



March 14, 2018

VIA E-MAIL: RegComments@pa.gov

Environmental Quality Board
Rachel Carson State Office Building
400 Market Street, 16th Floor
Harrisburg, PA 17101-2301

Re: Proposed Rulemaking, 25 Pa. Code Ch. 78,
Environmental Protection Performance Standards at Oil and Gas Well Sites

Dear Environmental Quality Board:

On behalf of Berks Gas Truth; Clean Air Council; Clean Water Action—Pennsylvania; Damascus Citizens for Sustainability; Delaware Riverkeeper Network; Earthworks; Environmental Integrity Project; Gas Truth of Central PA; Lehigh Valley Gas Truth; Mountain Watershed Association; Natural Resources Defense Council; PennEnvironment; Pennsylvania Environmental Defense Foundation; Shale Justice Coalition; Sierra Club, Pennsylvania Chapter; Responsible Drilling Alliance; and Stewards of the Lower Susquehanna, Inc., we respectfully submit the comments set forth below and attached technical comments on the proposed revisions of 25 Pa. Code Ch. 78 (“Chapter 78”). The technical comments were prepared with the expert scientific assistance of Susan Harvey, a petroleum and environmental engineer and principal of Harvey Consulting, LLC; Michele Adams, a registered professional engineer and principal of Meliora Design; Kevin Heatley, an ecologist; and Briana Mordick, a geologist and Staff Scientist with the Natural Resources Defense Council.¹ We thank the Environmental Quality Board (“EQB”) for the opportunity to comment on the draft revisions of Chapter 78 and to participate in the lengthy public participation process associated with the proposed rulemaking.

In this letter, we explain the implications for the proposed rulemaking of the Pennsylvania Supreme Court’s recent decision in *Robinson Tp. v. Commonwealth*, 83 A.3d 901 (Pa. 2013) (plurality opinion). *Robinson Tp.* invalidated certain provisions of Act 13 of 2012, a statute amending the Pennsylvania Oil and Gas Act (“Act 13”), thereby securing constitutionally guaranteed rights of the people and protections for public natural resources. This letter also summarizes briefly our chief concerns about the adequacy of the proposed rulemaking under the constitutional standard. Those concerns and others are explained in more detail in our technical comments.

I. Article 1, Section 27, of the Pennsylvania Constitution

One of the express purposes of the Legislature in enacting Act 13, 58 Pa. C.S.A. §§ 3201 *et seq.*, was to “[p]rotect the natural resources, environmental rights and values secured by the

¹ The technical comments are annexed hereto as Exhibit 1. The experts’ resumes are annexed hereto as Exhibit 2.

Constitution of Pennsylvania.” *Id.* § 3202(4). Those environmental rights and values are set forth in Article 1, Section 27, of the Pennsylvania Constitution, as follows:

The people have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment. Pennsylvania’s public natural resources are the common property of all the people, including generations yet to come. As trustee of these resources, the Commonwealth shall conserve and maintain them for the benefit of all the people.

Pa. Const. art. I, § 27 (“Section 27”). In promulgating regulations implementing the purposes of Act 13, as required under the statute, *see* 58 Pa.C.S.A. § 3274, the EQB therefore is bound by the provisions of Section 27.

Section 27 “establishes two separate rights in the people of the Commonwealth.” *Robinson Tp.*, 83 A.3d at 951. The first, prohibitory clause establishes the “inherent and indefeasible” right to “clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment.” *Id.* at 948, 951. Like other rights included in the Pennsylvania Constitution’s Declaration of Rights, Pa. Const. art. I, the environmental right limits the government’s power by prohibiting conduct in derogation of the people’s right. *See Robinson Tp.*, 83 A.3d at 951; *see also id.* at 952 (“The corollary of the people’s Section 27 reservation of right to an environment of quality is an obligation on the government’s behalf to refrain from unduly infringing upon or violating the right, including by legislative enactment or executive action.”).

“The second right reserved by Section 27 is the common ownership of the people, including future generations, of Pennsylvania’s public natural resources.” *Id.* at 954. Those resources include:

not only state-owned lands, waterways, and mineral reserves, but also resources that implicate the public interest, such as ambient air, surface and ground water, wild flora, and fauna (including fish) that are outside the scope of purely private property.

Id. at 955. The third clause of Section 27 establishes the public trust doctrine with respect to those natural resources, which “implicates a duty to prevent and remedy [their] degradation, diminution, or depletion,” *id.* at 957, and an obligation “to act affirmatively to protect the environment,” *id.* at 958. Because the beneficiaries of the trust are “all the people,” the trustee must act impartially toward everyone and must balance the interests of present and future generations. *See id.* at 959. Section 27 therefore protects public natural resources from both immediate severe harm and from small injuries that compound over time and may be irreversible in the long term. *See id.*

Against this background, the Pennsylvania Supreme Court struck down a number of Act 13’s provisions, remanded others to the Commonwealth Court for further consideration, and directed that court to consider whether any remaining valid provisions of the statute were severable from

the invalid sections. *Id.* at 1,000. For the purposes of the EQB’s proposed revisions of Chapter 78, the Court’s decision to enjoin Sections 3215(b), (c), (d), and (e) is directly relevant. Among other things, those provisions establish waivable setbacks of well sites from water bodies and wetlands, identify public natural resources the impacts on which must be considered in the permitting process, deny municipalities any right to appeal permit decisions, and place the burden on the Pennsylvania Department of Environmental Protection (“PADEP”) to prove that any permit conditions imposed to preserve public natural resources were necessary to protect against probable harmful impacts. *See* 58 Pa.C.S. § 3215(b), (c), (d), (e). As we explain below and in our technical comments, the EQB’s proposal for section 78.15 must be substantially revised in light of the *Robinson Township* decision to eliminate the mandatory setback waiver; to expand the scope of protected public resources; and to place the burden of proof on an applicant appealing a permit decision, under the standard routinely applied in a permit appeal.

The key points to remember in considering the implications of the *Robinson Township* decision are that the rights of the people are inherent and inalienable and that the obligation of the governmental trustee is to preserve public natural resources (the corpus of the trust). *See Robinson Tp.*, 83 A.3d at 948, 956. By invalidating specific provisions of Act 13, the Supreme Court thus did not leave the EQB without the power to regulate in defense of clean air, pure water, and the natural, scenic, historic and esthetic values of the environment. To the contrary, the Court lifted unconstitutional restrictions created by Act 13 on the government’s exercise of its duties as public trustee. In revising Chapter 78, the EQB is constrained by Section 27—and the stated purpose of Act 13 to protect the environmental rights and values secured by the Constitution of Pennsylvania—to ensure that the people’s rights are not infringed and that public natural resources are protected for current and future generations.

II. Principal Deficiencies of the Proposed Rules

The attached technical comments describe in detail concerns we share about the adequacy of the proposed revisions of Chapter 78 to respect environmental rights and to protect natural resources. Those comments also suggest improvements that should be made and recommend specific regulatory text to implement the suggestions. Here we highlight some of the most serious defects in the draft rules.

A. Ecological and Watershed Integrity Demands Better Protection.

The proposed regulations focus exclusively upon on problems arising at a single well site, such sediment and other contaminant releases to water resources. The draft rules do not attempt to address the chronic and cumulatively more serious water pollution, flow disruption, and surface compaction impacts across a watershed from a dispersed industrialization. The proposal also fails to address forest fragmentation or habitat connectivity issues and ignores cumulative impacts of numerous but dispersed Oil and Gas Operations on cover type conversion, edge creation, invasive species, and deforestation. This limited vision guarantees that the proliferation of well sites, access roads, gathering pipelines, and other Oil and Gas Operations will transect and disrupt areas important to continued ecological functioning. Without additional analysis and regulatory safeguards, the Commonwealth will fail to promote sustainable development (to the extent possible with an extractive industry) and to ensure against degradation of the trust.

