the setback requirements implemented in the urban area of Fort Worth, Texas. Even in the urban area of Fort Worth's well and equipment setbacks (300-600') are larger than DRBC's proposal of 200'-500'. Fort Worth's setback requirements are shown in the diagram to the right.^f



Daniels discusses that there are a large number of wells that are expected and that will be approved on a case by case basis with no cumulative impact considerations. Also, the shale deposits which are being leased now are located in the Special Protection Waters of the river and this will expose the most

^c Alaska Department of Natural Resources, Division of Oil and Gas, Cook Inlet Areawide Oil and Gas Lease Sale, Final Finding of the Director, Volume I, January 20, 1999.

^d Alaska Department of Natural Resources, Division of Oil and Gas, Cook Inlet Areawide Oil and Gas Lease Sale, Final Finding of the Director, Volume I, January 20, 1999.

^e Alaska Department of Natural Resources, Division of Oil and Gas, Alaska Peninsula Areawide Oil and Gas Lease Sale, Final Finding of the Director, July 25, 2005.

^f Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009.

sensitive and vulnerable areas of the basin to the effects of gas development. He recommends that the Commission err on the side of caution while it develops extensive data and weighs impacts. In the meantime, locations in the basin that are the most vulnerable such as slopes, conservation zones, and aquifer overlay zones (where aquifer recharge is the greatest), wetlands, and important wildlife areas (including PNDI sites) should be considered for designation as off-limits areas for any gas development. He concludes (Daniels, p. 9):

The proposed Delaware River Basin Commission Natural Gas Regulations of December 9, 2010 (DRBC 2010a) are well-intended but are not adequate for managing thousands of applications for natural gas wells. The large number of applications means that neither the traditional case-by-case approval approach nor the Natural Gas Drilling Plans (NGDP) will include a thorough consideration of the cumulative impacts on water supplies and water quality of existing and new natural gas wells.

Section 7.5(b)(5) Spacing. The Commission must put in place explicit spacing requirements for natural gas wells drilled in the Delaware River Basin. Pennsylvania has failed to put in place this important requirement which essentially puts the industry in charge of spacing to serve their own interests and sets no spacing limits on the industrialization of the landscape, allowing vast gas fields to develop. New York has a spacing law but allows infilling with vertical wells, essentially nullifying any benefit of reducing the footprint of well pads.

The claim that allowing many wells to be placed on one pad reduces environmental impacts is speculative and not justified scientifically. For instance, more wells on a pad means more intense use of the pad, more emissions from the pad, more equipment and more activity on the pad. And, after construction and during production, it means more finished infrastructure on the pad and more continuing environmental impacts such as from volatile organic compounds that are vented from the condensate tanks that are required to bleed off any liquid hydrocarbons that flow from the well as produced water or mixed in with gases. It means more handling and offloading of hazardous condensate and produced water, which is highly toxic as discussed in these Comments. More tanks mean a larger permanent impervious surface, more compacted roadways and driveways, more regular ongoing truck traffic to and from the site to transport liquid hydrocarbons off site. These environmental impacts must be considered and weighed when evaluating the claimed benefits of multiple wells on one large pad. This is particularly true since pads can be placed as closely to each other as the industry wants, since no spacing requirements exist. Also, when considering spacing, the space between wells on a pad should also be regulated by the Commission and safety features regarding all phases of well development should be considered in setting the spacing of well bores.

The Commission itself must set spacing requirements in the Draft Rules because it is the only entity that will be looking at the affects of gas drilling from a basinwide perspective and as such is the only agency that will have the full body of information, knowledge, perspective and power necessary to ensure consistent and necessary spacing requirements that will ensure the appropriate level of protection.

Specific space limitations/requirements are also essential for ensuring the needed level of knowledge about what full drilling build out could look like, which is a fundamental and vital body of knowledge necessary for informing creation of gas drilling regulations (including DRBC's regulations) as well as informed decisionmaking on every permitting/docket/drilling proposal put forth.

Section 7.5(b)(6) De minimis change. We do not support the allowance of any changes, and do not consider a 100 foot change in location to a well pad to be de minimis. If there continues to be such a provision in the regulations not only should it be limited by all siting and setback requirements in the Draft Rules, but it should also require a demonstration of need and no harm to be allowed.

Section 7.5(b)(7) Inspection and Section 7.5(b)(8) Timing. See Comments above.

Section 7.5(b)(9) Variances.

No variances should ever be allowed from the requirements of the Draft Rules.

In the case of (i) allowing a variance that would result in placement of a well pad in the floodway is extreme and should never be allowed. The ramifications for downstream users of the increased fill, impervious surface, loss of floodplain soils and vegetation, and placement of toxic chemicals is too tremendous to be acceptable, ever.

In the case of (ii), mitigation measures should never be the basis of a variance determination -- if the operator could have undertaken steps to reduce the environmental and community impacts of their project they should have undertaken these steps in the first instance. It is not appropriate to reward project operators with failing to take all protective measures and steps in the first instance by allowing them to use such actions as a justification for variance later.

Harvey points out that "undue burden" has no established criteria, which leaves it open to interpretation. (Harvey p. 26) Adams points out that the requirement to show the requested siting is "equally protective" is also vague and lacks specific criteria. (Adams p. 15) Adams goes on to explain (Adams p. 15):

If "equally protective" is the same as meeting state requirements for issues related to erosion & sediment control, spill control, water resource protection, etc., then the additional siting requirements imposed by the Commission have little value, as the state requirements in Pennsylvania are not adequate (Attachment 1) and state requirements in New York are still undefined. Further, it is still unclear how the mapping and submission requirements imposed by the Commission (at a scale of 1:2000) will provide for a sufficient level of review to protect the resource, as discussed later in this section, and spacing requirements are based on the state requirements, not the Commission's. For the siting requirements to have meaning, variances should not be permitted, most especially as related to critical habitats for threatened or endangered species.

Further, to allow the Executive Director to grant waivers without a Hearing hides this important decisionmaking from public view and participation. There should always be the requirement of a public hearing considering the tremendous level of harm that would result either in short term catastrophic impacts or long term far reaching impacts.

Section 7.5(c) Natural Gas Development Plans.

Section 7.5(c)(1) Applicability. The requirement for a Natural Gas Development Plan (NGDP) seems to be an attempt by the Commission to address cumulative impacts. However, there are three problems with this. First, there are several allowances for exemptions, waivers, phasing and division into separate units that substantially undermine the applicability of the planning requirement. Second, the review threshold is too high. Third, it is unclear how the information that is required for a NGDP will be used for planning purposes. For instance, will it limit development based on the aspects of the reports that are required to be submitted (i.e. circulation plan?)

Adams explains how the many ways to avoid NGDP requirements undermines this provision in the Draft Rules (Adams p. 16-17):

A project sponsor may request to divide their basin-wide leaseholdings into separate leasehold units (7.5.c.1). It is unclear if this means that a separate NGDP will be required for each portion of the divided leasehold, and if each subdivided portion may submit five well pad applications before NGDP approval. There is no limit indicated for how many separate leaseholds the project sponsor's holdings can be divided into, or any indication of the smallest allowable area (i.e., can a leasehold be divided into areas much smaller than 3,200 acres, or must each subdivided lease holding be at least 3,200 acres)? Is each subdivided leasehold then allowed five well pad applications, while the NGDP is under review? This is not clear.

There also does not appear to be any limit or restriction to the number of well pads that can apply for dockets under an approved NGDP (Section 7.5.f). In other words, once a NGDP is approved, is there any limit on well pad approvals, or any basis defined for considering limits on the number of well pads allowed?

The threshold for the NGDP is too high and does not include exploratory well pads, "stratigraphic well" pads (no definition provided), low volume hydraulically fractured well pads, or high volume hydraulically fractured well pads unless the project sponsor plans to drill more than 5 well pads or has leaseholdings that encompass a total of over 3,200 acres. An Approval by Rule can even be used if certain conditions are met, even if no NGDP has been prepared as per 7.5.c.3.e.

Further, the projects captured should not just be for projects the project sponsor is currently planning to undertake, but should include planning for all possible drilling and development on the site -- i.e. "drilling build out" -- to ensure the DRBC has full information on potential cumulative effects of lands

used for gas well development. While a project sponsor may not today be planning to drill in a particular spot, they may undertake drilling on other land over time, either themselves or by future owners of their leasehold lands, and so it is important that the DRBC fully understand the ramifications of all potential land use as they engage in decisionmaking. Therefore, all decisionmaking should be based upon a build-out scenario.

Harvey points out that there is no requirement for seismic exploration and there is very few limits on exploratory drilling, which is an oversight that should be corrected. Reports prepared for the DRBC Administrative Hearing explain why exploratory wells can be expected to have substantial impact on the water resources of the basin. Harvey further explains why the threshold for production operations is too high (Harvey p. 16-18):

DRBC's Proposed Regulations exempt large numbers of exploration and production wells from DRBC review. For example, if gas wells are drilled on an 80 acre spacing, and a 3,200 acre NGDP review threshold is allowed, 40 wells can be drilled before triggering the review threshold. Or, if multiple high-angle wells are drilled from a single well pad (e.g. 4-6 wells per pad), then the 5 pad review threshold could result in 20-30 wells before triggering the review threshold; 10-12 wells per pad could result in 50-60 wells before triggering the review threshold.

DRBC has not provided scientific or technical information to show why hydrocarbon production operations smaller than the 3,200 acre or 5 well pad review threshold, or exploration activities, will not impact the Delaware River Watershed.

Gas reservoirs are often produced on 160-640 acre spacing; however, some areas of the Marcellus and Barnett shales are being drilled much tighter (40-80 acre spacing, and potentially as low as 20 acre spacing).

The Pennsylvania Oil and Gas Conservation Law does not apply to formations that do not penetrate the Onondaga horizon or to formations that are less than 3,800', where the Onondaga horizon is 3800' or less from the surface. Since the Marcellus Shale is shallower than the Onondaga horizon, as shown in the diagram to the right, the Pennsylvania Oil and Gas Conservation Law does not apply to the Marcellus Shale. Since the Pennsylvania Oil and Gas Conservation Law does not apply to the Marcellus Shale, Marcellus Shale development is not subject to Section 4 (prohibition of waste,^g inefficient spacing of wells,^h or unitization

| Sys-tem | Western Pennsylvania | Northwestern New York |
|-----------------|-----------------------|---------------------------------|
| Middle Devonian | Harrell Shale | Genesee Fm. |
| | Tully Limestone | Tully Limestone |
| | Mahantango Formation | Moscow Shale |
| | | Ludlowville Shale |
| | | Skaneateles Shale |
| | Marcellus Shale | Marcellus Shale Tioga bentonite |
| Lower Dev. | Selinsgrove Limestone | Onondaga Limestone |
| | Needmore Shale | Bois Blanc Fm. |

^g Including allowing oil, gas or water to migrate to a different stratum, or unnecessary loss of oil or gas at the surface.

^h Drilling more wells than are required to efficiently and economically recover the maximum amount of oil and/or gas from a pool (formation).

requirements).ⁱ This means that host state laws and regulations do not provide adequate protection against the potential for very high well density in the Delaware River Watershed.

In NYS, the statewide gas well spacing rules were extended to the Marcellus Shale, meaning that gas shale wells are typically drilled on 40-160 acre spacing. However, an operator can apply for a spacing exemption to drill in-fill wells on a tighter well spacing, meaning the well density in the Delaware River Basin could be between 20-160 acres.

DRBC's own experts explain the potential for large scale impacts to the Delaware River Watershed:

"The Marcellus Shale formation in northeastern Pennsylvania and southern New York underlies about 5,000 square miles or one-third of the 13,500 square-mile Delaware River Basin." . . . "Over 15 million people (approximately five percent of the nation's population) rely on the waters of the Delaware Basin for drinking, agricultural, energy and industrial use, but the watershed drains only four-tenths of one percent of the total continental U.S. land area.

The 5,000 square-mile area common to the Marcellus Shale and the Delaware River Basin includes a 73.4-mile stretch of the Upper Delaware Scenic and Recreational River, which snakes gracefully through the rural countryside of green rolling hills (Figure 2). Within this same area, the Marcellus Shale includes some of the most promising sections in terms of the thickness of organic-rich shale."

It is estimated that a total of 16,000-64,000 wells could be drilled in the Delaware River Basin. This estimate was developed using the planning assumption put forth by DRBC's expert O'Dell.

O'Dell assumed for planning purposes that:

- 80% of the 5,000 square mile Marcellus Shale formation underlying the Delaware River Basin will be developed (4,000 square miles);
- wells will be initially drilled on an 160 acre spacing (4 wells per square mile); and
- later infill drilling will likely cause a well spacing density of 40 acres (16 wells per square mile).

Using a range of well spacing (40-160 acres), a total of 16,000-64,000 wells could be drilled in the Delaware River Basin.

Assuming an average of six (6) horizontal wells drilled from a single drillsite, between 2,700 and 10,700 new drillsites could be developed in the Delaware River Basin. The number of new drillsites could be substantially higher if multiple wells are not co-located on a drillsite.

ⁱ Pifer, R.H., Penn State, The Dickinson School of Law, The Rule of Capture in Pennsylvania Oil and Gas Law, 2009.

While DRBC assumes that multiple wells will be directionally drilled from each drillsite, there is no requirement for operators to use this technique. This opens up the possibility of single well drillsites, and in turn a much more significant surface impact.

How the information that is required to be submitted for a NGDP will be used to plan the project sponsor's build out is unclear. Further, it is unclear how the multiple plans that would be submitted and approved would be used in planning decisions by the Commission. Adams questions how the NGDP will provide for cumulative impact analysis or what criteria the Commission will use to assess these impacts. (Adams p.17)

Demicco points out (page 14):

The Natural Gas Development Plans (NGDP) (Section 7.5) appear to be an attempt to quantify future gas development plans. However, there does not appear to be any goal or process by which cumulative effects of the thousands of gas wells will be assessed, quantified or mitigated. Only the Suspension of the Rules of Practice and Procedure (RPP) illustrates the DBRC concern with small cumulative use of water resources. Individual pads will increase runoff and diminish ground water recharge by a certain amount, while staging areas, roads, driveways, and other construction and production activities will compact soil. Storage lagoons also diminish recharge to the site aquifer. Buried gas lines can provide preferential pathways for shallow ground-water drainage and contaminant migration, potentially resulting in the dewatering of shallow ground-water systems. Despite these impacts, however, the cumulative effects from all the well pads on water resources are not directly addressed through the regulation. The NGDP plans will inventory resources but fail to ensure action to avoid degradation to SPW, which includes requiring protection of recharge to groundwater and the healthy base flow of streams.

It is recommended that resource inventories should be followed by a proposed plan for how these resources will be conserved and pollution and degradation will be avoided. The Commission then should require its approval based on basinwide cumulative impacts and with the benefit of thorough review by the public and other agencies that have expertise in various aspects of natural resource conservation. (Demicco, p.15)

Section 7.5(c)(3) NGDP Application Requirements.

Section 7.5(c)(3)(i) Lease Area Map, Section 7.5(c)(3)(ii) Landscape Map, Section 7.5(c)(3)(iii) Constraints Analysis Map, Section 7.5(c)(3)(v) Monitoring Program.