B. The Chapter 78 Revisions Should Apply to All Oil and Gas Wells.

Many of the regulatory improvements proposed in the draft Chapter 78 rules apply only to wells in unconventional formations, even though *all* wells require land disturbance, produce waste, and otherwise degrade and threaten clean air, pure water, and environmental values. Although Act 13 establishes requirements only for unconventional wells, the statute does not preclude the EQB from extending best practices to conventional wells. Indeed, as trustee for public natural resources, the EQB should require that all oil and gas wells be subject to the strict standards recommended in the attached technical comments. The geologic character of the formation from which oil or gas is extracted, standing alone, does not determine applicable best management practices or constitutionally required safeguards for water, air, and other natural resources. The protections afforded by Chapter 78 thus should depend on the threats to natural resources and the environmental rights and values secured by the Pennsylvania Constitution from modern oil and gas development methods and technologies employed in extraction from either conventional or unconventional formations.

C. Induced Seismicity Requires Study and Analysis.

Induced seismicity can result in environmental and human health impacts identical to those caused by natural earthquakes of similar intensity, including the potential for property damage and injury. Earthquakes may also result in changes to groundwater or surface water level or quality. Seismicity can also compromise wellbore integrity by damaging the cement sheath and metal casing installed as pressure control and ground water protection barriers. Even in the absence of actual damage, induced seismic events can be a nuisance to communities and a source of anxiety; they also may have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed. For these reasons, the EQB, in consultation with the Pennsylvania Geological Survey, should develop regulations requiring an analysis of seismic risk and the potential for induced seismicity.

D. Open Pits, Tanks, and Centralized Impoundments for Oil and Gas Waste and Other Contaminated Fluids Should Be Prohibited.

Open pits and centralized impoundments have the potential to contaminate groundwater and surface water, and many spills, leaks, and other problems involving pits and impoundments have occurred in gas development regions of Pennsylvania. Open pits, tanks, and impoundments can be located very close to homes, exposing nearby residents to toxic emissions. Collecting waste at the drillsite, removing it from pits, and then transporting it by pipeline or truck to a larger open impoundment at a centralized location away from the well site results in additional transfer steps that provide unnecessary opportunities for pollution releases. It also is inefficient from a logistics and energy use standpoint to construct a reserve pit for temporary waste storage and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system for waste collection, because the wastes can be transported directly to a waste handling facility.

Closed-loop tank systems should be used to prevent avoidable spills and to contain volatile materials and wastes, and wherever possible the systems should route captured vapors for use or sale as power. The avoidable degradation or diminution of natural resources is inconsistent with

the EQB's constitutional duty to preserve the public trust corpus. If the EQB rejects this recommendation, and continues to authorize open storage structures, it should adopt the additional regulatory revisions set forth in Appendix A to the technical comments and ensure that the requirements of Chapter 105 apply without exception to centralized impoundments. Moreover, the EQB should ensure that construction of pits and impoundments, in addition to other Oil and Gas Operations requiring land disturbance, are fully covered by the most stringent requirements of Chapter 102. Where Chapter 102 has provided less stringent criteria for oil and gas operations (than for other land disturbance activities), the proposed Chapter 78 regulations should impose additional requirements to address the avoidable degradation of the waters of the Commonwealth.

E. Land Application of Drill Cuttings, Burial of Contaminated Wastes, and Discharge to Land of Contaminated Fluids Should Be Prohibited.

Contaminated oil and gas wastes, including drilling muds and cuttings, that are buried underground or applied to land present an unacceptable risk of contaminating soil and groundwater. Tophole water that has been contaminated by Oil and Gas Operations presents the same risk if it is discharged to land. We oppose the land application not only of all drilling muds and cuttings but also of residual waste. All contaminated drilling muds and cuttings, residual oil and gas wastes, and contaminated fluids, including contaminated tophole water, should be classified, handled, and disposed of as waste.

III. Conclusion

As the Chief Justice stated in his *Robinson Township* opinion: "By any responsible account, the exploitation of the Marcellus Shale Formation will produce a detrimental effect on the environment, on the people, their children, and the future generations, and potentially on the public purse, perhaps rivaling the environmental effects of coal extraction." *Robinson Tp.*, 83 A.3d at 976. For that reason, we appreciate the EQB's effort to improve protections for water, air, and other natural resources in the proposed revisions of Chapter 78. Unfortunately, many of the changes do not go far enough, and some fall short even of requirements in other states. The people of Pennsylvania have a constitutional right to clean air and pure water, which the EQB cannot uphold if it fails to adopt rules governing Oil and Gas Operations that are of proven benefit to the environment and are cost effective for the industry. Nor can the EQB satisfy its obligations as public trustee, if it adopts demonstrably sub-standard regulations that inadequately preserve the trust corpus for the future. We therefore urge you to adopt the improvements to Chapter 78 identified here and explained in detail in our attached technical comments.

Should you have any questions about these comments, you may reach me at 212-845-7377 or at dgoldberg@earthjustice.org.

Respectfully,



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EXHIBIT 1

Technical Comments

**Comments Submitted to the
Pennsylvania Environmental Quality Board
on Proposed Rulemaking
[25 Pa. Code Chapter 78]
Environmental Protection Performance Standards
at Oil and Gas Well Sites**

Prepared with technical, scientific, and regulatory support from:
Harvey Consulting, LLC, Meliora Design, Kevin Heatley, and Briana Mordick.

On behalf of Earthjustice, *et al.*

March 14, 2014

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List of Acronyms

API.....	American Petroleum Institute
APD	A Permit to Drill
Bbl.....	barrel
BMP	Best Management Practices
BLM.....	Bureau of Land Management
COGA	Colorado Oil and Gas Association
CRI.....	Cuttings Reinjection Technology
CWA	Clean Water Act
DOE	Department of Energy
EQB	Environmental Quality Board
ESCP.....	Erosion & Sediment Control Permit
ESCGP	Erosion & Sediment Control General Permit
FTE	Full Time Equivalent
GHG.....	Greenhouse Gases
HAP	Hazardous Air Pollutants
Mcf.....	Thousand cubic feet
MSDS.....	Material Safety Data Sheet
NPDES.....	National Pollutant Discharge Elimination System
NORM	Naturally Occurring Radioactive Material
NYSDEC	New York State Department of Environmental Conservation
P&A	Plug & Abandonment
PA	Pennsylvania
PAH	Polycyclic Aromatic Hydrocarbons
PADEP.....	Pennsylvania Department of Environmental Protection
PCSM.....	Post Construction Storm-water Management
PEMA	Pennsylvania Emergency Management Agency
PNHP	Pennsylvania Natural Heritage Program
PPC	Preparedness, Prevention, and Contingency
SDWA.....	Safe Drinking Water Act
SPR	Spill Prevention Response
SRBC	Susquehanna River Basin Commission
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
TAB	Technical Advisory Board
T&E	Threatened & Endangered
TENORM.....	Technologically Enhanced Naturally Occurring Radioactive Material
TDS.....	Total Dissolved Solids
USDW.....	Underground Sources of Drinking Water
USDOI	United States Department of the Interior
USEPA.....	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC.....	Volatile Organic Compound
WBM	Water-Based Muds
WMP.....	Water Management Plan

Introduction, General Comments, and Principal Concerns

The following comments were prepared with the technical, scientific, and regulatory support of Harvey Consulting, LLC; Meliora Design; Kevin Heatley; and Briana Mordick and are submitted on behalf of Earthjustice and the signatories to the foregoing letter. These comments present recommendations for improving the proposed revisions to 25 Pa. Code Chapter 78, which were issued for public comment by the Pennsylvania Department of Environmental Protection (PADEP) Environmental Quality Board (EQB) in December 2013.

The proposed regulations include a number of beneficial improvements that we support. However, several significant areas must be improved in order to prevent harm to the environment and public health. These comments identify our areas of support and make specific recommendations for improvements.

We respectfully request that the EQB prepare a comprehensive response to these comments, with technical and scientific documentation supporting the response, and provide another 90-day comment period to allow the public an opportunity to evaluate the response and provide additional recommendations before the EQB finalizes the proposed regulations.

1. Public Participation Opportunity

Earthjustice and the other signatories to these comments appreciated the opportunity to participate in meetings with the Technical Advisory Board prior to the EQB's publication of this first draft of the proposed regulations.

We also thank the EQB for the 90-day comment period provided on the large and significant regulatory revision package, as well as the additional public hearings scheduled in locations affected by shale gas development.

2. Ecological and Watershed Integrity

The proposed regulations focus exclusively upon on problems arising at a single well site, such sediment and other contaminant releases to water resources. The draft rules do not attempt to address the chronic and cumulatively more serious water pollution, flow disruption, and surface compaction impacts across a watershed from a dispersed industrialization. The proposal also fails to address forest fragmentation or habitat connectivity issues and ignores cumulative impacts of numerous but dispersed Oil and Gas Operations on cover type conversion, edge creation, invasive species, and deforestation. This limited vision ensures that the proliferation of well sites, access roads, gathering pipelines, and other Oil and Gas Operations will transect and disrupt areas important to continued ecological functioning.

To mitigate the impacts on public natural resources held in trust by the Commonwealth for the benefit of the people, we recommend a number of measures. In particular, we recommend expanding the scope of public natural resources with respect to which information is required in a permit application. We also urge the EQB to require submission and implementation of a detailed restoration plan for every site, to promote sustainable development to the extent possible with an extractive industry and to ensure against degradation of the trust.

3. Applying Best Technology to All Oil and Gas Wells

In several cases, the proposed regulations require industry to use standard best technology and operating practices only for unconventional wells. This means, the more stringent best technology advances would

apply only to natural gas wells drilled and hydraulically fractured into geologic shale formations below the base of the Elk Sandstone. (See § 78.1 for the definition of “unconventional formations.”) The proposed regulations would, in most cases, exclude application of best technology advances for “conventional wells” (oil wells and gas wells that are drilled into shale formations above the base of the Elk Sandstone and oil and gas wells that are drilled into all other geologic formations).

There are currently more than 129,000 conventional wells classified as “active” by the PADEP. Like unconventional wells, conventional wells use chemicals, water resources, disturb land, produce polluting waste, and require reservoir stimulation (including use of hydraulic fracturing in some cases). Conventional wells have also been involved in spills, accidents, and contamination (e.g., from methane migration). Due to the inherent risks involved in all stages of oil and gas development, these requirements should apply to all wells, or the EQB should explain why they do not and provide data and analysis to demonstrate that conventional wells do not carry environmental risks that warrant implementation of an updated, best-practice-based regulatory structure.

4. Induced Seismicity

Induced seismicity can result in environmental and human health impacts identical to those caused by natural earthquakes of similar intensity, including the potential for property damage and injury. Earthquakes may also result in changes to groundwater or surface water level or quality.¹ Seismicity can also compromise wellbore integrity by damaging the cement sheath and metal casing installed as pressure control and ground water protection barriers. Even in the absence of actual damage, induced seismic events can be a nuisance to communities and a source of anxiety; they also may have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed. For these reasons, we recommend that the EQB, in consultation with the Pennsylvania Geological Survey, develop regulations to address induced seismicity. Our reasons for recommending an evaluation of seismic risk and the potential for induced seismicity at a proposed well site, and the scope of the suggested analyses, are set forth in Appendix A.

5. Prohibition of Open Pits, Tanks, and Centralized Impoundments for Contaminated Fluids

Open pits and centralized impoundments have the potential to contaminate groundwater and surface water, and many spills, leaks, and other problems involving pits and impoundments have occurred in gas development regions of Pennsylvania. Open pits, tanks, and impoundments can be located very close to homes, exposing nearby residents to toxic emissions. Collecting waste at the drillsite, removing it from pits, and then transporting it by pipeline or truck to a larger open impoundment at a centralized location away from the well site results in additional transfer steps that provide unnecessary opportunities for pollution releases. It also is inefficient from a logistics and energy use standpoint to construct a reserve pit for temporary waste storage and then remove this pit later. It is substantially more efficient to use a closed-loop tank system for waste collection, because the wastes can be transported directly to a waste handling facility. Closed-loop tank systems should be used to prevent avoidable spills and to contain volatile materials and wastes, and wherever possible the systems should route captured vapors for use or sale as power.

¹ See, e.g. Fleeger, G. M., Goode, D. J., Buckwalter, T. F., & Risser, D. W. (1999). *Hydrologic effects of the Pymatuning earthquake of September 25, 1998, in northwestern Pennsylvania*. US Department of the Interior, US Geological Survey.; King, C. Y., Zhang, W., & Zhang, Z. (2006). Earthquake-induced groundwater and gas changes. *pure and applied geophysics*, 163(4), 633-645.

6. Prohibition of Land Application of Drill Cuttings, Burial of Contaminated Wastes, and Discharge to Land of Contaminated Fluids

Contaminated oil and gas wastes, including drilling muds and cuttings, that are buried underground or applied to land present an unacceptable risk of contaminating soil and groundwater. Tophole water that has been contaminated by Oil and Gas Operations presents the same risk if it is discharged to land, as does brine used for dust control or de-icing. We oppose the land application not only of all drilling muds and cuttings but also of brine and residual waste. All contaminated drilling muds and cuttings, brine, residual oil and gas wastes, and contaminated fluids, including contaminated tophole water, should be classified, handled, and disposed of as waste.

Specific Comments

Specific comments on the proposed regulations are provided below in numeric order. Whenever possible, we endeavored to provide specific revisions to the proposed regulatory language by providing a redlined version of the proposed regulation. Additional new text is shown in **bold underlined red font**. Text that we recommend for deletion has been highlighted in **bold red strikethrough font**.

§ 78.1 Centralized Impoundment Definition

Proposed Regulation: The EQB proposes to add a new definition for “centralized impoundment” that would allow the construction of large, centralized open pits for waste storage. The proposed definition acknowledges that the escape of waste from the impoundment “may result in air, water, or land pollution or endanger persons or property.”

Comment: We oppose the use of centralized impoundments. Centralized impoundments should be prohibited because they are inefficient, cause large-scale surface disturbance, pose a risk of surface and ground water contamination, and contribute to local air pollution. These concerns already have led some companies to transition away from the use of impoundments and pits and toward closed-loop systems.² Wastewater, flowback, and other fluids generated or employed by oil and gas drilling should be contained in closed systems only.

Best practices support the elimination of surface impoundments altogether. Waste collected in tanks at the drillsite and moved by pipeline or truck to be pumped into a larger open impoundment at a centralized location (away from the well site) results in additional unnecessary transportation and transfer steps that provide unnecessary opportunities for pollution releases.

Eliminating use of centralized surface impoundments prevents: large scale surface disturbance that requires multi-year rehabilitation;³ the potential for structural failure and significant pollutant release for centralized impoundments constructed with embankments; the potential for leakage to occur through or around the liner, impacting soil and ground and surface water (a cause of many pollution events in

² See, e.g., ExxonMobil, *2010 Corporate Citizenship Report*, http://cdn.exxonmobil.com/~media/Reports/Corporate%20Citizenship%20Report/2010/community_csr_2010.pdf; Anadarko, *Questions and Answers regarding fracture stimulation*, <https://www.anadarko.com/sitecollectiondocuments/hydraulic%20fracturing/fracQA.pdf>.

³ Surface disturbance is less for temporary tanks than impoundments. Impoundments require surface soil excavation and multi-year rehabilitation. Temporary tanks used at the drillsite use existing gravel space already in place for drilling operations rather than impacting new and additional surface terrain away from the drillsite.