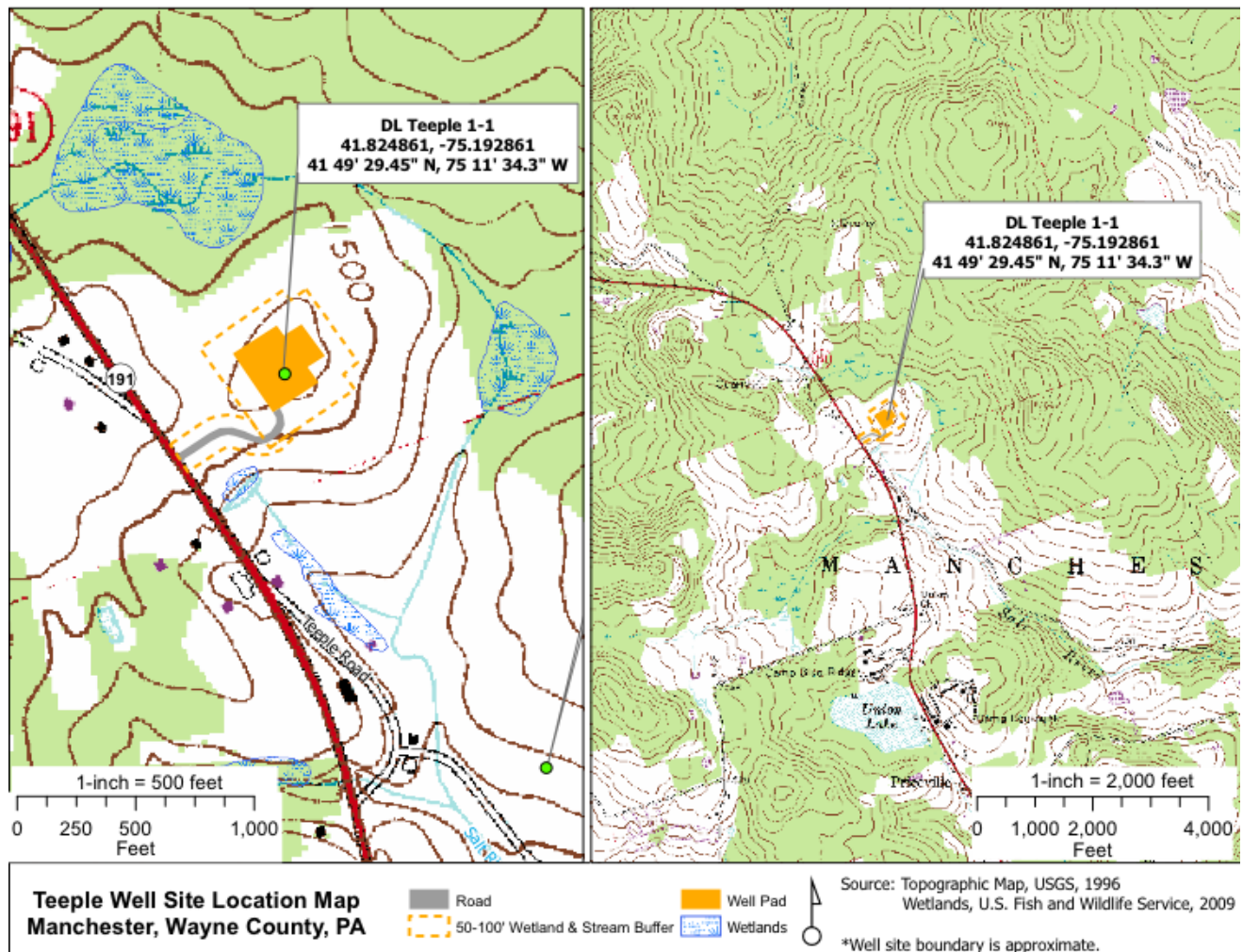
The mapping required is an improvement over host state requirements and we agree accurate mapping is essential. Adams offers these suggestions regarding the mapping for a NGDP, the same mapping requirements as required for Well Pad Dockets or ABR. (Adams 17-18):

Essentially, the mapping must indicate leaseholds intended for development (within 5 year increments), and map geography, property and mineral rights, roads and rights-of-way, wellhead protection areas, hydrologic features, soils, slopes, critical habitats, natural heritage sites, and forested landscapes. This level of mapping requirements represents a significant improvement over the current level of information required at the state level in Pennsylvania.

However, as discussed previously, at a scale of 1 inch = 2000 feet, it is difficult to determine many of these features adequately, or to map the information in a meaningful way. For example, USGS 7.5 minute quadrangles typically provide contours at 20-foot intervals. A 15% slope would translate into 0.067 inches between contours, and a 20% slope is 0.05 inches between contours. These small distances are difficult to distinguish or accurately map, and many small areas of steep slopes that could be impacted by well pad construction are likely to not be represented. Similarly, headwaters, wetlands, and springs are unlikely to be represented accurately on a 7.5 minute quadrangle. To accurately locate and identify all natural features, mapping for the well pad area should be site specific and developed at a scale that adequately provides information, such as 1 inch = 200 feet or less. This is common practice for other development projects, and well pad mapping should not be allowed to rely solely on existing 7.5 minute quadrangle information.

Adams further points out:

For example, Natural Gas Development Plans (for holdings over 3,200 acres) require mapping of important natural features at the 7.5 minute USGS quadrangle scale of 1-inch = 2,000 feet. At this scale, a five-acre well pad site would measure approximately 0.25 inches square (Figure 1). This is hardly detailed mapping that can reflect important natural conditions and features, or the potential impacts of proposed activities.



**Figure 1. DL Teeple 1-1 Well Site Location Map in Altering Scales;
 1"=500' and 1"=2,000' Respectively**

Section 7.5(c)(3)(iv) Circulation Plan. We agree that mapping of roads and rights of way for vehicles, pipeline or utility access, pads, compressor stations, and other equipment is necessary. This is very important because of the lack of regulation of gathering or feeder pipelines by the host states, and discussed elsewhere in this Comment. While a map does not offer regulation, it starts the first step of showing location. The Draft Rules do say that linear infrastructure should be collocated “whenever feasible.” Again, this is an important first step that starts a regulatory framework that is sorely missing and needed in regards to pipelines from gas wells to larger regulated pipelines. But there is no definition of, or criteria, that define what “whenever feasible” means. There is also no specificity about co-location and no information about how the circulation plan will be used or if it will serve a purpose of mitigating or avoiding adverse impacts. We oppose the Executive Director being allowed to give approval to changes to the plan and we advocate for public and local and other government unit input.

Section 7.5(d) Natural gas well pad docket application requirements. A map only showing the required features within 0.5 miles of the well pad site is inadequate. Based on discussion in this Comment on Section 7.5.b.4, mapping must be based on the expected location of the well bore and the related fractured area.

We agree the submittal of a NDIA is essential but the PNDI that is required by PA is not acceptable, as discussed in this Comment on Section 7.5.e.2.ii.

This section also needs to be very clear that approval of a NGDP plan does not give an irrevocable right to use of the pad. It should be made clear that the approval can be modified or revoked at any time by the Commission for any reason, including because of bad acts by leaseholders, the infiltration of other wells and projects that have changed the dynamics in the watershed in a way that warrants it, changed regulatory controls by any entity with jurisdiction, or because of other changing conditions in the basin such as global climate change, cumulative drilling impacts, or other anticipated, known or unknown future changing conditions.

Section 7.5(e) Approval by Rule (ABR). We oppose ABR for gas well pads. By allowing gas well pads to move ahead without a NGDP, any opportunity for applying any planning or effort to reduce cumulative impacts, however slight that possibility may be, is removed completely. This allows well pads to move ahead in an unplanned manner, imposing the “death of a thousand cuts” threat since these pads can each carry many wells and can reasonably be expected to have substantial impacts, as discussed by Harvey above.

Adams also questions how the well pads that receive an ABR under the criteria listed for well pads that do not conform to a NGDP will differ in terms of development constraints from wells that are covered by a NGDP. This is unclear and poses a problem that could be exploited by project sponsors. Adams states (Adams p. 17):

A project sponsor can apply for a well pad APR if it has an approved NGDP, or if it meets specific siting requirements. These requirements are improvements over state well pad requirements, i.e., the well pad cannot be located on slopes greater than 15%, it cannot be located within the New York City Reservoir drainage basins, and the well pad cannot be located on a forested site (although the forested site definition is weak and unclear as discussed earlier). It is unclear how these “more stringent” requirements will apply to APRs for wells under an approved NGDP, presumably the Commission will rely on the NGDP mapping to make these determinations for compliance. The required scale of mapping (at a 7.5 minute quad scale of 1:2000) is insufficient to provide adequate mapping information to determine project compliance.

The use of an ABR for gas well pads assumes that by meeting the limited criteria listed, the impact will not be substantial. This is an incorrect assumption. While the criteria do impose some standards that

exceed host state requirements, the criteria leaves much open to interpretation because of lack of clear definitions and specific measurement tools. For instance, as discussed under Section 7.2 Definitions, a forested site is not adequately defined; there is no discussion of quality, and no metrics describing the forest. The 15% slope is not defined over a distance; we do not agree 15% is adequate protection as discussed in these Comments under Section 7.5.b.3.ii (industrial uses should only occur with “great care” on 15% slopes according to Table 1). While it is appropriate that ABR not be allowed in National Park Service management areas or watersheds that drain to New York City’s reservoirs, what about other water supply reservoirs and the Delaware River itself, a water supply for over 15 million people? The criteria seem arbitrary and not well developed.

Section 7.5(f) Well pads added to an approved NGDP. We oppose an ABR for adding pads to an approved NGDP. This defeats the purpose of the NGDP. As stated earlier, the plan should cover a total “build out” scenario, not be allowed to be added to piecemeal without reworking the Plan. This is a classic “loophole” that will be exploited to the detriment of the water resources of the basin. We also oppose the decision regarding an ABR under these circumstances being held by Executive Director with no public input process.

Section 7.5(h) Well pad requirements. These requirements apply to pads for high volume hydraulically fractured wells and well pads for exploratory wells or low volume hydraulically fractured wells.

Section 7.5(h)(1) Applicable Requirements for all Well Pads.

Section 7.5(h)(1)(i) Planning Requirements. For wells that meet the requirements for a NGDP, a Lease Area Map must be submitted. Five well pads can be installed prior to the requirement for a NGDP. A NGDP must be submitted and approved prior to development of the sixth well pad in the basin. Once the NGDP is approved, ABR can be used to approve well pads for exploratory or low volume hydraulically fractured wells within the boundaries of the NGDP but not included in the original approval of the NGDP. We oppose the use of ABR for exploratory and low volume hydraulically fractured wells because these can have substantial impacts on the water resources of the basin, as explained within this Comment and in the expert reports submitted for the DRBC Administrative Hearing. The Commission continues to not recognize the impacts that these wells have, despite the experts the Commission itself engaged themselves whose testimony in expert reports verifies the adverse impacts of exploratory wells.

Section 7.5(h)(1)(iii) Water Source Requirements. (A) and (B) Proposed Sources. We agree that the Commission must approve the water sources used by a project sponsor. We do not agree that the water sources listed are acceptable as discussed in this Comment in Section 7.4; we also discussed the reporting and recording (Section 7.5(h)(1)(iii)(C) and (D)) requirements. In addition, all water reporting and recording should be tracked using a web-based real-time tracking system similar to what the U.S. Postal Service uses to track packages in the office and in the field. Truck operators would be equipped with input devices and upon entry, agencies would have data available real time. Automatic alerts and

notifications would be built into the system. This automated system is needed to ensure SPWs are protected based on the projected consumptive use from the operators large-scale.

Section 7.5(h)(1)(iii)(E) Water supply charge. We agree that the water use for natural gas is 100% consumptive. Adams points out (page 18-19):

With regards to water sources, the requirements fall short of providing for adequate resource protection as discussed previously in detail (regarding Section 7.4). One item worth noting is that for the purposes of payment, the holder of a well pad approval is required to pay the Commission's water supply charge for consumptive use by assuming that "100% of the water used by a natural gas extraction and development project is considered to be consumptive for the purpose of calculating the water supply charge". If the Commission is regarding water use as 100% consumptive for the purposes of fee collection, than this water must also be considered 100% consumptive for the purpose of water withdrawal or transfer (as discussed previously) and it is essential that the Commission consider the cumulative impacts of this water loss on a watershed basis, as well as the local impacts on headwaters and wetlands.

Demicco asks (Demicco p. 8):

One question that should be considered is the 100 percent consumptive use requirement for the water supply charge. In fact, water use by gas fracturing can be much more than 100 percent consumptive if additional water is needed to dilute the brines down from their high chloride and other chemical component concentrations for specific discharges. Brine total dissolved solid concentrations are in the order of 150,000 mg/l, almost 5 times the concentration of sea water and almost 1000 times the concentration of shallow aquifer-zone ground water and surface waters.

Recommendation: The consumptive use fee should be based strictly on the treatment and discharge option proposed for the individual well pad application and the location of the discharge within or outside of the Basin For example, any saline discharge within fresh waters of the Delaware River Basin without treatment for total dissolved solids should be charged a 1000 time surcharge on the volume of water used. This would effectively discourage discharge to Public Owned Treatment Plants which do not treat the total dissolved solids of the discharge other than dilution and will provide incentive for pretreatment of salinity before wastewater removal to a treatment facility.

We agree with Demicco's recommendation. The loss of this fresh water would deplete the Basin's resources and the economic impacts would be large; project sponsors should bear the costs, not the public. This recommendation is a step towards requiring some participation from the industry for the losses that the Basin would suffer.

Section 7.5(h)(1)(iii)(F) Water Conservation. We agree water conservation is crucial. We do not agree that reuse of wastewaters is a way to do that. In fact, the potential for pollution by the reuse of flowback and production waters as proposed (no water quality standards that would remove all hazardous

substances) makes the opposite effect likely—that ground and surface waters will be polluted by this reuse, reducing the amount of clean water available for existing uses and the environment in the basin.

Section 7.5(h)(1)(iv) Wastewater.

Section 7.5(h)(1)(iv)(A) Disposal.

Section 7.5(h)(1)(iv)(A)(1) and Section 7.5(h)(1)(iv)(A)(5). We agree that disposal of gas drilling wastewater should only go to approved facilities. Will the Commission evaluate the ability of the approved facilities to process and remove all pollutants? We advocate that gas drilling waste fluids cannot be discharged to groundwater or surface water; the Draft Rules should require that all gas drilling wastewaters be processed so that pollutants are removed and no effluent is discharged unless it is nontoxic and free of contamination. Domestic, non-domestic wastewater, unused water, recovered flowback and production water, combination of recovered flowback or production water and fresh waters or fluids approved for use at the well pad should not be discharged to groundwater or surface waters of the Delaware River Basin. We oppose the approval of the discharge of these waters to ground and surface water under current regulations. The Commission should develop a zero discharge gas drilling wastewater policy in keeping with its policy in the Water Code of no discharge to SPW in order to avoid release into the environment of the toxic wastewater that is produced.

Due to the issues and science available and evolving on wastewater and flowback from gas wells, DRBC should prohibit any disposal or discharge of treated or untreated wastewater/produced water to a facility that discharges treated water to streams or any water body, wetland, underground storage, underground aquifer, mine pool or land mass within the Delaware River Basin. As discussed in Parasiewicz, the tools and scientific foundation for the current decision-making and management process are still too inadequate to assure the protection of keystone species of the Upper Delaware River to allow any discharges in the Basin (Parasiewicz, p. 2)

Miller states the issue of “treatment” is not well defined in the regulations. This waste, which is highly radioactive and saline in nature after treatment, leaves behind residual concentrates which need to be disposed of somewhere. In addition, Miller states the radioactivity is challenging since “treatment” to remove radioactive components will result in more concentrated (but lower volume) waste with a higher proportion of radioactivity. The radioactive elements do not “go away”, but are simply concentrated in some other form if removed from the produced water. How does the Commission plan to address radioactivity in wastewater and in solids?