Pennsylvania); hazardous air pollution emissions from evaporation and aeration processes; and, potential exposure of wildlife and domestic animals to the impoundment contents that could be harmful.

The use of large centralized impoundments requires large areas of surface excavation (cut) and embankment placement (fill). The proposed regulation does not include any upper limit on the size or depth of centralized impoundment.

The proposed regulation exempts centralized impoundments of hazard potential 4 and size Category C (up to 40 feet embankment or 1,000 acre-feet of storage) from the regulatory and permitting requirements of Chapter 105, Subchapter B, dam safety and waterway management. The proposed regulation would only require impoundments of 40 feet or greater in depth (Size Category A or B) or hazard potential 1, 2, or 3 to comply with the requirements of Chapter 105. The implications of an impoundment failure or overtopping for a centralized impoundment have all of the same health, safety, and welfare concerns as any other impoundment, with the added concern that the contents of a centralized impoundment can include compounds that are hazardous to both human and ecological health. There was no safety or technical basis provided for the proposed exemption.

If flowback is recycled, it should be subject to strict waste management guidelines, permitting, and trucked or piped from tank-to-tank to another drillsite or used at the same drillsite in a different well.

A centralized surface impoundment photograph in Pennsylvania is shown below.



Bednarski Centralized Waste Impoundment, Pennsylvania, Site Permit PADEP, 798407

The most serious concern with the use of centralized surface impoundments for hydraulic fluid waste (“flowback”) is the amount of hazardous air pollution predicted for these centralized surface impoundments. In 2009, New York State Department of Environmental Conservation (NYSDEC) estimated that each centralized impoundment would be a major source of hazardous air pollution, emitting more than 32.5 tons of air toxins per year, and it was unclear if NYSDEC’s estimate was even a worst-case estimate:

*Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of **32.5 tons** (i.e., “**major**” quantity of HAP) is theoretically possible at a central impoundment⁴ [emphasis added].*

The US Environmental Protection Agency (USEPA) classifies a major source of hazardous air pollution as a source that emits more than 25 tons per year. These centralized impoundments have been sited close to residential homes and community facilities in Pennsylvania, increasing the amount of hazardous air pollution exposure to nearby humans and animals, including increased exposure to benzene, a known human carcinogen.

The proposed definition for “centralized impoundment” (§ 78.1) states that air pollution “may” occur; this is incorrect, air pollution will occur. The amount and type of pollution will depend on the amount and type of waste stored in this open air pit.

We recommend that the proposed definition for “centralized impoundment” be revised and that centralized impoundments be prohibited. Closed-loop tank systems should be required to store and transport waste to prevent the release of substantial amounts of air pollution, particularly hazardous air pollutants to the atmosphere.

With respect to the definition of “centralized impoundment,” we recommend the following changes:

Centralized impoundment—A facility, **prohibited under § 78.59c**, that is:

(i) A natural topographic depression, manmade excavation or diked area formed primarily of earthen materials, **the construction of which causes large-scale surface disturbance.**

(ii) Designed to hold **contaminated** fluids or semifluids associated with oil and gas activities, including wastewater, flowback and mine influenced water, **emissions from or** the escape of which **may will** result in air **pollution, will pose a risk of** water or land pollution, **and may** ~~or~~ endanger persons or property.

(iii) Constructed solely for the purpose of servicing multiple well sites.

§ 78.1 Freshwater and Freshwater Impoundment Definitions

Proposed Regulation: The EQB proposes to add a new definition for “freshwater impoundment” at § 78.1. There is no definition for “freshwater” at § 78.1.

Comment: We support the inclusion of a new definition for a freshwater impoundment. However, it is important to ensure that any “freshwater impoundment” is allowed to actually store only “uncontaminated freshwater” from the Earth’s surface and “uncontaminated fresh groundwater.” The proposed regulation would allow a freshwater impoundment to hold “surface water,” “groundwater” and “other Department approved substances.”

The term “fresh groundwater” is defined at § 78.1 as:

Water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials.

⁴ NYSDEC, *Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program* 6-56 (2009).

We recommend the definition of “fresh groundwater” be modified to clarify that the water must be uncontaminated and include waters protected under the Safe Drinking Water Act (SDWA) as underground sources of drinking water (USDWs). With respect to the definition of “fresh groundwater,” we recommend the following changes:

Fresh groundwater—Uncontaminated water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials and all underground sources of drinking water, as defined in 40 CFR §§ 144.3, 146.4, including all primary and principal aquifers.

We recommend a definition of “fresh surface water” be added as follows:

Fresh surface water—Uncontaminated water in that portion of the generally recognized hydrologic cycle which occupies the surface of the Earth.

A definition for “freshwater” should be added as follows:

Freshwater—fresh surface water or fresh groundwater or both.

It is not clear what “other Department approved sources” might be allowed to be stored in the freshwater impoundment.

We recommend that the clause “other Department approved sources” be deleted unless the EQB can provide clarity on what other “sources” it would allow and explain how it would be safe to store these “other approved sources” with freshwater without contaminating the freshwater. The EQB should provide the name, composition, concentration, and maximum volume of each “other approved source” that would be allowed. The EQB should provide information on the toxicity, biodegradability, and bioaccumulation potential of each “source.” All “sources” that do not meet the definition of “freshwater” (recommended above), that the PADEP currently allows to be stored in open impoundments, should be included in this inventory.

The inclusion of “synthetic liner materials” in the definition of freshwater impoundment is an indication that the material planned for storage in the impoundment could pose a contamination hazard to surface or groundwater if released. Impoundments intended to hold only freshwater that poses no threat to human health are often cost-effectively lined with materials such as clay (bentonite) liners.

The proposed definition for freshwater impoundment states that a freshwater impoundment is a facility that is “not regulated under § 105.3 (relating to scope).” It is unclear what is intended by this clause. Chapter 105.3(a)(2) includes in its scope:

Dams used for the storage of water not located on a watercourse and which have no contributory drainage where the greatest depth of water measured at upstream toe of the dam at maximum storage elevation exceeds 15 feet and the impounding capacity at maximum storage elevation exceeds 50 acre-feet.

This definition would include freshwater impoundments for Oil and Gas Operations that meet the depth and size criteria. Because there is no size limit proposed, there could be freshwater impoundments that exceed the 15 feet and 50 acre-feet threshold. We recommend these freshwater impoundments meet the Chapter 105 requirements or freshwater impoundments be limited to a size below this threshold.

We recommend the definition for “freshwater impoundment” be revised to read:

Freshwater impoundment—A facility that ~~is:~~

- (i) ~~Not Meets the Chapter 105 requirements if~~ regulated under § 105.3 (relating to scope).
- (ii) ~~Is a~~ natural topographic depression, manmade excavation or diked area formed primarily of earthen materials ~~although and~~ lined with synthetic materials.
- (iii) Designed to hold ~~freshwater, fluids, including surface water, groundwater and other Department-approved sources.~~
- (iv) Constructed for the purpose of servicing multiple well sites.

§ 78.1 Inactive Well Status Definition

Proposed Regulation: The regulations at § 78.1 do not include a proposed definition for “inactive well status.”

Comment: We recommend that the following definition be used to clarify what constitutes an inactive well.⁵

Inactive well—**An unplugged well that has been spudded or has been equipped with cemented casing and that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months.**

§ 78.1 Pit Definition

Proposed Regulation: The EQB proposes to add a new definition for “pit” that would allow the storage and ultimate burial of drilling mud and drill cuttings at the well site.

Comment: We oppose the use of pits for long-term storage and the burial of solid waste and other substances at well sites. We also oppose the issuance of waivers to operators for the burial of waste on-site using any “alternate methods” other than those in regulation. Pits can leak and fail, and cause a substantially larger surface impact than temporary tank use. It is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drilling muds and cuttings, and then remove this pit later.

In 2013, the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) Board determined that Pennsylvania’s continued use of production pits poses significant environmental problems. Finding III.4 of the STRONGER Report concluded: “The review team finds that the PADEP’s experience with pits has shown that, although their use is decreasing, many liner failures still occur with pits and other types of waste are being dumped into pits.”⁶

STRONGER recommended that the PADEP “consider adopting regulations or incentives for alternatives to pits used for unconventional wells in order to prevent the threat of pollution to the waters of the

⁵ This definition of inactive well is used in the Texas Administrative Code § 3.15(a)(6).

⁶ STRONGER, *Pennsylvania Follow-up State Review*, Finding III.4 (Sept. 2013), <http://strongerinc.org/sites/all/themes/stronger02/downloads/Final%20Report%20of%20Pennsylvania%20State%20Review%20Approved%20for%20Publication.pdf>.

Commonwealth.”⁷

Our 2014 review of the PADEP pit oversight and inspection practices found that dozens of well files at the PADEP regional offices did not include evidence that the PADEP inspectors are present at the time of pit burial to ensure that the PADEP’s criteria are met. The PADEP confirmed that it does not require operators to perform chemical analysis of waste prior to burial in every instance, nor does the agency keep track of the location or number of buried waste pits. We documented our concerns in an August 12, 2013 letter to the Susquehanna River Basin Commission (SRBC) requesting that they consider an investigation to determine whether Pennsylvania is complying with its obligations as a member jurisdiction to prohibit, control, and abate pollution of the Basin, followed by a January 15, 2014 on the same topic.

Drilling muds and cuttings should not be buried on site due to the risk of surface water and groundwater contamination from leaks that may occur as the pit ages and liners fail over time. Drilling muds and cuttings, gels, cement, and hydraulic fracturing flowback can contain Naturally Occurring Radioactive Material (NORM), Technologically Enhanced Naturally Occurring Radioactive Material (TENORM), mercury, other heavy metals and other harmful chemical additives.

A 2011 Groundwater Protection Council Report found that the leading cause of historical groundwater contamination in Ohio from oil and gas operations was from pit leakage.

During the 25 year study period (1983-2007), Ohio documented 185 groundwater contamination incidents caused by historic or regulated oilfield activities. Of those, 144 groundwater contamination incidents were caused by regulated activities, and 41 incidents resulted from orphaned well leakage. Seventy-six of the incidents caused by regulated activities (52.7 percent) occurred during the first five years of the study (1983-1987). When viewed in five year increments, the number of incidents caused by regulated activities declined significantly (90.1 percent) during the study period. Seventy-eight percent (113) of all documented regulated activity incidents were caused by drilling or production phase activities. **Improper construction or maintenance of reserve pits was the primary source of groundwater contamination, which accounted for 43.8 percent of all regulated activity incidents (63) in Ohio.**

*During the 16 year study period (1993-2008), Texas documented 211 groundwater contamination incidents. More than 35 percent of these incidents (75) resulted from waste management and disposal activities ... [emphasis added].*⁸

It is substantially more efficient to use a closed-loop tank system to collect the drill muds and cuttings and to transport the collected muds and cuttings directly to a waste handling facility permitted to handle contaminated waste.

In 2008, New Mexico instituted a “pit rule,” that banned reserve pits. While some claimed the pit rule would decrease drilling rates, the number of rigs operating in New Mexico increased slightly after the rule was enacted in June 2008. As drilling rig counts dropped across the country in 2009, New Mexico’s rig

⁷*Id.*, Recommendation III.4.

⁸ Groundwater Protection Council, *Groundwater Investigations, and their Role in Advancing Regulatory Reforms. A Two-State Review: Ohio and Texas* (2011).

count only dropped 55% when Texas (who allows pits) dropped more than 62%.⁹ By 2011, as the economy started to rebound, both Texas and New Mexico rebounded to pre-2008 drilling rig counts. Yet,

<u>Cost comparison items</u>	<u>Low</u>	<u>High</u>
Pad construction, liner	\$5,000	\$12,000
Water delivery, cost	\$5,000	\$5,000
Trucking recycled fluid	\$4,000	\$4,000
Solids control equipment rental	\$100,000	\$127,000
Surface handling equipment rental	\$18,000	\$26,000
Mud costs	\$40,000	\$40,000
Re-use solids costs	\$14,000	
Haul and dispose solids		\$50,000
Pad closure, restoration	\$3,000	\$3,000
Total Cost	\$189,000	\$267,000

despite reports of costs savings from individual operators in New Mexico using closed-loop drilling systems, industry worked to overturn the pit rule in 2013. A permit is now required in New Mexico for a pit, and is subject to regulatory requirements at Title 19, Chapter 15, Part 17.

In 2006, Cimarex Energy Co. and M-I SWACO (a drilling contractor) published a paper documenting the equipment required and the cost savings associated with drilling without pits in

New Mexico.¹⁰ The authors concluded that, while additional equipment is needed on the surface to implement closed-loop drilling operations, cost savings can be achieved by eliminating the pit construction and burial costs.

Pitless drilling also provides the added advantage of maintaining low levels of low-gravity solids that can decrease drilling time and reduce non-productive time associated with stuck pipe and loss of circulation and by reducing long-term liability from onsite waste burial and potential pit leakage.

When the pit is eliminated, the costs associated with the pit are eliminated. Mud and mud additive costs and water usage costs are decreased, since fluid usage volume is reduced. However, equipment rental costs are increased for surface handling facilities.

The 2006, Cimarex and M-I SWACO paper showed a cost comparison of drilling with a pit that ranged from \$210,500 to \$447,000 for wells in New Mexico drilled in 2006, as shown in the table to the right.

When the pit was eliminated, costs dropped to \$189,000 to \$267,000 for a cost savings of \$21,500 to \$180,000 per well, as shown in the table here.

The authors concluded: “the results of this analysis indicate that eliminating the pit in New Mexico is cost effective and does not add significant cost to the overall operation. When solids cannot be buried on-site and must be hauled to commercial disposal, eliminating the pit actually saves money.”¹¹

Furthermore, the use of closed-loop, “pit-less” drilling systems is endorsed by the U.S. Bureau of Land Management (BLM) in its 2006 Gold Book of best management practices for drilling on federal lands because such systems prevent soil and water contamination and conserves

<u>Cost comparison items</u>	<u>Low</u>	<u>High</u>
Reserve pit construction, liner	\$31,000	\$54,000
Water delivery, transport and cost	\$13,500	\$18,000
Water haul off, disposal	\$42,000	\$47,000
Mud costs	\$74,000	\$74,000
Pit closure activities	\$50,000	\$104,000
Extra rig time, NPT		\$150,000
Total Cost	\$210,500	\$447,000

⁹ M. Soraghan, *N.M. Is Loosening Drilling Rules, Bucking Trends and Riling Ranchers*, Energy Wire, Nov. 15, 2012.

¹⁰ D. Rogers, *et al.*, *New Innovative Process Allows Drilling without Pits in New Mexico* (2006) (Annual International Petroleum Environmental Conference).

¹¹ *Id.* at 5.

water.¹² Those systems also were determined to be environmentally preferable in 2011.

Use of enclosed tanks and closed loop or semi-closed loop systems is environmentally preferable to the use of open pits and is to be encouraged by the BLM. Open production pits are to be strongly discouraged. Closed tanks and systems minimize waste, entry by wildlife, fugitive emissions that affect air quality, and reduce the risk of soil and groundwater contamination. In addition, the use of tanks instead of pits expedites the ability to complete interim reclamation. Costs may be reduced with the use of tanks, particularly when the pit requires solidification or netting [emphasis added].¹³

Earthworks examined alternatives to pits and documented five cases where operators reported cost savings by using pit-less drilling options.¹⁴

Other drilling contractors report that pit-less drilling results in less surface damage:

*If the surface land is used for growing row crops or other crops for which level ground is important, subsequent subsidence of a reclaimed pit may be a burden to the surface owner. Moreover, many farmers claim to experience a long-term loss of production from the land on which a pit was constructed.*¹⁵

The Colorado Division of Wildlife's¹⁶ list of actions to minimize adverse impacts to wildlife resources includes maximizing the state-of-the-art drilling technology including use of closed-loop "pit-less" drilling technology.