Miller states Naturally Occurring Radioactive Materials (NORM) are either not regulated or poorly regulated, and proposals have emerged to allow discharge of this saline and radioactive water directly into a saline environment. The data on the toxicity of radioactive materials to marine and estuarine ecosystems are scant, and the Commission should prohibit any discharge of produced water into any estuarine systems, due to this issue. (Miller p.3)

Harvey states a zero discharge policy for both liquids and solids is a Best Management Practice that the Commission should adopt. (Harvey p. 21) The Commission should have its own regulations and enforcement personnel in place and should not rely on antiquated and inadequate state standards of NY. To rely on the state will not protect the Delaware River Watershed. Bishop's review of New York's current regulatory framework and enforcement staff that covers the oil and gas program concludes it is inadequate to protect the water resource of the Delaware River Basin from gas drilling. (Bishop p. 9-13)

Bishop goes on to describe major problems with the various NY regulations involving natural gas and wastewater that are outlined specifically in his report. For example, NY code for solid waste exempts waste from oil and gas from being hazardous substances. Bishop states NY laws and regulations for the handling of natural gas development waste are diffuse (spread over multiple sections of law), regulations and guidance documents, incomplete (lacking even a definition or group of definitions for this waste) and incoherent: in some sections suggesting that this waste is polluting and potentially hazardous, and in others exempting it from being declared hazardous. Bishop goes on to state it is difficult to envision a concise, complete and coherent regime of oil and gas regulations ever being developed in New York without extensive revision of state environmental law. Overall, the Draft Rules exert greater compliance process control than New York's regulations in every aspect except for ground transportation. (Bishop p. 9-13)

Bishop cites various problems with NY's staff and enforcement arm for Oil & Gas. New York's Bureau of Oil and Gas Regulation currently has only 16 field agents, so with over 13,000 oil and gas wells to monitor, the typical agent is responsible for more than 800 wells. (Bishop p. 13) The Commission should assist with an enforcement arm and have its own staff responsible for aspects of enforcement to ensure the Delaware Basin is protected. How many staff members does the Commission envision adding to its own program to watch-dog the industry? How does the Commission plan to address the cumulative impact of the large amounts of wastewater projected from gas development?

A cumulative analysis needs to be conducted before considering any discharges of treated wastewater in the Basin or beyond. Oil and gas wells produce about 9 million gallons of wastewater a day in Pennsylvania, according to industry estimates used by the PADEP. By 2011 that figure is expected to rise to at least 19 million gallons, enough to fill almost 29 Olympic-sized swimming pools every day. That's more than all the state's waterways, combined, can safely absorb, PADEP officials say. "I don't know that even our [water] program people had any idea about the volumes of water that would be used," said Dana Aunkst, who heads the PADEP's water program⁵¹. How can the Commission rely on inadequate regulations set up by the states to protect the Delaware River Basin? How can the Commission rely on the state agencies, with booming drilling rates and not enough staff, to begin enforcing regulations and permitting in the Delaware River Basin to adequately protect the Basin? The Commission needs to have its own program for tracking and accounting for drilling wastewater from cradle to grave and cannot rely on the states to do this. The Commission needs to develop its own

permitting force to ensure the Basin is protected. Enforcement issues are also addressed in this Comment under 7.3(n).

How can the Commission include permitting for discharges in the regulations when the required plants do not exist in the host states to adequately treat the waste? Both sewage treatment plants and industrial plants designed just to treat drilling wastewater are grossly inadequate at treatment⁵². See **Attachment 6** “Containment Characterization of Effluent from PA Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, PA: Implications for Disposal of Oil and Gas Flowback Fluids from Brine Treatment Plants” March 25, 2011, Volz et al.

The Draft Rules should not allow existing plants to take wastewater from drilling and there should be a zero pollution discharge policy as part of the regulations for drillers wanting to operate in the Basin. The Commission should require a study funded by the industry to determine the fate of wastewater that remains beneath the earth that does not come back up as flowback. PADEP estimates that about 87% of the water used to frack remains in the deep shale formation. How does the Commission account for the depletive use of this industry and what is the Commission’s rationale for permitting this industry with such an intensive need for freshwater that is removed from the hydrologic cycle?

EPA warns against using sewage treatment plants to dispose of drilling wastewater, because the plants aren’t equipped to remove TDS or any of the chemicals the wastewater may contain. TDS can also disrupt the plants’ treatment of ordinary sewage, including human waste. Scientific American reports, no plant in Pennsylvania has the technology to remove TDS, and it’s unlikely that new plants capable of doing so can be built by 2011. The company whose bid is furthest along in the permitting process says its treatment plant won’t be ready until at least 2013. And at its peak that plant would be able to treat only 400,000 gallons of wastewater a day. PADEP would need 50 plants that size to process all the wastewater expected by 2011⁵³. How does the Commission reconcile the action of allowing drilling when wastewater “treatment” is so unknown and when treatment options available are not in existence? How does the Commission plan for the projections and ramping up of drilling to adequately dispose of wastewater from 16,000 to 30,000 (or more) gas wells projected for the Delaware River Basin? The Commission should not allow gas development until the issues of wastewater have been thoroughly investigated and resolved and until technology allows for a zero pollution discharge policy.

In the meantime, PADEP is allowing municipal sewage plants to continue taking drilling wastewater, even though none of them can remove TDS. "That’s not what these municipal plants are designed to handle – PADEP is inviting legal problems as well as environmental problems," said Bruce Baizel, a senior attorney for the Oil and Gas Accountability Project, a Colorado-based nonprofit that focuses on the environmental impact of natural gas drilling.⁵⁴ Isn’t the Commission inviting similar legal problems if it began allowing discharges of wastewater in the Basin with inadequate treatment?

How do the Draft Rules account for the air impacts associated with trucking heavy wastewater from pad sites to “treatment” locations? How do the Draft Rules account for air impacts that are generated from

the treatment of wastewater at treatment plants? Has the Commission performed an analysis of the cumulative impact of these air impacts that include the treatment of wastewater? Since air pollution can affect water, it is critical the Commission considers this and regulates air pollution impacts.

According to the Volz⁵⁵ study, brine water has high levels of hazardous chemicals to aquatic life and human health that are not treated properly in the wastewater process.⁵⁶ Therefore, wastewater discharge to water bodies in this way should not be allowed anywhere, even outside of the Basin.

Furthermore, the effects of these chemicals and the synergistic effects between them or when introduced to other constituents in the water or a downstream treatment source are not well understood or known. PADEP has not addressed the many issues associated with wastewater so relying on “approved” wastewater facilities by PADEP outside of the Basin is not protective of aquatic life or human health and does not fill the Commission’s role of doing no harm.

The discharge analysis conducted at the Josephine Facility by University of Pittsburgh shows high levels for contaminants including: barium levels in discharge water was 14 times the US EPA MCL of Ba for drinking water of 2ppm; for aquatic life protection barium levels exceeded the EPA maximum concentration for protection of aquatic health by 1.3 and the EPA continuous concentration to protect aquatic health by 6.7. Levels of bromide were detected at the Josephine discharge at 10,688 times the 100 ppb level that raises concern in freshwater sources.

Bromides in freshwater, when mixed with disinfection treatment processes for drinking water, form trihalomethanes and other chloro-bromo byproducts that are hazardous to human health. This is a serious problem for water suppliers that use chlorine (most all do, including Philadelphia) because the produced byproducts then have to be controlled according to water supply treatment standards, which is expensive and difficult. PADEP acknowledges in its Chapter 95 High-TDS rulemaking that bromide is a key parameter of concern in the effluent because it can form brominated disinfection by-products (DBP’s) in water supplies. These are a drinking water hazard because of the propensity for the brominated DBP’s to “increase[s] overall DBP concentrations, specifically trihalomethanes (THMs)”, which can cause cancer.⁵⁷ Yet bromide was not included in PADEP’s Chapter 95 rulemaking and is not included in the Draft Rules. DRBC should include bromide as a constituent in wastewater that must be regulated.

Chloride levels at the Josephine Facility discharge were 138 times the EPA criteria maximum concentration (CMC) and 511 times the EPA criteria continuous concentration (CCC) to protect aquatic life. Other gross exceedances were found for other constituents (but not limited to): strontium, benzene, manganese, 2-butoxyethanol, and total dissolved solids⁵⁸.

Has the Commission compared constituents in the wastewater with the list of water quality standards to ensure all standards are adequate and regulated? How does the Commission plan to determine, monitor,

and regulate the synergistic effects of all of the drilling wastewater chemicals with naturally occurring constituents from the deep shale and other constituents that may be in river water? It is unclear in the regulations how this can be achieved.

How does the Commission plan to deal with cumulative impact of the wastewater generated? According to PADEP, “Estimates from the industry indicate that demand for brine water treatment in Pennsylvania will reach approximately nine million gallons per day (MGD) in 2009, 16 MGD in 2010, and 19 MGD in 2011. Estimates from the Susquehanna River Basin Commission are 20 MGD for that same timeframe⁵⁹.” Considering these large numbers and the potential for adverse impact on the streams and rivers of the State, drilling permits should be paused until best technology treatment facilities are in place, tested and proven to be sufficient to remove dangerous pollutants and until PADEP adopts protective discharge and water quality standards that include all constituents in the drilling wastewater. The Monongahela River and TDS issues found there from drilling wastewater, for example, illustrate the reality of this big concern.⁶⁰

TDS criteria may not be protective of aquatic life and therefore discharges of treated wastewater should not be allowed in the Basin. Pennsylvania revised TDS requirements and criteria that closely match the 500 mg/L criteria recommended by the USEPA (PA Bulletin 2010). Currently the Commission regulations include a TDS water quality standard of 500 mg/L basin-wide, and also provide for a maximum increase in TDS of 33% over background by any proposed discharge (or group of discharges) as a means of minimizing effects on aquatic biota and keeping TDS at the more dilute levels seen through much of the basin (DRBC 2008a).

Both the existing water quality defined by Special Protection Waters regulations and recent unpublished data (DRBC 2006-2009) indicate that TDS in Special Protection Waters streams and rivers typically ranges between 50 mg/L and 100 mg/L, five-to-ten times below the common 500 mg/L TDS criteria (DRBC 2008a, DRBC *unpublished data*). Thus, the Delaware River and its Special Protection Waters tributaries currently maintain concentrations of dissolved solids (including salts and other compounds) far below EPA-recommended criteria⁶¹. More appropriate TDS criteria and other drilling contaminants of concern for different regions of the Basin to protect aquatic life in different areas need to be developed by the Commission. The Commission needs to consider the assimilative capacity of larger rivers and what effects high TDS in these rivers (even without drilling wastewater) already has on aquatic life. High total dissolved solids concentrations and fluctuations of these salts are toxic to aquatic life that use osmoregulation to maintain their balance of water and ions to survive⁶².

The Draft Rules must outline what “treatment” procedures are involved with the treatment of wastewater and require a zero discharge policy. Solid waste from the treatment process also needs to be highly regulated by the Commission since it contains radioactive materials. Existing plants cannot adequately treat the dangerous chemicals in the water. So stream discharges are not appropriate for the Delaware River Watershed.

According to EPA, based on the levels of radioactivity in drilling wastewater, Mr. Azzam, EPA identifies a need for a program to protect workers, the public and the environment from exposure to radioactivity. Earlier in the memo he says that any state programs should be at least as stringent as federal law would require. This is important because, as Mr. Azzam points out, the E.P.A. may have limited authority to impose these regulatory requirements alone⁶³. How can DRBC consider allowing drilling that will produce this wastewater with radioactive constituents when adequate regulations are not yet in place to deal with it? How does DRBC plan to address the cumulative effects and volatilization or evaporation of radioactive water or radon gas? Radon has a half life of 4.5 billion years; its release during well stimulation and/or extraction must be addressed.

A study by the American Petroleum Institute in 1990 found a potential increased risk of cancer among people who often eat fish from waters where drilling waste is discharged. The study applies to DRBC since state regulators in Pennsylvania have said that dilution is effectively removing the risks posed by drilling waste that is discharged into rivers. This study found an increased risk of cancer when drilling waste was dumped into a larger body of water than Pennsylvania rivers (Gulf Coast). Furthermore, state records indicate that radium levels found in Pennsylvania wastewater are much higher than those used in the 1990 study. Radium, for example, was found in Pennsylvania at levels over 18 times the number used in the 1990 study. In an e-mail exchange with The Times, Anne F. Meinhold, one of the lead authors of the study, wrote, "I suspect that the dilution rates in a river would not be as high as for the open water discharges we considered." Asked to review the study, an expert on human health and ecological risk analysis said that it clearly shows that the drilling waste is not sufficiently diluted in some cases. As a result, the radioactivity levels left behind in receiving waters come close to reaching the threshold at which the E.P.A., under federal Superfund rules, requires a cleanup, the risk expert said.⁶⁴ Bioaccumulation in fish tissue was also part of this study with ingestion being a route for exposure. How does DRBC plan to address the human health concerns and aquatic life health concerns of the discharge of drilling wastewater which has an abundance of different chemicals present in it? How does DRBC plan to deal with bioaccumulation factors for chemicals in drilling wastewater? Delaware River fish, in many sections of the River, already have human consumption warnings. How can DRBC propose to include more toxins that could make fish more toxic for humans to eat?

EPA conducted modeling in a few rivers to determine the fate of radioactivity and in the model, the rivers were not able to dilute radioactive material to an acceptable level⁶⁵. The Commission should develop a similar model for the Delaware River Basin. The model would have to show projections over time as the drilling scenario would ramp up and increase over time. This model would have to include the fate of many of the chemicals that have risk associated with them and the chemicals that could be formed synergistically over time and mixing. This analysis should be conducted before moving forward with regulations to inform the process based on the results.

With tens of thousands of pounds of 300 plus proprietary chemicals, biocides, surfactants, organic

compounds, scale inhibitors, etc used in the hydraulic fracturing process, how does the Commission plan to regulate all of the constituents found in the wastewater to protect aquatic life and community health?

How does the Commission account for water usage for “treatment” of wastewater? What is the water requirement and energy needed for tertiary treatment using reverse osmosis? For example, how much water is wasted in this process of tertiary treatment?

EPA notes tertiary treatment (e.g. reverse osmosis and evaporation/crystallization methods) may be needed to adequately treat the waste for both public sewage treatment plants and commercial industrial wastewater treatment plants. This process itself has its own dilemma as it produces other types of super-concentrated waste that will require disposal⁶⁶. EPA further recommended against approving disposal of wastewater through conventional wastewater treatment until a review of chemistry of the flowback and water quality standards and criteria are developed for numeric permit limits for all pollutants of concern not substantially removed by conventional treatment. How do the Draft Rules reconcile including wastewater discharges with this information? The Commission has not established numeric limits for all of the gas drilling wastewater constituents. The Commission should establish these limits and do the necessary studies to determine safe thresholds before finalizing the regulations. Numeric permit limits also must account for the projected and increasing discharges expected over time to account for cumulative impact of this waste.