We recommend the definition for "pit" be revised to read:

Pit—A facility, prohibited under §§ 78.56, 78.61, and 78.62, that is:

(i) A natural topographic depression, manmade excavation or diked area formed primarily of earthen materials, which services a single well site and is

(ii) ~~Designed to hold drill cuttings or contaminated~~ fluids, semifluids or solids associated with oil and gas activities, including, but not limited to, ~~fresh water,~~ wastewater, flowback, mine influenced water, and drilling mud ~~and drill cuttings, that services a single well site,~~ emissions from or the escape of which will result in air pollution, will pose a risk of water or land pollution, and may ~~or~~ endanger persons or property.

§ 78.1 Public Water Supply Definition

Proposed Regulation: The EQB proposes to change the definition of a public waters supply as follows:

¹² U.S. Dep't of the Interior (USDOI), BLM, *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development (The Gold Book)* (4th ed. 2006).

¹³ USDOI, BLM, *Management of Oil and Gas Exploration and Production Pits* (Nov. 15, 2011).

¹⁴ Earthworks, *Alternatives to Pits*, http://www.earthworkSACTION.org/issues/detail/alternatives_to_pits#UvIOWsKYapo (last visited Mar. 1, 2014).

¹⁵ Lance Astrella, *Closed Loop Drilling Systems Can Eliminate Reserve Pit Costs*, *Oil & Gas Journal* (May 27, 1996).

¹⁶ Colo. Div. of Wildlife, *Actions to Minimize Adverse Impacts to Wildlife Resources* (Oct. 27, 2008).

Public water supply—[A water system that is subject to the Pennsylvania Safe Drinking Water Act (35 P. S. §§ 721.1—721.17).] A source of water used by a water purveyor.

Comment: We recommend that this definition be revised as follows:

Public water supply—[A water system that is subject to the Pennsylvania Safe Drinking Water Act (35 P. S. §§ 721.1—721.17).] A source of water used by a water purveyor **or for a public water system, as defined in 35 P.S § 721.3.**

§ 78.1 Regional Groundwater Table Definition

Proposed Regulation: The EQB proposes to add a definition of regional groundwater table as follows:

(i) *The fluctuating upper water level surface of an unconfined or confined aquifer where the hydrostatic pressure is equal to the ambient atmospheric pressure.*

(ii) *The term does not include the perched water table or the seasonal high water table.*

Comment: The seasonal high water table should be included as part of the regional groundwater table definition. In Pennsylvania, the unconfined aquifer can fluctuate significantly and this fluctuation is often represented by the seasonal high water table. The seasonal high water table is hydrologically linked to nearby wetlands, springs, and stream systems. Due to the seasonal high water table connectivity to both surface and groundwater, and potential for contamination, Chapter 73 precludes the use of on-site wastewater systems in areas where the seasonal high water table is within 20 inches of the ground surface.

The proposed regulations should recognize the seasonal high water table as a component of the regional groundwater table. Therefore, we recommend the definition for “regional groundwater table” be revised to read:

Regional groundwater table—

(i) **The fluctuating upper water level surface of an unconfined or confined aquifer where the hydrostatic pressure is equal to the ambient atmospheric pressure.**

(ii) **The term does not include the perched water table ~~or the seasonal high water table.~~**

§ 78.1 Regulated Substance Definition

Proposed Regulation: The EQB proposes add a new definition for the term “regulated substance.”

Comment: Because the term regulated substance is used ubiquitously throughout Chapter 78, it would be useful to expand the definition to provide further clarification that regulated substances are hazardous substances and contaminants that require safe handling, storage and disposal methods and equipment. In addition, the current scope of substances covered by the definition is too narrow.

We recommend the definition for “regulated substances” be revised to read:

Regulated substance—Any substance defined as a regulated substance in section 103 of Act 2 (35 P. S. § 6026.103), **which includes hazardous substances and contaminants regulated under the**

Hazardous Sites Cleanup Act, 35 P.S. § 6020.101 et seq.; and pollutants and substances covered by: The Clean Streams Law, 35 P.S. §§ 691.1 et seq.; the Air Pollution Control Act, 35 P.S. §§ 4001 et seq.; the Solid Waste Management Act, 35 P.S. §§ 6018.101 et seq.; the Infectious and Chemotherapeutic Waste Law, 35 P.S. §§ 6019.1 et seq.; the Storage Tank and Spill Prevention Act, 35 P.S. §§ 6021.101 et seq; any waste regulated under the Pennsylvania Low-Level Radioactive Waste Disposal Act of 1988, 35 P.S. §§ 7131.101 et seq.; and any toxic substance or contaminant regulated under federal law, including but not limited to pollutants for which a total maximum daily load may be established under the Clean Water Act, 33 U.S.C. §§ 1251 et seq., and chemicals substances and mixtures for which reports must be submitted under section 8(e) of the Toxic Substances Control Act, 15 U.S.C. §§ 2601 et seq.

§ 78.1 Temporary Pipelines and Gathering Pipeline Definitions

Proposed Regulation: The EQB proposes to add new definitions for the terms “temporary pipelines” and “gathering pipeline.”

Comment: As proposed, the difference between a gathering pipeline and a temporary pipeline is that the gathering pipeline is used to transport hydrocarbons from wells to transmission pipelines, versus the temporary pipelines that are used to transport materials used in construction or stimulation of the oil or gas well or to transport residual waste from the well. The proposed definition for temporary pipelines appears to allow the temporary pipeline to exist until well site reclamation is triggered under § 78.65, nine months later (or 30 days after permit expiration).

Because temporary pipelines are not designed to safely transport hydrocarbons to a transmission pipeline, and these pipelines could potentially be operating at the well site while hydrocarbons are initially produced, the definition should make it clear that temporary pipelines cannot be used to transport hydrocarbons to a transmission line.

We also recommend that either § 78.65 or the definition of temporary pipelines be revised to make clear that these temporary pipelines must be removed within nine months of drilling and completing a well. The proposed requirements at § 78.65 state that drilling supplies and equipment not needed for production must be removed. This regulation should specifically state that temporary pipelines must be removed.

We recommend the definition for “temporary pipelines” be revised to read:

***Temporary pipelines*—Pipelines used for oil and gas operations, including well construction and waste removal, that:**

- (i) Transport materials used for the drilling or hydraulic fracture stimulation, or both, of a well and the residual waste generated as a result of the activities.**
- (ii) Lose functionality after the well site it serviced has been restored under § 78.65 (related to site restoration) and are prohibited from use as gathering pipelines.**

§ 78.1 Water Management Plan Definition

Proposed Regulation: The EQB proposes to add a new definition for the term “Water Management Plan.”

Comment: All oil and gas drilling and hydraulic fracturing operations require the use of water. As proposed by the EQB, a Water Management Plan (WMP) is defined to apply only to a well drilled or completed in an unconventional formation. As defined in § 78.1 an “unconventional formation” would include only natural gas wells drilled and hydraulically fractured into geologic shale formations below the base of the Elk Sandstone. A WMP thus would not be associated with oil wells and all gas wells that are drilled into shale formations above the base of the Elk Sandstone or to oil and gas wells that are drilled into all other geologic formations. WMPs should be defined to apply to the drilling and completion of *all* oil and gas wells.¹⁷

We recommend that the definition of “WMP—Water Management Plan” be revised to read:

WMP—Water Management Plan—A plan associated with drilling or completing **an oil and gas well in an unconventional formation** that demonstrates that the withdrawal and use of water sources protects those sources, as required under law, and protects public health, safety and welfare.