EPA has concerns of downstream drinking water intakes below wastewater treatment facilities as outlined in a memo about further study indicating, “include risks to surface drinking water intakes from conventional treatment discharges where constituents are not yet identified or limited by NPDES requirements. Region 3 will be conducting radionuclide fate and transport study that could help inform this effort⁶⁷. How can the Commission move forward with proposed regulations before this EPA study on radionuclides is conducted? The Commission should wait for this study to inform its regulations.

How do the Draft Rules address the quantities of wastewater (once freshwater) that remain underground and are not brought back up as flow back water? This water is removed from the hydrologic cycle – therefore it is a depletive use of freshwater.

How do the Draft Rules regulations address the quantities of salt cake that will need to be disposed of in landfills? EPA questions if there is enough landfill space to hold all the cuttings and salt cake needing disposal from the industry. The Commission should not allow any land disposal of these materials in the Delaware Watershed due to the hazardous and super-concentrated nature of this waste which often contains radioactive materials⁶⁸. The Commission should also not allow any burial of drilling cuttings and other waste products associated with drilling on-site.

Toxicity tests should investigate the effects on stream benthics like mayflies that are used as the indicator of toxicity rather than typical laboratory indicators traditionally used. For example, EPA says

mayflies are extremely sensitive to TDS fluctuations. More research needs to be done on this topic by the Commission to ensure aquatic life is protected and not allowed to decline.

The interim policy of PADEP, which is permitting new plants with effluent standards well in excess of those being proposed, is damaging our streams, rivers and water supplies. PADEP states that "...many of the rivers and streams of Pennsylvania have a very limited ability to assimilate additional TDS, sulfates and chlorides because of elevated levels from historic practices"⁶⁹. Yet PADEP further says that there is no adequate cost effective solution to treat the brine and that dilution of waste is necessary since treatment does not remove many of the wastewater chemicals and discharges should be directed and trucked to larger rivers.⁷⁰

In a conference call as early as October 21, 2008, PADEP officials recognized the problem of radioactive materials and high TDS being discharged from ineffective treatment and requested EPA to help with pre-treatment guidance. The New York Times reported tests conducted in 2009 and 2010 by the publicly owned sewage treatment plant in McKeesport, Pa., to state regulators showed that Chesapeake Energy wastewater processed by the plant carried gross alpha radioactivity levels that in some cases were over 30,000 pCi/L, or more than 2,122 times the level that the E.P.A. considers acceptable in drinking water⁷¹. How can DRBC defer to state regulations that are inadequate and not protective of the resource? How can the Commission defer to "treatment" options that harm aquatic life and are not regulated properly? Though this was untreated flowback water readings, how are these high numbers considered for a cumulative impact with various discharges of wastewater? The Commission should model this scenario before moving forward with regulations.

The Clean Water Act forbids sending waste to a treatment plant if that waste causes problems with the plant's ability to treat water (as it affects microbes). Wastewater from the oil and gas industry can cause problems for sewage treatment plants, leading them to violate their discharge permits⁷². This point was identified by regulators well in advance but DEP continued to allow discharges. Months after this discussion, the New York Times reported, the Pennsylvania Department of Environmental Protection issued a fine of \$75,000 to one treatment plant, and ordered it to stop accepting drilling waste after it discharged fecal coliform and suspended solids into a river⁷³. How can DRBC include regulations where wastewater would be allowed to be taken to these plants? How can DRBC defer to inadequate state oversight and regulations?

A Pennsylvania field survey of Tenmile Creek indicates that inadequately treated discharge from a STP accepting waste is causing harm to aquatic life⁷⁴. A letter from West Virginia to Clarksburg Sanitary Board, also cited in the NY Times, shows ineffective POTW treatment of gas drilling waste and negative effects on the plant from the waste⁷⁵. How can the Commission include regulations where wastewater would be allowed to be taken to these plants that are not effective treatment options?

An impact study conducted by NY suggested caution in permitting extensive hydrofracturing activity and NYC has requested that the watersheds to its reservoirs be excluded from natural gas drilling⁷⁶. The Commission needs to consider this report and the information provided while looking at the implications for large scale wastewater inputs and infrastructure changes from forest and rural to industrial use in the remaining part of the watershed – a watershed that supplies over 15 million people with drinking water.

Truck traffic to transport wastewater puts communities and nearby streams and habitats in harm's way if there is an accident. This water is then lost to the Basin and is transferred to another Basin. This type of basin transfer of wastewater (or freshwater for fracking) can also introduce harmful invasive species between basins.⁷⁷ It also accounts for even more depletive use of the Watershed. In addition to wastewater, drill cuttings and drilling fluids also need strict regulation and should not be discharged or buried anywhere in the Watershed.

Harvey recommends the Draft Rules include drill cuttings and drill fluid waste handling requirements for all drill cuttings and fluids from the entire well, not just select intervals. She also recommends special handling and treatment and disposal requirements for NORMs, mercury, cadmium, and other heavy metals. (Harvey p. 21)

Harvey's other recommendations include eliminating waste disposal waivers at Sections 7.5(h)(1)(iv)(A)(5) and 7.1(e)(4) that allow waste to be discharged into the Delaware River Basin. We support these recommendations.

Drill cuttings and fluids should be fully regulated by the Draft Rules and sampled, tracked and monitored under the same requirements whether from high volume hydraulically fractured wells or not. (Bishop p.3) The Draft Rules should include drill cutting and drill fluid waste handling requirements for all drill cuttings and fluids from the entire well, not just select intervals.

The Draft Rules should include special handling, treatment, and disposal requirements for drilling waste and equipment that contains Naturally Occurring Radioactive Material (NORM), mercury, cadmium, and/or other heavy metals.

Section 7.5(h)(1)(iv)(A)(2) Contractual Agreement. In addition to specifying the proposed disposal facility, the well pad project sponsor must provide the quantities of wastewater and the tracking from source to disposal – monitoring at each stage is critical to ensure proper account of wastewater from cradle to grave. Enforcement of this process and inspections are also needed. This enforcement and inspection needs to be taken on by DRBC and not the state agency that is already strapped with a rampant drilling rate, particularly in PA. How many DRBC inspectors will be hired to oversee drilling in the Basin? How can DRBC regulations provide more oversight by incorporating the county conservation districts into the regulations? Local enforcement agents should be within close proximity to the drilling in order to respond and inspect rigorously.

Section 7.5(h)(1)(iv)(A)(3) Reuse. We oppose the reuse and reinjection of wastewater as discussed in this Comment under Section 7.4. Miller states this reuse of water will lead to generally higher levels of contaminated water being injected and could also lead to pollution events to groundwater, land, and surface water. (Miller p. 3) Best available technology for leak detection systems that could detect a leak quickly should be required.

Section 7.5(h)(1)(iv)(A)(4) No road or land surface application of wastewaters. We support the prohibition of the application of flowback or production water and brines on any road or other surface and this prohibition is more protective than host states. But this wastewater should also not be allowed to be applied on land outside of the Basin due to concerns about the chemicals found in the wastewater. Wastewaters produced here in the Delaware River Basin should be processed here to remove all pollutants.

Section 7.5(h)(1)(iv)(B) Recording and Section 7.5(h)(1)(iv)(C) Reporting. We support the recording of volume of wastewater produced at a well site. We support continuous monitoring through modern state of the art technology, as discussed elsewhere in this Comment. Wastewater quantities, volumes, and weights must be monitored electronically and by log from cradle to grave and as specified in the proposed regulation but DRBC must go further. In addition, it is critical that the wastewater at each well pad site, before leaving the site, needs to be analyzed for constituents of concern since different well pads may generate different wastewater analytes (New York SGEIS). As indicated by Glenn Miller, since produced water is highly saline and radioactive with hundreds of contaminants, there needs to be specific measurements of the wastewater/produced water in place as it appears this is lacking from the regulations. (Miller p. 1)

MSDS sheets, a full disclosure of chemicals, and a plan for emergency clean up must accompany the wastewater on its way to disposal by truck so emergency response personnel and inspectors can access this information easily in case of emergency and/or for routine inspections. An electronic real-time cloud-based database and tracking system with scanners (similar to what US Postal Service uses that tracks packages) must be developed and paid for by the drillers to account for this waste from cradle to grave and to track wastewater via electronically as well as by hand and in logs.

The electronic tracking should be available to the Commission and to the public in real time and checks should be put in place to automatically flag if a truck or delivery that was expected at a wastewater plant did not arrive in the specified time expected to alert officials of a missing delivery. In this way, there would be better policing of tremendous amounts of waste being carted by truck from cradle to grave.

From a review of DEP pollution incidents from oil and gas operations from January 1, 2007 to Sept 30, 2010, there were 306 incidents where wastewater was spilled.⁷⁸ This oversight is needed as indicated by FrackNet. A two day enforcement effort by multi-agencies last year that targeted wastewater flowback trucks in PA found many trucks out of compliance with safety hazards. 131 trucks were put of service

during the sting operation. According to Noonan, 731 commercial trucks were inspected March 14-15 during “Operation FracNET.” Fourteen drivers were placed out of service and state troopers issued 421 traffic citations and 824 written warnings. In addition, DEP personnel issued 35 citations and 13 written warnings.⁷⁹ The issue of transportation of these hazardous chemicals must also involve proper oversight and regular inspections. This electronic tracking system would be mandatory and required in the regulations and the drillers would pay for this system.

The “DRBC Post Hydraulic Fracturing Report” to the Commission must be made available on a shorter timeframe than 60 days. And the electronic system would make data available real-time to the Commission to better track volumes of flowback and production waters. The report should be made public and posted on the Commission website.

A weight station should be required in the Draft Rules and funded by the drillers for trucks in order to independently check weights of cargo to compare volumes from cradle to grave to ensure no dumping has occurred. This weight station input would also be part of the electronic tracking system.

The Draft Rules should require wastewater trucks to have high profile safety placards and coding on each truck (able to be viewed from a distance with the naked eye) carrying wastewater within the Basin so the public and officials can identify these trucks from a distance. An entirely different colored truck with a placard would be an even clearer way to identify a wastewater truck from a freshwater truck. Trucks that carry flowback water should not be allowed to carry freshwater without changing placard so the public and officials clearly can identify the different cargo being transported. This will help avoid false alarms by the public witnessing trucks at water withdrawal stations who they believe may be illegally discharging gas drilling water for example.

Section 7.5(h)(1)(v) Nonpoint source pollution control plan. (NPSPCP) We support the requirement for the development of a NPSPCP and we suggest improvements as discussed elsewhere in this Comment. Due to the potential for substantial nonpoint source pollution from natural gas development, the requirement for these plans should apply to Basin waters located outside of Special Protection Waters. Also, the host state regulations in PA and NY are not adequate. While this section requires a description of final site conditions and a project hydrograph analysis, which is more than the host states require, it is unclear what the Commission will do with this information. Further, the use of an ABR will allow projects to escape the NPSPCP and lead to degradation of the water resources of the basin. As discussed by Adams (Adams, p. 19):

Well pads are only required to prepare a Non-Point Source Pollution Control Plan only if the well pad is located in the portion of the Basin classified as Special Protection Waters. A Plan is not required for all other waters, and as previously discussed (regarding water sources) the existing regulations in Pennsylvania are not adequate to protect the resource in either Special Protection or other waters. Most importantly, the Commission will rely solely on the state requirements for erosion & sediment control and stormwater

management for all well pads approved by APR for exploratory or low volume purposes. Therefore, it can be anticipated that most well pads will seek compliance under the inadequate state regulations, even in Special Protection Waters.

Section 7.5(h)(1)(vi) Mitigation, Remediation, and Restoration. As discussed elsewhere in this Comment, the reporting of incidents is appropriate but insufficient. The stoppage of activity is important but it is not clear who will enforce this and under what criteria. Also, notification of potentially impacted users of water should be part of a wide public notification system as was discussed earlier in this Comment. We oppose the provision that allows the closure and restoration of a well site to be left to host state requirements which are totally inadequate and do not require the restoration of original conditions. In other words, degradation of the land surface is allowed. Land activities impact water resources as discussed elsewhere in this Comment and as recognized by the Commission in the Water Resources Plan and other Commission documents. This means that the watershed will inevitably be degraded. Adams states (Adams p. 19-20):

Similarly, for mitigation, remediation, and restoration, the draft regulations accept the host state requirements as adequate for closing and restoration of a well pad site. As discussed in Attachment 1, Pennsylvania's requirements are minimal and consist primarily of seeding the site with a seed mixture that contains some seed material for "brush" species. The Commission should develop its own requirements for site restoration, and a plan to achieve the restoration should be included as part of the well pad application and approval process for all well pads. This restoration should include a process for demonstration of compliance within a set time period. Financial assurance (as addressed in Section 7.3.k.15) should be maintained until adequate site restoration has been demonstrated (and not simply for one year where "no harm" has occurred).

Also, as previously discussed, the definition of an "adversely affected" well or surface water users (as a result of releases) is not well defined and open to interpretation. Specific parameters related to water quality and quantity should be defined by the Commission for guidance regarding "adverse effects" to provide a benchmark. The report of an investigation or mitigation plan should be prepared by an independent qualified professional as directed by the Commission, with professional fees for the professional paid through the Commission to assure an independent and unbiased review. This is standard practices for other construction projects and installations, and would assure that professional recommendations are unbiased.

Section 7.5(h)(2) Additional Requirements for all Well Pads involving High Volume Hydraulically Fractured Wells.

Section 7.5(h)(2)(i) Groundwater and Surface Water Monitoring.

Section 7.5(h)(2)(i)(A) Pre-alteration Report.

First, it is unclear if "pre-alteration" refers to before well pad construction or before fracturing. Adams points out (Adams p. 20):

For the pre-alteration monitoring of surface waters, samples should be collected prior to the construction of the well pad to assure adequate representation of pre-alteration. The draft regulations do not indicate whether “pre-alteration” refers to before well pad construction or before fracturing. Since many exploratory wells may be converted to high volume hydraulically fractured wells, and since the construction of all well pads can adversely affect surface water quality, this requirement should be clarified to apply to all well pads, with pre-alteration defined as pre-construction. Again, all sampling results should be available for public access.

Section 7.5(h)(2)(i)(A)(1). The Draft Rules’ recommendation for a pre-alteration report is not sufficient to provide the needed information. As discussed in these Comments under Section 7.4, aquifer testing is required in order to locate existing water wells and other artificial penetrations and to map existing fractures and pathways that gas or fluids could move through in order to assess the potential for contamination of ground or surface water as a result of hydraulic fracturing. Demicco explains that the site’s geologic conditions and depths to the available water wells to be tested must be considered, including the depths to which water wells have been completed. It is recommended that at least one moderately deep monitoring well be installed and monitored in perpetuity. Demicco states (Demicco p. 16-17):

At least one moderately deep (300 foot) properly cased rock well must be available for permanent monitoring before, during and after fracing, preferably within 1,000 feet of the well being fraced.

The draft regulations fail to establish adequate monitoring requirements for water levels, before, during, and after fracing. Recording water level transducers are accurate enough to register responses up to a few hundredths of a foot. Any change in pressure in the rock mass above a fraced zone will be observed as a water level change within the overlying rock mass. If pressure escapes into the well bore annulus, a response in water levels certainly could be observed in a moderately deep rock water supply well. This is based on personal observation of low pressure water supply fracing where measurable responses were observed in wells 1,000 feet away from the pressurized well where only several thousand psi were applied, not the 15,000 psi or more used in deep well fracing.

Recommendation: Water level pressure monitoring must be included within the regulations in the deepest available rock well within 1,000 feet of the gas well being fraced during the part of the pre and post development well testing. Monitoring farther outwards from the fraced area is also recommended based on bedrock geologic conditions.

Adams (p. 20) and Harvey (p. 19) point out the Commission provides no justification for the proposed ground and surface water monitoring distances and these must be scientifically justified. While the Draft Rules require more than the host states in this regard, the protocol will not provide enough information to protect resources. Adams (p. 20) also states the results of monitoring should be made available to the owners of the tested wells and the general public, regardless of the sampling results. We recommend posting on the Commission’s website.

We support mapping and location of all subsurface artificial penetrations, geologic fractures, aquifers and testing before, during and after stimulation outwards from the well bore for at least 2000 feet. Depending on the geologic conditions, the radius may not be equidistant but should be shaped based on the dip and strike of the geologic formations of the site. Also, after completion of the horizontal well bore, testing should be required 2000 feet outwards from the terminus of the bore, as described in these Comments under Section 7.5.b.4 (Rubin, setbacks).

Section 7.5(h)(2)(i)(A)(2) surface water sampling. Sampling before construction and alteration is essential to establish baseline conditions. The proposed protocol in the Draft Rules is not adequate. Below we provide overall monitoring recommendations that are necessary to ensure that the DRBC has the basic information required to meet its legal mandates.

The Draft Rules go further than the inadequate state requirements in way of monitoring requirements but more monitoring needs to be required in the regulations in order to ensure SPWs do not decline over time and to protect these resources with quick and effective emergency response and pollution response if and when incidents happen.

Monitoring must also be able to detect slow moving leaching pollution that has been projected to be a possibility.

Because of the nature and toxicity of the hundreds of chemicals used in the drilling process, more parameters need to be tested both pre and post drilling and for a longer duration of time to ensure SPWs do not decline. Water quality criteria need to be established for additional pollutants of concern.

In absence of a cumulative impact study, all stream data for all parameters including water chemistry (real time and grab samples), benthics, fish, mussels, must be commenced at least one full year before drilling can begin in order to have good baseline data. Cost of this monitoring work should be funded by the operators and be a requirement of receiving a drilling permit. This is necessary in order to establish trends and baseline conditions through the seasons since SPW are not to degrade in quality.

Modeling to understand the implications of built-out should be developed before any regulations are finalized. Modeling for the Delaware River Basin would inform regulatory development and should be funded by the operators (Parasiewicz, p. 15) Models must be informed by accurate science and monitoring on the ground to ensure inputs are correct.

Because degradation is not allowed in SPW, required data analysis and interpretation of regional monitoring studies should be conducted on a sub-watershed basis in order to know when the degree of drilling has begun to show decline in our streams. This study should be conducted with agency, academia, and the operators' consultants together and released for public review and comment. The operators should pay the bulk of the costs associated with these sub-watershed studies.

Water chemistry stream monitoring requirements need to be more frequent and include both grab samples and also real-time data sondes. Duration of monitoring should continue regularly through the life of the well and beyond for a minimum of thirty years, based on expert projections of the fate & transport of chemicals. The Commission should establish a fund for water quality analysis of a number of analytes to allow a determination if domestic water or surface streams in the defined area has been impacted by hydraulic fracturing. This fund should receive contributions from the companies that drill the wells sufficient to have a source of continuing funds for at least 30 years (Miller).

The Draft Rules should establish a real-time satellite-based monitoring network at areas of concern in the Delaware River Basin in order to provide monitoring data to resource agencies the regulated community and the public and to allow timely detection and response in the case of pollution incidents. This type of network must also be established in reference watersheds for comparisons. This network of sondes should be required as part of the permitting process. Operators should pay to install and maintain these sondes and a collaboration of agencies could be involved. This data would supplement and enhance the DRBC requirements for monitoring already established in the regulations (building on the SRBC network). Sondes requiring downloads could also be located in further headwater reaches nearer the pad sites and could be checked if satellite based equipment detect a potential pollution event.

Data need to be made available to the agency and the public electronically and online in real-time format for parameters where this is technologically possible (similar to Susquehanna River network with possible lessons learned and improvements). (water level, pH, conductivity, dissolved oxygen, and turbidity are indicators to measure).

In addition to macroinvertebrates, longer lived species, such as mussels and fish should be monitored & populations documented – again to ensure no degradation & no harm to endangered or threatened species.

Project sponsors should not be permitted to propose alternative analytical methods to those specified by the Commission.

Water withdrawal location monitoring is needed and it is not clear from the regulations what is required. In addition, public signage and placards of trucks for the public to differentiate freshwater trucks from flow backwater trucks must be clear and visible from a distance (colors must vary between the two types of trucks – hose colors could also vary).

Approved withdrawal sites must be clearly marked and visible by the public. Surveillance cameras or live-cams should be present at each of the withdrawal locations and made available on-line in real-time for the public to ensure dumping does not occur.

All professionals contracted by operators to sample should be required to attend agency led sampling protocol trainings to ensure accurate methods to receive proper certification.

Pre-alteration surface water monitoring study reports should be made available for public review and comment for each plan submitted before monitoring is conducted.

The lag time from data collection to data sharing with agencies and the public cannot be in excess of 30 days and spreadsheets of this data should be made available on a website to the public.

The Commission's own monitoring and enforcement staff & resources need to be increased to ensure no degradation of SPWs occurs. The Draft Rules should provide a table showing the number of state inspection and enforcement personnel that will be assigned to the oversee Delaware River Watershed exploration and production activities. The Draft Rules should also provide information on the amount of state funding for this work. (Harvey p. 5)

Website portals with mapping on the Commission website will be critical for the public to track gas development in their community. The Commission can build on PA's current online database system and website clearinghouse of information on shale drilling. In general, all submitted applications, maps, reports should be available to be viewed by the public on-line. This is needed to ensure accurate and timely review of operator's projected to have multiple permit applications in place at once. All applications need to have public review process included⁸⁰.

Though DRN does not support discharges of wastewater at permitted plants in the Basin, if this is allowed, satellite based sondes should be required as part of the permitting process below the outfalls of these discharges and real-time data should be available on a public website. This would be in addition to grab sampling requirements for constituents found in drilling wastewater and flowback water. Macroinvertebrate sampling downstream of discharges should also be required.

The Draft Rules should require the operators to maintain an electronic tracking system that will account for all water withdrawn from a site. The electronic tracking system would be used to track wastewater movement from pad site to disposal areas. This system would be similar to what mail carriers use to track packages and deliveries. Data would be accessible online and text or email alerts would be established to be sent automatically if certain conditions are met that might indicate a problem.

The Draft Rules should also require that best technology and best practices be used to monitor, model, design, implement, collect data for, and monitor fracture treatments, and that the data be made publicly available. Best Available Technology (BAT) should be required for all technical aspects, machinery, and equipment used; the Draft Rules should be changed to require BAT in all aspects. (Harvey p. 6)

The proposed surface water sampling and mapping is not sufficient and should be revised. In addition to upstream and downstream surface water monitoring to water bodies included in the regulations - which is a good first step - automatic data loggers or continuous monitoring sondes should be required to be installed upstream and downstream of pad sites. These loggers should be funded by the operators and would help with better detection of pollution problems. More sophisticated data sondes that are satellite based should be required as part of the permitting process. These sondes would be located downstream of planned areas for development and would help detect pollution problems or degradation over time. The upstream data loggers could then supplement to help define where the pollution input may be occurring. This combination or best location of monitoring devices could be determined by the operator with guidance from the DRBC but should be a requirement of the permitting process with costs passed onto the operator. This system would reduce the cost of data collection through the utilization of advance technologies⁸¹.

Continuous data logger systems are also critical downstream of any “treatment plants” in the basin that may be allowed to accept waste (though there should be no such allowance in the Delaware Basin since treatment is inadequate).

Sondes and loggers should be equipped to automatically monitor temperature, dissolved oxygen, flow, conductivity, specific conductivity, and turbidity. Sondes and probes should be installed at least one year before drilling is allowed to begin to determine year-long trends in conductivity to have a good baseline⁸². DRBC should consult with SRBC and USGS to determine and learn from the network of sondes installed in that basin. Continuous monitors should also be connected with the Delaware Valley Early Warning System as well as available to the public through a web portal.

Macroinvertebrate sampling is critical to determine changes in water quality over time and included by DRBC in the regulations. DRBC should ensure that sampling is conducted by biologists specifically certified and trained in the field to collect these samples. Habitat and station selection of these samples is important. A DRBC certification course should be required of all samplers hired by operators. Protocols for macroinvertebrate surveys should be rigorous for legal challenges due to the significant risk and harm possible. In addition, other surveys by the agencies (paid for by the operators through the monitoring fee (proposed \$2,000) which should be increased significantly) on species like mussels and fish should be conducted to determine any impacts over time⁸³.

How many biologists and DRBC staff monitors does DRBC plan to add to its staff to be able to ensure SPWs are not declining over time and to oversee all of the monitoring needed is being conducted and analyzed in a timely manner?

How will DRBC determine a trigger for stream degradation and when that occurs, how will that data get put into action with responsive moratoriums on additional drilling? No degradation is allowed in SPWs. Should gas development be allowed in the Basin, Daniels recommends that a provision be placed in the

Draft Rules for a process to institute of a moratorium on drilling in the future to address gas development related issues. (Miller p. 16) With the BP Deepwater Horizon oil well disaster in the Gulf last year, a moratorium was found to be essential. The Commission could easily face a similar catastrophic situation or the need to address local, regional or basin wide cumulative impacts that would require a moratorium on gas development activity. It should be set up now in the Draft Rules so that there is not a scramble during a crisis.

In addition to data loggers, more frequent grab samples and analysis for additional and more extensive parameters should be required on a more protective and frequent basis. During all phases of the pad site from land clearing to the production phase, sampling at least every two weeks is recommended to supplement data available from the continuous data loggers. The specifications and parameters list to be determined by the ED should include a broad list of constituents that reflect the nature of the chemicals used in fracking, the nature of the flowback constituents and the interactions between different chemicals. Chemicals formed when mixed with the environment, like 4 Nitroquinoline 1-oxide (4NQO) must be included in this list for monitoring. Glycol ethers like 2-butoxyethanol should also be monitored. DRBC should consult The Endocrine Disruption Exchange (<http://www.endocrinedisruption.com/chemicals.multistate.php>), New York's SGEIS⁸⁴, Volz study,⁸⁵ USGS recommendations⁸⁶ and other sources to ensure a thorough and comprehensive sampling list is developed for oil and gas monitoring. This list must be comprehensive to protect the watershed and community health and should be shared for public comment when developed before finalized.

Holding times for things like radioactive constituents like radium-226 must be outlined and adhered to rigorously for this testing and a certification program may be best to ensure data is collected accurately by the operator consultants. As mentioned in Harvey, disclosure of the chemicals is critical for this step to occur effectively. (Harvey p. 19)

DRBC's Proposed Regulations require groundwater and surface monitoring pre- and post-development which is a good first step, but they do not require operators to provide a list of chemicals for approval prior to use. The list of chemicals provided for approval should include the chemicals' formulas and information on the compounds in the chemicals. Absent that list, it is not possible to conduct baseline monitoring to determine whether those chemicals existed in the environment prior to gas development. Determining whether those chemicals existed prior to development is necessary for determining whether pollution has occurred. (Harvey p. 19)

Operators should not be allowed to propose an alternate analytical method to those specified by the Director, as is proposed under (4) in this section. DRBC should design a certification program to ensure sampling techniques are adhered to and require operator consultants to get certified through the trainings.

Further under (5), monitoring must be consistent in all approaches to best compare pre and post sampling as outlined here. This should apply to macroinvertebrate sampling to ensure similar sampling techniques allow for comparisons pre and post drilling conditions. Triggers need to be put in place to determine a decline in aquatic life and when decline is determined, drilling should cease. Since no build-out or cumulative impact is being conducted, these triggers will be key to ensuring degradation does not occur.

In addition to the pre-construction testing discussed above, a soil gas and seismic survey of the area should be required. Numerous joints and pathways throughout the Appalachian basin are known to exist but have not been rigorously documented. This should be done to assess the potential for pollution pathways. Rubin explains (Rubin p. 49-54):

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., planar, 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, Lustgarten (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 chemicals are known to migrate, as discussed above and in New York City’s comment to NY state regarding the DSGEIS in 2009⁸⁷. The report discussed groundwater contamination and methane migration through natural fractures and grouting errors in Garfield County, Colorado. The migration of fracking chemicals into overlying groundwater, watershed streams, reservoirs, and directly into tunnels is a reasonably foreseeable risk. A well-documented case occurred in Garfield, CO in 2004 where natural gas was observed bubbling into the streambed of West Divide Creek where high levels of benzene were also found (90 micrograms per liter – 90 times the NYSDEC water quality limit). Groundwater was contaminated with benzene in this area (200 micrograms per liter) too and has required remediation since 2004. Operator errors in conjunction with the existence of faults and fractures led to significant quantities of formation fluids migrating vertically nearly 4,000 feet and horizontally over 2,000 feet, surfacing as a seep in West Divide Creek. The Marcellus shale and the

West Delaware Tunnel ranges between 3,000 and 5,500 feet, well within the vertical distance seen in the pollution incident in Garfield County, indicating very real potential for methane migration to the city water supply tunnels. Subsequent studies have found ambient groundwater concentrations of methane and other contaminants has increased regionally as drilling activity increased, and cause was attributed to inadequate casing or grouting in gas wells and naturally occurring fractures.⁸⁸

Recommendation from Hazen & Sawyer (Page D-2): Prohibit the transport of fracturing chemicals and waste products on roads adjacent to public water supply reservoirs or major inflow streams. This would reduce the risks of acute spills directly to stream or reservoirs. We endorse this recommendation to the Draft Rules.

Horizontal well laterals can extend for over a mile from the actual well pad. Hydraulic fracturing is specifically designed to fracture rocks and intercept and enhance hydraulic pathways and this process is difficult to predict accurately⁸⁹ Mitigation of risks of drinking water and streams require large setbacks that are not just for the vertical well but also for the entire length of the wellbore since the lateral well bore where hydraulic fracturing occurs, is a key area for potential pollution⁹⁰, as discussed in this Comment under “setbacks”.

Section 7.5(h)(2)(i)(B) Post Construction Report. All gas wells should be monitored. Monitoring should be done immediately after construction and on a regular basis after that. All monitoring results should be made public by posted on the Commission website. Monitoring needs to be more frequent than annual requirements for streams to detect pollution problems. A combination of Real-time Sondes and data loggers should be required for the following indicators: temperature, dissolved oxygen, flow, conductivity, specific conductivity, and turbidity and this data would be available online through a web portal either immediately for sondes or in batch downloads for loggers. Annual macroinvertebrate surveys are sufficient unless sondes detect a potential pollution problem at which time more rigorous sampling would need to be pursued. Grab samples should also be required at least every two weeks during the life of the well.

After well capping, continued monitoring must be required. Water quality impacts may not be observed for many years, and perhaps long after the production companies have left the area. Funding for routine monitoring, conducted at least once a year, should be required of the gas companies for a minimum 30 years (and perhaps longer, depending on hydrologic conditions) into the future to provide domestic well owners and downstream users/residents of potentially affected waterways have assurance that their water is not being degraded by slow-moving contaminant sources. Salts and natural gas constituents are likely to travel the most rapidly and the water analyses may not be extensive, but if salts or natural gas constituents are observed in a domestic well or surface water body, then further investigation should be required to determine the source of the contamination, well into the future. (Miller p. 4)

Section 7.5(h)(2)(i)(B)(1) & Section 7.5(h)(2)(i)(B)(2). More frequent reporting should be required of the operators than a one year requirement. Raw data should be shared with the Commission and the public 30 days after collection (using an online database system with a web portal) and quarterly reports with analysis should be provided to the Commission and the public.