§ 78.1 Water Source Definition

Proposed Regulation: The EQB proposes to add a new definition for the term “Water Source.”

Comment: The “water source” definition precisely tracks 58 Pa.C.S. § 3203, so the problems with the statute are imported into the proposed regulations. All oil and gas drilling and hydraulic fracturing operations require the use of water. The EQB should seek a statutory amendment to define “water source” to include not only water used for drilling or completing a well in an unconventional formation but rather water used for drilling or completing a well in either a conventional or an unconventional formation. In addition, the EQB should ask the legislature to amend the definition to ensure that additives used in drilling or completing a well do not fall within the definition of “water source.”

§ 78.1 Watercourse Definition

Proposed Regulation: The EQB proposes to add a new definition for the term “Watercourse” referencing the existing definition at 25 Pa. Code § 105.1.

Comment: We strongly support consistent use of the watercourse definition at § 105.1 and recommend for clarity that it be spelled out in the new regulations.

Watercourse—The term as defined in **25 Pa. Code § 105.1, namely a channel or conveyance of surface water having defined bed and banks, whether natural or artificial, with perennial or intermittent flow.**

Furthermore, we urge the EQB to use this watercourse definition where stream or other watercourse protection is required in the proposed regulation or in associated guidance documents.

For example, proposed regulation § 78.59c(c)(5) bars construction of centralized impoundments “*within 100 feet measured horizontally from any solid blue line stream, spring or body of water, except wetlands, identified on the most current 7.5 minute quadrangle map of the United States Geological Survey.*” There is no technical or scientifically supported basis or consistent set of standards, however, for the identification of a watercourse as a blue line stream on a 7.5 minute U.S. Geological Survey quadrangle map. Luna Leopold, former Chief Hydrologist of the U.S. Geological Survey (1956-1966), stated that

¹⁷ If the EQB rejects this recommendation, we ask that the EQB respond to the request set forth in Appendix A with respect to the definition of WMPs.

“blue lines do not reflect any statistical characteristics of streamflow occurrence. The specification that the blue line terminate no higher than about 1,000 feet from the watershed divide does not reflect differences in hydrologic performance among various combinations of climate, topography, and geology.”¹⁸ As a result of this practice, many perennial and intermittent streams are not represented as blue lines on 7.5 minute U.S. Geological Survey quadrangle maps.

The definition of watercourse as defined in 25 Pa. Code § 105.1 is a technically accurate definition of stream, and we urge the EQB to eliminate all references to blue-line streams.

§ 78.15(a) Application Requirements – Electronic Permit Application Submission

Proposed Regulation: The EQB proposes that the well permit application be submitted electronically to the PADEP via the website.

Comment: We support electronic submittal of applications to improve processing efficiency. We recommend, however, the following revision to § 78.15(a) to improve transparency to the public and to require that the applicant provide a secure electronic signature on the application, certifying under penalty of perjury that the application contents are true and correct:

(a) An application for a well permit shall be submitted [on forms furnished by the] electronically to the Department through its web site. The permit application shall be made available to the public on the Department’s website on the same day that the Department has determined that the application is complete. The electronic application must and contain the information required by the Department to evaluate the application and must include a secure electronic signature on the application certifying under penalty of perjury that the application contents are true and correct.

§ 78.15(b) Application Requirements – Requirements for Complete Application

Proposed Regulation: The EQB proposes minor changes to § 78.15(b) to conform the rule to the Act. The EQB does not propose to change the requirements for a complete permit application.

Comment: Because the current rules do not require submission of any substantive baseline assessment of the original ecological and soil characteristics of the well site, the site “restoration” required in proposed § 78.65 is largely meaningless. Without such an assessment, the PADEP will have no basis for judging whether the site actually has been restored to its original condition. To provide an empirical basis for that judgment, the applicant should be required to submit a written site restoration plan with studies of baseline conditions sufficient to serve as the benchmark for the site restoration we recommend in our comments on § 78.65. The restoration plan also should identify measures sufficient to restore the site to its original condition. Where such restoration is not possible, the restoration plan should identify measures sufficient to mitigate any remaining adverse effects of the well construction and operation. The burden should be on the applicant to prove any claim that full site restoration is not possible and that proposed mitigation measures will be adequate to compensate for any loss of original features. The permit application should not be considered complete without the restoration plan, and submission of the application should be deemed a commitment to implementing the plan.

¹⁸ Luna B. Leopold, *A View of the River* (Harvard University Press 1994).

We recommend that proposed § 78.15(b) be revised as follows:

(b) The permit application will not be considered complete until the applicant submits a complete and accurate plat, **a site restoration plan including the baseline studies in paragraph (1), the restoration measures in paragraph (2), and the mitigation plan in paragraph (3)**, an approvable bond or other means of complying with section [**215 of the act (58 P. S. § 601.215)] **3225 of the act (relating to bonding)**, the fee in compliance with § 78.19 (relating to permit application fee schedule), proof of the notification **required under section 3211(b.1) of the act (relating to well permits)**, necessary requests for variance or waivers or other documents required to be furnished by law or the Department, **and the information in subsections (c)–(e)**. The person named in the permit shall be the same person named in the bond or other security.**

(1) A site restoration plan shall include studies and photographs documenting the existing contours, drainage patterns, type and density of native plant community, soil characteristics, and habitat of the full footprint of the proposed well site and any area potentially affected by Oil and Gas Operations associated with the proposed well construction and operation. Documentation of existing conditions shall include field data and shall not be based solely upon aerial and/or remote sensing studies. The site restoration plan shall be prepared by a qualified professional ecologist, certified forester, or landscape architect with demonstrated experience in restoration ecology.

(2) A site restoration plan shall include measures that the applicant will implement to restore the contours, drainage patterns, type and density of native plant community, soil characteristics, and habitat of the full footprint of the proposed well site and any area potentially affected by Oil and Gas Operations associated with the proposed well construction and operation to the baseline conditions documented in paragraph (1).

(3) If it is not technically feasible fully to restore the well site and potentially affected area in accordance with paragraph (2), the site restoration plan shall include measures that the applicant will implement to mitigate remaining impacts of Oil and Gas Operations associated with the proposed well construction and operation. The burden shall be on the applicant to prove that full site restoration is not technically feasible and that the proposed mitigation measures will be adequate to compensate for the loss of features that cannot be restored.

§ 78.15(d) Application Requirements – Proof of PNHP Consultation

Proposed Regulation: The EQB proposes to add a new requirement that the applicant provide proof of consultation with the Pennsylvania Natural Heritage Program (“PNHP”), with the goal of protecting threatened or endangered species where the well site or access road is located. If impacts are identified, the EQB proposes working with the applicant to minimize the impacts, without further inclusion of the PNHP in the decision-making process.

Comment: We support the additional consultation requirements with the PNHP. We recommend, however, that the consultation be improved in three ways.

First, the consultation should consider all species of special concern, as defined by the PNHP, not only threatened or endangered (T&E) species.