Regarding Hydraulic Fracture Design and Monitoring the Commission's regulations should require that best technology and best practices be used to model, design, implement, collect data for, and monitor fracture treatments. (Harvey p. 24)

Air monitoring also needs to be included and required in the regulations and set up in such a way that pad sites are targeted along with reference areas where drilling is not taking place. For reasons discussed elsewhere in this Comment, air emissions cause water pollution as they deposit on surfaces. This directly adversely affects the water resources of the basin.

Section 7.5(h)(2)(ii) Hydraulic Fracturing.

Section 7.5(h)(2)(ii)(A). As discussed above, we agree all wastewater must go to approved facilities and there must be adequate tracking and verification of the facilities' ability to process the wastewater safely. We support and advocate for a zero discharge policy, which is in keeping with the Commission's zero discharge policy in its Water Code for SPW. Harvey recommends a zero discharge goal and explains inconsistencies and lack of clarity in the Draft Rules (Harvey p.20-21):

DRBC's Proposed Regulations at 7.5(h)(1)(iv)(A)(1-4) prohibit waste disposal in the Delaware River Basin, requiring all non-domestic wastewater to be disposed of at an approved facility. However, DRBC's Proposed Regulations at 7.5(h)(1)(iv)(A)(5) appear to negate that prohibition by allowing the DRBC to waive this requirement if the DRBC and the host state approves waste discharge to groundwater and/or surface water. DRBC does not provide criteria for what conditions would prompt a waiver of discharge waste to groundwater and/or surface water. No waste discharge waivers should be granted.

Section 7.5(h)(2)(ii)(B). We agree there should be notice at least 48 hours ahead but this should be amended to require a minimum of 48 hours ahead or sooner -- as soon as the operator has scheduled the operation.

Section 7.5(h)(2)(ii)(C). We agree the volume of water used should be metered with a continuous recording device within 5% accuracy but with no waiver provision and no allowance for "if technically feasible or economically practicable as this technology is inexpensive and readily available, as discussed above regarding monitoring equipment. Reports should be filed with the Commission and made available publicly on the Commission website.

Section 7.5(h)(2)(ii)(D). We agree volumes/amounts of chemicals/additives should be submitted to the Commission as described. We oppose the use of toxic and hazardous chemicals for hydraulic fracturing in the Basin and advocate that the Draft Rules prohibit the use of toxic substances and materials,

hazardous materials, chemical hazards, materials that are hazardous to human health or the health of living organisms. We have several points to make on this issue about the related policies and practices.

Hydraulic fracturing solutions contain contaminants that violate clean water standards and/or are not properly regulated, posing an unacceptable risk to the water resources of the basin. Daniels includes in his report a PADEP list of hydraulic fracturing fluids used by operators in the PA. (Daniels, Table 1) He points out that some of the solutions exceed EPA standards for drinking water, while others such as petroleum distillates and hydrochloric acid have no standards. The Water Code does not list these solutions nor does it cite any maximum contaminant levels and neither do the Draft Rules. Daniels explains the problem (Daniels p. 8):

The Water Code of the Comprehensive Plan does not include, among others, the following chemicals that are used in the fracturing of Marcellus Shale to extract natural gas: Petroleum Distillate Blend, methanol, Propargyl Alcohol, Ethylene Glycol, Hydrochloric Acid (see PADEP, 2011; DRBC 2001 (see Table 1)).

Some of these chemicals have maximum contaminant levels set by the EPA, but these levels are exceeded by the reported concentration in the Fracking Solution (see Table 1). For instance, Propargyl Alcohol has a Frac concentration of 0.23 ppm while the EPA limit is 0.073ppm (product vendor BJS); Ethylene Glycol has a Frac concentration of 123.19 ppm while the EPA limit is 73ppm (product vendor Universal). The EPA has not set a limit on hazardous substances such as Hydrochloric Acid, Petroleum Distillate Blend, Ammonium Bisulfate, or Glutaraldehyde, nor has the DRB Commission (see Water Code of the Comp Plan pp. 138-145).

The Water Resources Program FY 2010-2015 raises the questions “Are the current water quality standards adequate? Should uniform criteria be developed?”(DRBC 2010b, p.14). The proposed amendments to the Comprehensive Plan do not give assurance that water quality standards governing the use of chemicals in the natural gas fracking process are adequate to ensure adherence to the Safe Drinking Water Act standards.

The water quality and water quantity protection goals of the Comprehensive Plan and the Water Code are not well served by the natural gas extraction process being proposed, nor adequately protected by the draft regulations proposed.

Parasiewicz states that there is a considerable risk of pollution due to the chemicals used and the opportunity for release from the well sites (Parasiewicz p. 11-12):

As demonstrated in the testimony of Rubin, there is a considerable risk of contaminants reaching the streams and rivers of the Upper Delaware watershed. This can be due to gas and fracking chemicals percolating into the ground water, or to the surface water through blowouts or sedimentation. This would affect not only the water supply for humans but obviously also the aquatic fauna. As demonstrated in the Anderson and Kreeger testimony, this could have lethal consequences for freshwater mussels including the federally endangered *Alasmodonta heterodon*. Mitigating the risks of contamination is

also essential for pollution intolerant species of fish such as trout and macro-invertebrate fauna. Long term contamination usually leads to a reduction in the number of species and overall low densities of animals.

Harvey explains that the Draft Rules fall short of protecting water resources from contamination (Harvey p. 18-19):

DRBC's Proposed Regulations primarily address water withdrawals and waste production at the surface, and assume other potential pollutant pathways will be adequately handled by host states. DRBC assumes that host state regulations, inspections, and enforcement regimes adequately handle: underground transportation of pollution (e.g. stray gas migration and underground movement of fluids); surface oil, chemical and fuel spills; and well control issues. However, host state regulations do not currently address subsurface water impacts in a manner that will protect the Delaware River Watershed.

While DRBC's Proposed Regulations at Section 7.5 (h)(2)(ii)(F) do include some additional subsurface monitoring to identify impact areas, the proposed regulations do not establish any limits on chemical use. Furthermore, DRBC proposes no regulations to govern well construction, or to require technologies and tactics that would prevent subsurface water contamination from occurring.

If the Commission allows chemical use, the Draft Rules should prevent pollution through limiting chemical use, testing of geology and aquifers at gas well sites, adopt best available technology and practices for stimulation of gas wells, establishing rigorous tracking and monitoring, adopt well construction regulations once cementing and casing technology has been developed to produce effective zonal isolation that will prevent fluids used in gas well development from entering groundwater aquifers or surface water bodies, and a full containment and zero discharge policy for wastewaters.

Harvey criticizes the Draft Rules for only addressing after-the-fact reporting (Harvey p.19):

Rather than setting limits on chemical use, DRBC's Proposed Regulations at Section 7.5 (h)(2)(ii)(D) deem it acceptable to rely solely on after-the-fact reporting of chemical use, combined with groundwater monitoring.

Harvey recommends that pollution prevention standards be established to protect subsurface water; that chemical use limits be set to **prevent** the introduction of harmful chemicals into the environment and should require long-term monitoring to track the fate and effect of subsurface chemical transport; and that an applicant be required to provide a list of chemicals, including the amount and concentration of each chemical, for approval prior to use in any part of the exploration and production process. (Harvey p. 20) Harvey includes recommendations for more effective controls in her report. (Harvey, Recommendation Summary p. 4-8) We support these recommendations for the Draft Rules. Harvey also recommends, as stated previously, a zero discharge policy for wastewaters.

The DRBC should revise the Draft Rules to require that hydraulic fracturing solutions consist solely of non-toxic materials. Many professionals in the field are calling for the use of nontoxic fluids for well stimulation; many are saying non-toxic fracking fluids should be required⁹¹. This is because of the many dangerous ingredients in the formulas used to hydraulically fracture wells in the Marcellus shale.

Table 5-3 of New York's SGEIS lists many of the fracking chemicals proposed for use in shale drilling in New York that include biocides, friction reducers, scale inhibitors, proppant, stabilizers, gelling agents, surfactants, corrosion inhibitors, cross linkers, iron control, and acids. Chemical suppliers provided additive product compositional information to New York which includes approximately 260 unique chemicals whose CAS numbers have been disclosed to the New York Department of Environmental Conservation (DEC) and an additional 40 compounds which require further disclosure since many are mixtures. Table 5.4 lists products which only partial chemical composition information has been provided to the DEC. Table 5.6 is a list of chemical constituents and their CAS numbers that have been extracted from complete chemical compositional information and MSDS information submitted to New York and includes nearly 200 products used or proposed for use in hydraulic fracturing operations. Compound specific toxicity data are limited for many of the chemical additives so chemicals are grouped together based on their chemical structure in Table 5-7.⁹²

The breadth and toxicity of these chemicals is unknown in some cases and toxic in others. The chemicals that form synergistically are also not understood. DRBC should require non-toxic fracking fluids to be used in the Basin to prevent pollution to the water resources of the Basin as is advised by Harvey above.

Rubin offers justification for the Commission only allowing nontoxic and non-carcinogenic substances for hydraulic fracturing. He explains (Rubin p. 38-40):

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. The DRBC draft regulations should be revised to preclude the use of toxic chemicals in gas well construction and operation. 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.

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.

The DRBC's Draft Rules must be revised to require that disclosure and reporting of chemicals will be complete and public. If the Commission allows any chemical use there must be full and public disclosure. The disclosure requirements in the Draft Rules do not go far enough. There needs to be disclosure of all chemicals and their CAS number and MSDS sheets, the percent that is being used, the amounts and the exact mixtures in formulas so that toxicity and health hazards can be known. Each batch of fluids must be disclosed and sampled prior to use for each injection process. The sample results and list of ingredients provided to the Commission should be made public by posting on the Commission website. Rubin cautions that the public needs to learn and fully discuss the issues involved with chemicals use for hydraulic fracturing. He recommends that this should come before regulations. (Rubin p. 39) Rubin also discusses disclosure (Rubin p. 39-40):

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.

Certain materials that are not classified by the EPA are of concern and should be flagged as too risky if they pose unknown environmental impacts that could be substantial. For example, will nanolubricants or nanoparticles be allowed in hydraulic fracturing fluids? Or will these decisions all be left to the operator/project sponsor? Miller points out that the large list of chemicals used pose serious management issues because of the many ways they can be released. Miller makes recommendations, with which we agree (Miller p. 1):

The contaminants in produced water consist of naturally occurring contaminants (e.g. radium, salts, hydrocarbons) and additives used in hydraulic fracturing well development. The additives consist of a wide range of substances that may vary with the specific well driller and/or the conditions at a site. While the regulations do require that these substances be disclosed, there is apparently no requirement for specific measurement or identification of these substances in surrounding wells, or in the produced water. This potential list of additives is indeed long and contains a complex variety of compounds used in hydraulic fracturing (see one list from the New York Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, beginning on page 6-19). For example, acrylonitrile was recently identified in water contaminated from hydraulic fracturing wells, presumably from use as a component of acrylonitrile-butadiene-styrene in-situ polymerization to increase the utility of a propping agent.⁹³ No attempt was made to measure this compound in surrounding water wells prior to establishment of the gas wells, and consequently it was unclear if this very unusual contaminant came from the hydraulically fractured well development or from some other source. Because this toxic compound is so unusual, it is highly unlikely it came from a source other than the hydraulic fracturing treatment. Many other additives, transformation products or even products produced during hydraulic fracturing may also be present, and should be on the list of potential contaminants to be measured.

Recommendation: The Commission should clarify the specific contaminants that will be measured (including before, during and after proposed gas development) in domestic water wells and produced water, and this list should be based on the contaminants in the formation water, as well as the additives used in the hydraulic fracturing process and potential compounds formed during the fracting process.. The Commission should also give itself the ability to require additional analytes be measured as the need may arise.

The Draft Rules, since they do not regulate gas drilling and construction issues, also do not address hydraulic fracturing practices outside of the limited issues in this Section. The problems discussed at length by Rubin, Demicco and Harvey in regards to cement, steel, casings, and other well bore construction issues make it clear that the extreme pressures that accompany hydraulic fracturing strain the materials that are supposed to shield aquifers from hydraulic fracturing fluids and deep geology contaminants and gases. Demicco explains how grout failure can lead to widened rock fractures that propel liquids horizontally away from the gas well 5 to 10 times faster than vertical movement when

under the extreme pressures imposed—basically, causing an outward explosion that could reach 10,000 feet outward quickly. (Demicco p. 4) Pressures of 15,000 psi or more are used in hydraulic fracturing. (Demicco p. 17) Typically, wells in the Barnett shale in Texas are re-hydraulically fractured within 5 years or sometimes less to keep the well productive. Repeat fracturing operations in the same well bore provide heightened risk of grout, cement or casing failure. The Commission should research this issue. Based on current knowledge, the Draft Rules should prohibit the re-fracturing of existing wells until such practice can be proven safe, especially considering the wealth of data showing that current well construction practices and regulation are not reliable and do not provide necessary protection to aquifers.

Section 7.5(h)(2)(ii)(E). We agree that metering of volumes is important but further actions and daily continuous reporting are needed to provide accountable oversight as discussed elsewhere in this Comment.

Section 7.5(h)(2)(ii)(F) Sampling. The proposed sampling is not adequate. The key protocol details of frequency, sample parameters, analytical methods and required detection limits cannot be left to the Executive Director as the Draft Rules allow. The issue of “what is in the flowback and production water” is one of the most controversial issues involved with gas development and the public and local communities are very interested in how these wastewaters will be sampled. There should be a public rulemaking process on these protocols. It is totally unacceptable to allow this to be decided behind closed doors and without any public participation in the decisionmaking. See our Comments regarding Monitoring.

Harvey states that the Draft Rules should require additional testing of gas composition. (Harvey p. 19):

DRBC’s regulations should, but currently do not, include gas composition testing. If gas is found in a water well, it is often necessary to know the gas and water composition from nearby formations to determine whether gas and associated fluids have migrated from a hydrocarbon reservoir. At present, this information is not generally available to those who are investigating problem water wells, even though individual companies may have the information.

To ensure that there is sufficient information to identify the source of gas found in a water well, a reference well system must be established to document gas and water composition. The composition of gas (the relative volume of methane and higher hydrocarbons), the isotopic characteristics of the gas, and any associated fluids should be analyzed. The resulting information should be stored in a publicly accessible database.

Project sponsors should be required to add non-toxic signature or tracer chemicals to fracking fluid to ensure if pollution is detected, the source of pollution or responsible party from which that pollution originated, can be determined. This is a critical requirement missing from the regulations. This requires use in the fluids before alteration and injection and it requires sampling after hydraulic fracturing.

Rubin recommends tracers to be used to positively identify project sponsors responsible for pollution incidents. Rubin explains:

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.

Section 7.5(h)(2)(ii)(G) and Section 7.5(h)(2)(ii)(H) Storage of flowback and production waters. We agree that flowback and production waters must be stored in water tight tanks for temporary storage on the well pad site or it is to be transported for appropriate treatment and that it should not be transferred to another site for use. Unauthorized piping of these fluids have led to spills and accidents in PA where operators have lain pipes on the ground, across streams, through culverts and along lakes, roads and ditches without any standards; this has led to pollution releases, as verified by the PADEP website.

As stated elsewhere in this Comment under Section 7.4, we oppose the reuse or reinjection of these fluids for well stimulation unless all contaminants are removed and the water is of the highest quality. These wastewaters are highly contaminated and pose a substantial health and environmental hazard if released. The Draft Rules should contain detailed specifications for the tanks, as discussed in (iv) (B) below.

Section 7.5(h)(2)(iii) Drilling Fluids and Drill Cuttings from Horizontal Wellbores in the target formation.

Section 7.5(h)(2)(iii)(A). We agree that drill cuttings must not be buried on site as is allowed by the host states. We do not agree that the prohibition should only apply to horizontal well bores in a target formation. The Commission offers no justification for this incongruity. Cuttings from well drilling are

highly contaminated whether from a vertical well or an exploratory well or a well that does not penetrate to the target formation. The contaminants are hazardous to human health and the ecosystem, wildlife and aquatic life as well as to flora.

The host state regulations allow for contaminated drill cuttings and fluids to be buried under certain conditions. The cuttings can be buried as close as 20 inches to the groundwater table. There is no ongoing sampling required of the burial site and it does not have to be marked in the field so its location is known. This amounts to a small hazardous waste dump with no permanent markers in backyards, barnyards and forests everywhere drilling occurs. We submitted Administrative Hearing reports on the record to the Commission documenting the hazardous nature of these cuttings and fluids; the reports are appended to this Comment.

Harvey explains (Harvey p. 21):

DRBC's Proposed Regulations at Section 7.5 (h)(2)(iii) only cover drill cutting and drill fluid waste handling requirements for "horizontal" wells in the "target" formation; the proposed regulations ignore the fact that drill cuttings and fluids used in the well above the "target" formation can be harmful to the environment if improperly handled (they can contain Naturally Occurring Radioactive Materials (NORM), heavy metals, and/or other chemical additives). DRBC's Proposed Regulations should include drill cutting and drill fluid waste handling requirements for the entire well, not just select intervals.

Section 7.5(h)(2)(iv) Wastewater Storage.

Section 7.5(h)(2)(iv)(A). The Draft Rules should require secondary containment and continuous state of the art leak detection and reporting in real time, should be strictly limited in retention time (no extensions of resident time allowed) and should be fitted with the best available technology filters and venting mechanisms to prevent the escape of noxious, dangerous, or hazardous air emissions. The tanks need to be marked and placarded accurately so the contents are readily known for worker and local community safety, to avoid errors in handling, and in case there is a spill or leak. Miller recommends leak detection systems due to the proximity to aquifers; we support his recommendation (Miller p.3):

As discussed above, the produced water is highly contaminated, and any spills will be problematic, and threaten both surface and groundwater. Reuse of this contaminated produced water will also generally increase the contaminant load in the produced water in the subsequent well, both from additives and the other contaminants because there will be no dilution of the contaminants. If a leak occurs in the top few hundred feet in the well being fractured, the leak will contain very contaminated water under high pressure, and even a small leak can release large amounts of contaminants that can degrade usable domestic water. The Draft Regulations do not provide a mechanism for the well drillers or the Commission to know there is a leak, except by the observation of increased salt loads in domestic water in the years and decades ahead. Leak detection systems that could be used to detect a leak rapidly in usable aquifers should be identified and required.

Recommendation: The Commission should examine this question in some detail and require the Best Available Technology for leak detection during hydraulic fracturing when produced water is used for the fracturing process. The Commission should also require best available technology in well construction practices and well log data requirements to safeguard fresh water.

Harvey points out the special problems with NORMS and heavy metals in the handling of wastewater:

DRBC's regulations should include special handling, treatment, and disposal requirements for drilling waste and equipment that contains Naturally Occurring Radioactive Material (NORM), mercury, cadmium, and/or other heavy metals. The Marcellus is considered "highly radioactive" shale.⁹⁴

Section 7.5(h)(2)(iv)(B). We oppose recovered flowback reuse as a water source, as discussed in this Comment. We oppose the use of centralized storage facilities to hold these fluids subject to host state regulations. There are few regulations that govern these facilities in the host states and those that are in place are not meet best available technology or practices. Setback limits from ecologically sensitive features and people are not in place or are inadequate. These impoundments are a means of dispersing pollution through multiple pathways. Volatilization to the air, leaks through liners or overtopping, spills and accidents while fluid is being handled and transported, and the risk of pollution release when the impoundment is closed, all are pathways of pollution. Access to these impoundments by wildlife (both birds who fly in as well as terrestrial wildlife) offer another way that contaminated waters can enter the larger environment. The incongruity of the Commission in allowing these large open pits but not allowing open pits on the well site is puzzling. The Draft Rules must be changed to not allow any open storage of these wastewaters.

Miller explains why open storage is so dangerous (Miller p.2):

The quality of the liners in open basins, the leak detection mechanisms and the dismantling of the basins are not considered in these regulations. Liner leakage is a major problem whenever contaminated water is stored for any length of time, and even a small leakage of the highly contaminated produced water could present a major environmental problem. This example and many other technical components of well construction and associated activities are not adequately covered in the Draft Regulations.

Section 7.5(h)(2)(iv)(B)(2). It is implied that a docket can have a condition that allows a waiver of the prohibition of open storage of recovered fluids on the well site. This should be clarified and should not be allowed. Yet Section 7.5(h)(2)(iv)(B)(4) seems to contradict this. Please clarify.

Section 7.5(h)(2)(v) Wastewater Treatment and Disposal Plan. We agree that this plan is needed for reasons stated in this Comment. We are opposed to discharge into ground or surface waters. We oppose underground injection wells in the Basin. Underground injection wells or any discharge of wastewater

anywhere within the Basin should be prohibited due to the technological difficulties of treating drilling wastewater as outlined in Miller⁹⁵, Volz⁹⁶, and Harvey⁹⁷. A zero discharge policy should apply as discussed in this Comment.

Section 7.6 Wastewater Generated by Natural Gas Development.

Section 7.6(a) Approval Requirements. We oppose the discharge of gas development generated wastewater to the surface or groundwaters of the Basin. No exceptions and no exemptions or special considerations should apply at any time. See Section 7.5 Comments.

Wastewater quantities/volumes must be monitored electronically and by log from cradle to grave and as specified in the proposed regulation but DRBC must go further. In addition, it is critical that the wastewater at each well pad site, before leaving the site, needs to be analyzed for constituents of concern since different well pads may generate different wastewater analytes (New York SGEIS). As indicated by Glenn Miller, since produced water is highly saline and radioactive with hundreds of contaminants, there needs to be specific measurements of the wastewater/produced water in place as it appears this is lacking from the regulations. (Miller p. 1)

There also needs to be special handling in place. MSDS sheets, a full disclosure of chemicals, and a plan for emergency cleanup must accompany the wastewater on its way to disposal by truck so emergency response personnel and inspectors can access this information easily in case of emergency and/or for routine inspections. An electronic real-time cloud-based database and tracking system with scanners (similar to what US Postal Service uses that tracks packages) must be developed and paid for by the drillers to account for this waste from cradle to grave and to track wastewater via electronically as well as by hand and in logs. The electronic tracking should be available to DRBC and to the public in real time and checks should be put in place to automatically flag if a truck or delivery that was expected at a wastewater plant did not arrive in the specified time expected to alert officials of a missing delivery. In this way, there would be better policing of tremendous amounts of waste being carted by truck from cradle to grave.

This oversight is needed as indicated by FrackNet, a two day enforcement effort by multi-agencies last year that targeted wastewater flowback trucks in PA that found many trucks out of compliance with safety hazards. 131 trucks were put of service during the sting operation. According to Noonan, 731 commercial trucks were inspected March 14-15 during “Operation FracNET.” Fourteen drivers were placed out of service and state troopers issued 421 traffic citations and 824 written warnings. In addition, PADEP personnel issued 35 citations and 13 written warnings.⁹⁸ The issue of transportation of these hazardous chemicals must also involve proper oversight and regular inspections.

Section 7.6(b) Treatability Study. There are no details provided in the Draft Rule on the treatability study. This needs to be provided for informed comment. But all comments made above in Section 7.6 A

“Approval requirements” apply here and rationale is provided in Miller⁹⁹, Volz,¹⁰⁰ and Harvey¹⁰¹ and Rubin¹⁰² reports. Because there are so many chemicals in flowback water and because unique chemicals and gases can form in the gas well stimulation and extraction process, and because there is no effective treatment available to process and remove all of these chemicals, we oppose their discharge in the Basin. The Commission, as stated elsewhere in this Comment, should apply its zero discharge policy that is in place for SPW throughout the Basin due to the dangerous makeup of the waste fluids. This should be the policy for both solid and liquid waste. Furthermore, to our knowledge, there is no existing treatment in the Delaware Basin that is specific to treat only oil and gas wastewater (desalinization type plant) and with the discharge data provided by Volz¹⁰³ for the Josephine Facility, the DRBC should not consider other existing plants to be a feasible or effective treatment option for highly contaminated and saline flowback water.

Because the Draft Rules and Water Code as well as host state regulations that govern wastewater facilities do not include treatment criteria for all of the harmful constituents in drilling wastewater, the Commission cannot rely on existing permit requirements by the state or the Commission to be adequate to protect human health or aquatic life from these discharges.

Section 7.6(c) Ensuring non-exceedance of primary and secondary safe drinking water standards.

As stated earlier by Daniels, drinking water standards are violated by many of the fluid mixtures used. Many contaminants are difficult and expensive, if not technically possible, to be removed by wastewater plants and/or by drinking water treatment facilities. Some pose serious pollution issues due to stream impacts for fish, aquatic life, and wildlife and some are problems when used as untreated intake water for industrial purposes (such as power plants or manufacturing facilities). The list provided in the Draft Rules is not inclusive enough and the Water Code does not include all the chemicals that are present in these wastewaters either. An obvious missing parameter is bromide which can manufacture disinfection byproducts that are carcinogenic when it enters a chlorinated water system; others are listed below from Bishop’s report. There are many endocrine disruptors found in this wastewater that have human and wildlife impacts that are just beginning to be understood.¹⁰⁴

As indicated above, there should be no discharges of wastewater from gas drilling allowed in the Delaware River Basin as there is no adequate treatment available to effectively treat the wastewater generated (see Section 7.6a).

Because hundreds of constituents are in the drilling wastewater, additional parameters need to be analyzed to what the Commission lists in this section under EPA’s Primary & Secondary Standards. The standards in place are not up to pace with the chemicals being produced in the wastewater therefore they are inadequate and need significant updating before any drilling is conducted. As discussed in this Comment in Section 7.5, additional parameters should also include for example, (but are not limited to): magnesium, bromide, sulfate, 2BE (and other glycol ethers), benzene, ethylbenzene, toluene, and xylene.

Section 7.6 (c) – (e). Bishop adds the standard panel of water tests in this section omits three important analytes: radon (Rn), hydrogen sulfide (H₂S) and 4-nitroquinoline-1-oxide (4-NQO). Although these chemicals are not used as drilling or fracturing additives, they are widespread in flow-back fluids and/or groundwater. (Bishop p. 16 and 18)

Bishop points out one chemical compound consistently encountered in flowback fluids from Marcellus gas wells in Pennsylvania and West Virginia was 4-nitroquinoline-1-oxide (4-NQO). This is one of the most potent carcinogens known, particularly for inducing cancer of the mouth. It is not used as a drilling additive and is not known to occur naturally in black shale. No studies have been published to date with respect to chemical interactions which might account for its consistent presence in flowback fluids (verified in the NYS Draft Supplemental Generic Environmental Impact Statement, 2009, Chapter 6). 4-NQO is dangerous at parts-per-trillion (ppt) concentrations, well below its levels reported in gas well flowback fluids (Bishop p. 16-17).

The Draft Rules should require that tests on waste fluids be based on disclosure of additives used in gas extraction processes, in addition to standardized parameters (Bishop p. 18) Also, each batch of solution used should be sampled and the results submitted to the Commission and posted on the Commission's website.

Section 7.6(d) Effluent limitations and stream quality objectives for discharges to Zones 2-6.

As indicated above, there should be no discharges of wastewater from gas drilling allowed in the Delaware River Basin as there is no adequate treatment facilities existing and available in the Basin to effectively treat the wastewater generated (see Section 7.6a). Also, the Draft Rules should include stream quality objectives that are directly applicable to gas drilling – without this we are not getting a full or accurate assessment of the effects of gas development and possible pollution.

Because there are a large number of constituents are in the drilling wastewater, additional parameters would also need to be analyzed in addition to what the Commission refers to in the basin-wide stream quality objectives found in Section 3.10.3.B and the zone specific stream quality objectives found in Section 3.30 of the WQRs, including the applicable portions of Tables 3,4,5,6,& 7. The criteria in place are not up to pace with the chemicals being produced in the wastewater therefore they are inadequate and need significant updating before any discharges would be allowed. We recommend a zero pollution discharge policy, consistent with the Commission's SPW requirements as per the Water Code.

Section 7.6(e) Basin-wide effluent limitations and stream quality objectives.

Please see comments in Section 7.6a and 7.5, there should be no discharges of wastewater from gas drilling allowed in the Delaware River Basin (a zero pollution discharge policy) as there is no adequate treatment facilities existing and available in the Basin to effectively treat the wastewater generated (see

Section 7.6a). See also Volz report for more information on ineffective treatment at the Josephine brine treatment plant¹⁰⁵.

Treatment challenges and hurdles with technology should spur the DRBC to prohibit “treatment” or discharges of drilling wastewater in the Basin; a zero pollution discharge policy should be included in the Draft Rules..

Miller states the radioactive elements in wastewater do not “go away”, but are simply concentrated in some other form if removed from the produced water. Naturally Occurring Radioactive Materials (NORM) are either not regulated or poorly regulated, and proposals have emerged to allow discharge of this saline and radioactive water directly into a saline environment. The data on the toxicity of radioactive materials to marine and estuarine ecosystems are scant, and the Commission should prohibit any discharge of produced water into any estuarine systems, due to this issue (Miller p.3)

The tidal Zones 2-6 of the Delaware Basin should also be provided the same regulatory protection as the non-tidal Zone 1 in regard to wastewater – zero pollution discharges allowed from drilling wastewater with no exceptions, exemptions, or waivers allowed. Wastewater cannot be adequately treated as illustrated by Volz, Miller, and Harvey cited in Section 7.6a.

In the tidal zones, Partnership for the Delaware Estuary and the Academy of Natural Sciences have discovered diverse populations of native endangered mussels– two species thought to be extinct in PA and NJ (alewife floater and tidewater mucket) and two species listed as critically imperiled (pond mussel and yellow lampmussel), and two species considered vulnerable (creeper and eastern floater)¹⁰⁶ and the surviving population of Atlantic sturgeon also reside here.

Further down river in the Bay, there are populations of horseshoe crabs and oysters, two important species of the Delaware River. Allowing inefficiently treated wastewater to be discharged here would be detrimental to this ecosystem and the threatened species that rely on it. Mussels and oysters, because of their sessile nature, makes it difficult for them to withstand, or recover from, lethal and chronic impacts to which these animals are sensitive, such as increased siltation, water quality alteration, hydrologic alteration, and introduced species¹⁰⁷. The tidal nature of these zones also means water travels upstream and downstream with the tide; therefore, it is critical that discharges are not allowed in these zones or the non-tidal zones of the Delaware River or any of its tributaries including the Schuylkill River.

The Commission’s TDS criteria may not be protective of aquatic life. Pennsylvania revised TDS requirements and criteria that closely match the 500 mg/L criteria recommended by the USEPA (PA Bulletin 2010). Current Commission regulations include a TDS water quality standard of 500 mg/L basin-wide, and also provide for a maximum increase in TDS of 33% over background by any proposed discharge (or group of discharges) as a means of minimizing effects on aquatic biota and keeping TDS at the more dilute levels seen through much of the basin (DRBC 2008a). Both the existing water quality

defined by Special Protection Waters regulations and recent unpublished data (DRBC 2006-2009) indicate that TDS in Special Protection Waters streams and rivers typically ranges between 50 mg/L and 100 mg/L, five-to-ten times below the common 500 mg/L TDS criteria (DRBC 2008a, DRBC *unpublished data*). Thus, the Delaware River and its Special Protection Waters tributaries currently maintain concentrations of dissolved solids (including salts and other compounds) far below EPA-recommended criteria¹⁰⁸. The proposed standard would result in degradation of existing water quality so should be revised to protect the above standard condition of the river and its tributaries. The Draft Rules should be revised to reflect this.

Wastewater should also not be allowed to be injected into existing mine voids or other underground injection wells. One of the unexpected impacts is harm to bats in bat caves. Other cave dwelling species and other threatened and endangered species can also be impacted by injections and gas drilling and well bore fracturing as well. Rubin explains (Rubin p. 58-59):

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 buildup 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 buildup 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.

Discharges of radioactive materials and the large number of chemicals that have been found to exist after treatment should not be allowed in the Basin. Normally occurring radioactive materials or NORMs – radium 226, a highly dangerous derivative of uranium, was found by NYSDEC to be in Marcellus wastewater in amounts thousands of times greater than is considered safe in drinking water. Other radionuclides were also found in the water sampled from Pennsylvania and West Virginia¹⁰⁹. These radioactive materials must be regulated in order to protect water quality, whether in the water column or in solids.

Further, Professor Kenneth Lande, University of Pennsylvania, recently researched radium in Marcellus shale water and its potential human health impacts; he concludes the risks are significant and points out that radium has a 1600 year half life. Using the guidance of the NJ Drinking Water Quality Institute report of 2002, he concludes that the radium concentration in over 30% of the PA wells tested will result in bone cancer in more than 1% of people drinking this water over a lifetime. He also concludes that there is an elevated risk of cancer for people drinking the radioactive water reported in PA.¹¹⁰ See **Attachment 7** Lande, Kenneth, Why is the Marcellus Shale Water so Radioactive? Can We Live with it? Power Point presentation, 4.13.11. The Draft Rules should address radium and other radioactive isotopes and materials in gas drilling wastewater. The Commission also needs to conduct basin-wide modeling.

The Commission updated and added water quality criteria and contaminants for toxic pollutants for Zones 2-6 for the Delaware Estuary and the rule was approved by the Director of Federal Register as of March 23, 2011. However, DRBC does not have all of the water quality standards or effluent standards in place for all of the constituents of concern from gas drilling wastewater; therefore, the Commission cannot protect the River or recreational users from harm from these discharges. For example, strontium, radium, 2-butoxyethanol, all highlighted in Volz report on wastewater discharges from the Josephine Brine Plant¹¹¹, are not included on the revised list of contaminants. Other parameters for wastewater that are included in Table 1 the Commission draft and DEP chemicals of concern from drilling that appear not to have a standard in these new toxic contaminant criteria or other water quality criteria include other radioactive constituents such as gross alpha, gross beta, thorium, and uranium. The Commission should compare the various drilling wastewater concerns and reports to ensure and update the standards and criteria are all up to date – this should be done before finalizing the regulations.

The Draft Rules should not allow mixing zones. The mixing areas are inappropriate and overly large. Fish don't know to cross to the other side of the river or a stream or when they might suddenly be in a gas drilling mixing zone. There should be no mixing zones allowed – dilution is not an acceptable solution to pollution. The zone of passage of 50% is not adequate to protect free-swimming or drifting organisms.

Mixing zones of this wastewater should not be allowed under any circumstances also because of health and safety concerns of the constituents in drilling wastewater and the technological hurdles of treatment of wastewater outlined by Volz¹¹².

It is not clear in the regulations how the DRBC plans to deal with the cumulative impact of wastewater discharges. The enormous quantities expected from this industry must be considered and a full build out analysis needs to be conducted with modeling.

There should be no Executive Director consideration of requests for alternatives to the requirements in Subsections A through D for mixing zones.

Section 3.10.3C. of the Commission's regulations state that it is the policy of the Commission to designate numerical stream quality objectives for the protection of aquatic life for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Therefore, more criteria need to be established by DRBC for drilling wastewater constituents before regulations are finalized.

Section 7.6(f) Basin-wide Total Dissolved Solids (TDS) Stream Quality Objective.

Please see comments in Section 7.6a and 7.5, there should be no discharges of wastewater from gas drilling allowed in the Delaware River Basin (a zero discharge policy) as there is no adequate treatment

facilities existing and available in the Basin to effectively treat the wastewater generated (see Section 7.6a). See also Volz report for more information on ineffective treatment at the Josephine brine treatment plant¹¹³.

TDS criteria may not be protective of aquatic life. Pennsylvania revised TDS requirements and criteria that closely match the 500 mg/L criteria recommended by the USEPA (PA Bulletin 2010). Current Commission regulations include a TDS water quality standard of 500 mg/L basin-wide, and also provide for a maximum increase in TDS of 33% over background by any proposed discharge (or group of discharges) as a means of minimizing effects on aquatic biota and keeping TDS at the more dilute levels seen through much of the basin (DRBC 2008a). Both the existing water quality defined by Special Protection Waters regulations and recent unpublished data (DRBC 2006-2009) indicate that TDS in Special Protection Waters streams and rivers typically ranges between 50 mg/L and 100 mg/L, five-to-ten times below the common 500 mg/L TDS criteria (DRBC 2008a, DRBC *unpublished data*). Thus, the Delaware River and its Special Protection Waters tributaries currently maintain concentrations of dissolved solids (including salts and other compounds) far below EPA-recommended criteria¹¹⁴.

According to Miller, the data on the toxicity of radioactive materials to marine and estuarine ecosystems are scant, and the Commission should prohibit any discharge of produced water into any estuarine systems, due to this issue. (Miller p. 3)

The Commission should also prohibit discharge of wastewater that may carry radioactive materials to the estuarine and marine waters of the Basin due to the toxicity of these materials to marine and estuarine ecosystems.

The Draft Rules will not effectively control TDS and salts in the river and estuary. High TDS levels threaten key species and drinking water by exacerbating movement of the salt line, already a risk due to deepening. The Delaware River deepening project, if it is allowed to happen, is going to move the salt line further up river, changing salinity levels at various key locations and as a result jeopardizing: oyster populations by potential re-exposure to MSX and dermo that like the more saline waters, drinking water supplies with higher salinity levels at intake locations, and Atlantic sturgeon by affecting their spawning grounds. The massive take of freshwater promised by gas drilling, and its permanent loss to the Delaware River system, will exacerbate the problems of a moving salt line already exacerbated by deepening by reducing the volume of freshwater flows available for repelling the salt line, particularly during low flow periods. The draft regulations make no account for this synergistic harm on estuary ecosystems and water supplies.

There need to be stream quality objectives for TDS created for zones 5 & 6. TDS includes the chlorides that make horizontal drilling wastewater so salty. Salinity levels in the estuary are important for drinking water intakes, oysters, sturgeon spawning and other species. Allowing unfettered discharge of highly salty discharge, that will merge with the increase salinity levels created by deepening and other changing

dynamics in the River is dangerous to aquatic life and water intakes and cannot be allowed to happen unfettered.

Section 7.6(g) Wastewater Imports.

DRBC should not allow wastewater from drilling from other Basins to be discharged within the Basin. DRBC should not allow any discharges of wastewater in the Basin at all – a zero discharge policy should be adopted due to the technological hurdles of “treating” wastewater produced by natural gas development.

Section 7.6(h) Underground Injection Control.

DRBC should not allow any underground injection of wastewater in any wells or any mine voids or underground caverns. Arkansas Oil and Gas Commission shut down injection wells for drilling waste in January 2010 and is maintaining a 6-month moratorium on any new injections of waste in the state when preliminary studies showed evidence potentially linking injection activities with nearly 1,000 quakes in the region over the past six months. The quakes have decreased in intensity since the injection has stopped¹¹⁵. In Texas, similar quakes have been suspected to the result of injection of wastewater¹¹⁶.

Underground injection, hydraulic fracturing and gas well drilling can destabilize geology in the Delaware River Basin. Rubin discusses and makes a recommendation, with which we agree (Rubin p. 40-45):

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; Amorèse 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. More detail specific to earthquakes, seismicity, and well 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.

The Commission should include potential seismic impacts in a cumulative impact analysis and not move ahead with Draft Rules until this public safety and environmental issue is fully addressed.

Respectfully submitted,



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Attachments:

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| Attachment 1 | Curriculum Vitae, 2011 Reports |
| Attachment 2 | Expert Reports, 2011 |
| Attachment 3 | Curriculum Vitae, 2010 Reports |
| Attachment 4 | Expert Reports, 2010 |
| Attachment 5 | Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations", 4.14.11 |
| Attachment 6 | Volz et.al., Executive Summary, "Containment Characterization of Effluent from PA Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, PA: Implications for Disposal of Oil and Gas Flowback Fluids from Brine Treatment Plants", March 25, 2011 |
| Attachment 7 | Lande, Kenneth, "Why is the Marcellus Shale Water so Radioactive? Can We Live with it?", Power Point presentation, 4.13.11 |

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¹⁵ Tom Daniels, Ph.D., Review and Comments on The Delaware River Basin Commission's Proposed Natural Gas Regulations of December 9, 2010, 2011

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⁴¹ Instream Flows for Riverine Resource Stewardship, Instream Flow Council, Cheyenne, Wyoming, 2004, page178.

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⁴³ **Formation of the Subcommittee on Ecological Flows (SEF),**

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Resolution No. 2003-18 formalized a process for developing and evaluating the feasibility of achieving flow targets to address instream flow and freshwater inflow requirements for aquatic ecosystems in the Delaware River Basin, including the Delaware Bay. It also established a Subcommittee on Ecological Flows (SEF) to assist the DRBC's RFAC (and formerly, the FMTAC) in developing scientifically-based ecological flow requirements for the maintenance of self-sustaining aquatic ecosystems.

The Commission and the Decree Parties committed to participating in a non-binding collaborative process to develop experimental flow management options for the Delaware River and its regulated tributaries. The objectives include development of scientifically-based ecological flow requirements, objective recreational needs assessments, a review of the estuary salinity objective, and an assessment of existing and future municipal, industrial and other water supply needs.

The purpose of the SEF is to assist in developing scientifically-based ecological flow requirements. The SEF provides regular progress reports to the RFAC and works with the DRBC's RFAC and the Water Management Advisory Committee (WMAC) in a collaborative way. Membership of the SEF includes at least one member of the RFAC who is a Decree Party member and at least one member of the WMAC who is not a Decree Party member.

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- ⁸⁶ Ronald Sloto. US Geological Survey Groundwater-Quality Reconnaissance of Proposed Marcellus Shale Drilling Areas in Northeastern Pennsylvania.
- ⁸⁷ Hazen & Sawyer and Leggette, Brashears & Graham. Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed. Final Impact Assessment Report. December 22, 2009
- ⁸⁸ Hazen & Sawyer and Leggette, Brashears & Graham. Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed. Final Impact Assessment Report. December 22, 2009. Page 45.
- ⁸⁹ Hazen & Sawyer and Leggette, Brashears & Graham. Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed. Final Impact Assessment Report. December 22, 2009. D-2.
- ⁹⁰ Hazen & Sawyer and Leggette, Brashears & Graham. Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed. Final Impact Assessment Report. December 22, 2009. D-3.
- ⁹¹ <http://shaleshock.org/2010/08/james-northrup-hydrofracking-faults-aquifer-pollution/>
- ⁹² NYSDEC Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program (DSGEIS), Sept 30, 2009. Pages 5-34 – 5-62.
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- ⁹³ Acrylonitrile **CAS ID #: 107-13-1, Affected Organ Systems:** Developmental (effects during periods when organs are developing) , Hematological (Blood Forming), Neurological (Nervous System), Reproductive (Producing Children; **Cancer Effects:** Reasonably Anticipated to be Human Carcinogens; **Chemical Classification:** None; **Summary:** Acrylonitrile is a colorless, liquid, man-made chemical with a sharp, onion- or garlic-like odor. It can be dissolved in water and evaporates quickly. Acrylonitrile is used to make other chemicals such as plastics, synthetic rubber, and acrylic fibers. A

mixture of acrylonitrile and carbon tetrachloride was used as a pesticide in the past; however, all pesticide uses have stopped. <http://www.atsdr.cdc.gov/substances/toxsubstance.asp?toxid=78>

⁹⁴ Hill, D.G., Lombardi, T.E. and Martin, J.P., “Fractured Shale Gas Potential in New York.”

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⁹⁵ Glenn C. Miller. Report on DRBC Draft Regulations. March 28, 2011.

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⁹⁸ PADEP Press Release: Trucks Placed Out of Service During Multi-Agency “Operation FracNET” <http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16767&typeid=2>.

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¹⁰⁰ Volz et.al. Containment Characterization of Effluent from PA Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, PA: Implications for Disposal of Oil and Gas Flowback Fluids from Brine Treatment Plants March 25, 2011.

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¹⁰³ Susan Harvey. Report Recommendations to Improve the December 9, 2010 Delaware River Basin Commission (DRBC) Proposed Natural Gas Development Regulations Report. April 1, 2011.

¹⁰⁴ <http://www.endocrinedisruption.com/chemicals.multistate.php>

¹⁰⁵ Volz et.al. Containment Characterization of Effluent from PA Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, PA: Implications for Disposal of Oil and Gas Flowback Fluids from Brine Treatment Plants March 25, 2011.

¹⁰⁶ Academy of Natural Sciences. Science Daily.

<http://www.sciencedaily.com/releases/2010/11/101130131545.htm> Nov 30, 2010

¹⁰⁷ Danielle Kreeger & Robert Anderson, Potential for Impairment of Freshwater Mussel Populations in DRBC Special Protection Waters as a Consequence of Natural Gas Exploratory Well Development. Nov 23, 2010.

¹⁰⁸ Testimony of Erik Silldorff, Ph.D., Aquatic Biologist, Delaware River Basin Commission Areas. Statistics In the Matter of Delaware River Basin Commission Adjudicatory Administrative Hearing on Natural Gas Exploratory Wells. November 23, 2010 (Page 3).

¹⁰⁹ NYSDEC Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program (DSGEIS), 2009, Tables 5-8 and 5-9, p. 5-109.

¹¹⁰ Lande, Kenneth, Why is the Marcellus Shale Water so Radioactive? Can We Live with it?, Power Point presentation, 4.13.11

¹¹¹ Volz et.al. Containment Characterization of Effluent from PA Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, PA: Implications for Disposal of Oil and Gas Flowback Fluids from Brine Treatment Plants March 25, 2011.

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