Second, the examination conducted for purposes of the consultation should include impacts from the full footprint of development, including all areas required for waste handling, processing, pipeline construction, storage, and other activities encompassed in the new proposed definition for “Oil and Gas

Operations.” The newly defined term “Oil and Gas Operations” should be used to make the full scope of the activities within the development footprint clear. The area of analysis also should account for noise, light, and air pollution impacts that reach beyond the immediate footprint of Oil and Gas Operations. When Oil and Gas Operations are located in forest, the area of analysis should extend at least an additional 100 meters (328 feet) from the footprint perimeter of all Oil and Gas Operations to account for edge effects of tree cutting and their potential impacts on migratory birds.¹⁹

Third, the regulations should require more than a standard T&E consultation, which is a minimal, reductionist approach to addressing habitat and forest sustainability. The standard approach is grossly inadequate for protecting forest structure and function, as it makes no attempt to define the spatial parameters of the ecosystem prior to the proposed disturbance. A failure to address pad, road, and gathering line configuration with respect to habitat continuity and connectivity will ensure widespread disruption of ecological processes. The science is clear on this issue, as the species impacts of habitat fragmentation are not specific to oil and gas development. What sets Oil and Gas Operations apart, however, is the dispersed area of build-out. We recommend that the deficiencies in the standard consultation process be cured in these regulations

Finally, PADEP should work with the applicant and PNHP to determine the appropriate mitigation (if any) for impacts that cannot be eliminated or determine when projects cannot be sufficiently mitigated. The regulation should also require that all mitigation measures be included as conditions in the final permit.

We propose the following revisions:

§ 78.15(d) Application Requirements

The applicant shall provide proof of consultation with the Pennsylvania Natural Heritage Program (PNHP) regarding the presence of a State or Federal threatened or endangered species or species of special concern anywhere ~~the proposed well site or access road is located~~ within the full footprint of the Oil and Gas Operations and adjacent area affected by such operations. The area of analysis must account for noise, light, and air pollution impacts that reach beyond the immediate footprint of Oil and Gas Operations. When Oil and Gas Operations are located in forest, the spatial parameters of the ecosystem in existence prior to the proposed disturbance shall define the area of analysis, which also shall extend at least an additional 100 meters (328 feet) from the footprint perimeter of all Oil and Gas Operations, and the analysis shall include a description of impacts on habitat continuity, forest connectivity, patch size, and core forest area.

If the Department determines, based on PNHP data or other sources, that the full footprint of the proposed Oil and Gas Operations well site or access road may adversely impact the species or critical habitat within the appropriately defined ecosystem, the applicant shall consult with the Department and PNHP to avoid or prevent the impact. If the impact cannot be avoided or prevented, the applicant shall demonstrate how the impacts will be minimized in accordance with State and Federal laws pertaining to the protection of threatened or endangered flora and fauna and species of special concern and their habitat by proposing specific mitigation measures for

¹⁹ See K.A. Harper, *et al.*, *Edge Influence on Forest Structure and Composition in Fragmented Landscapes*, 19 *Conserv. Biology* 768–82 (2005); U.S. Geological Survey, *Landscape Consequences of Natural Gas Extraction in Bradford and Washington Counties, Pennsylvania, 2004-2010*, <http://pubs.usgs.gov/of/2012/1154>; Md. Dep’t Natural Res., *Maryland Forest Land Use Assessment*, http://www.dnr.state.md.us/forests/download/sfla_report.pdf.

Department and PNHP consideration. The Department may deny the permit if no acceptable means is available to avoid or mitigate the impact. If avoidance or mitigation methods proposed by the applicant are acceptable to the Department and PNHP, those requirements shall be included as conditions of permit approval.

§ 78.15(e) Application Requirements - PNHP Consultation Exemption

Proposed Regulation: The EQB proposes to exempt applicants from the new requirement at § 78.15(d) to provide proof of consultation with the PNHP if the applicant has submitted an Erosion and Sediment Control Permit Application under 25 Pa. Code § 102.5 and complies with 25 Pa. Code § 102.6(a)(2).

Comment: We do not support the proposed exemption under § 78.15(e), because, existing regulations at Pa. Code § 102.6(a)(2) do not incorporate the changes we have recommended to the proposed regulatory language in § 78.15(d).

Permits issued under Chapter 102 are issued as General Permits under an Erosion and Sediment Control General Permit (ESCGP), specifically permit number ESCGP-2 (and formerly ESCGP-1). Many permit applications are administered at the County Conservation District level, but even those administered at the Department level are not subject to detailed technical review. As a result, many projects that are operating under a ESCGP-1 or ESCGP -2 permit are operating in violation of permit requirements for erosion and sediment control and stormwater management. Since permits issued under § 102 are currently failing to meet the requirements of Chapter 102 for erosion and sediment control and stormwater management, it would be inappropriate to assume that adequate consultation with the PNHP has occurred for purposes of a well permit simply because general permit coverage under Chapter 102 has been obtained. General permit coverage under ESCGP-2 provides no assurance that permit requirements have been met.

We recommend that the PADEP work with the applicant and the PNHP to determine the appropriate mitigation for adverse impacts and require that those mitigation measures be included in the final permit, or if adverse impacts cannot be sufficiently mitigated to deny the permit.

We recommend that § 78.15(e) be deleted in its entirety.

§ 78.15(f) Application Requirements – Impacts to Public Resources

Proposed Regulation: The EQB proposes a process at § 78.15(f) for the PADEP to consider the impacts to public resources when making a determination on a well permit. Proposed § 78.15(f) establishes a 15-day timeframe for applicable jurisdictional agencies to provide comment on projects that come within certain distances of certain public resources.

Comment: We support the proposal to provide public resource agencies with an opportunity comment on any proposed well permit application to ensure public resources are protected. However, the comment period is too short, the potential impact radius proposed around public resources is too small, and the list of public resources is incomplete. We also recommend notice to the government of each locality in which the resources are located. In addition, the requirements of this provision should apply not only to Oil and Gas Operations associated with unconventional wells (shale gas wells drilled below the Elk Sandstone) but also to those associated with conventional wells.

The regulation at § 78.15(f)(1)(I) requires the applicant to notify the applicable resource agency if a well is located “[i]n or within 200 feet of a publicly owned park, forest, game land or wildlife area.” The

examination of impacts to public resources should include impacts from the full footprint of all activities encompassed in the new proposed definition for “Oil and Gas Operations.” The newly defined term “Oil and Gas Operations” should be used to make the full scope of the review obligation clear. Moreover, given that the science of conservation biology indicates that edge impacts (changes in light, moisture, etc.) protrude at least 300 feet into adjacent forest systems, the 200-foot buffer that triggers notification is inadequate and has no basis in either ecological or biological science. We recommend the addition of other public natural resources entitled to protection under Article 1, Section 27, of the Pennsylvania Constitution.

Under § 78.15(f)(2), resource agencies should be given a minimum of 30 business days for comment on permit applications.

We recommend the following proposed revision to § 78.15(f).

§ 78.15 Application Requirements

(f) An applicant proposing to ~~drill a well~~ conduct one or more new Oil and Gas Operations, or to expand one or more existing Oil and Gas Operations (including but not limited to well drilling) at a location listed in paragraph (1) shall notify the applicable resource agency, if any, in accordance with paragraph (2) and provide the information in paragraph (3) to the Department in the well permit application.

(1) This subsection applies if ~~the proposed surface location of the well~~ any portion of the surface footprint of a new Oil and Gas Operation, or an expansion to an existing Oil and Gas Operation is located:

(i) In or within ~~200 feet~~ ½ mile (2,640 feet) of a publicly owned park, forest, game land or wildlife area.

(ii) In, ~~within,~~ or within ~~view of~~ the corridor of State or National ~~wild or~~ scenic rivers.

(iii) Within ~~200 feet~~ ¼ mile (1,320 feet) of a National natural landmark.

(iv) In a location that will impact other critical communities. For the purposes of this subparagraph, other critical communities means special concern species, High Quality or Exceptional Value Waters, national recreational areas, or lands within the boundaries of the National Wildlife Refuge System, the National System of Trails, or the National Wilderness Preservation System.

(v) Within ~~200 feet~~ ¼ mile (1,320 feet) of a historical or archeological site listed on the Federal or State list of historic places.

(vi) ~~In the case of an unconventional well,~~ Within ~~4,000~~ 1,000 feet of a water well, surface water intake, reservoir or other water supply extraction point used by a water purveyor or a storm drain that discharges to within 4,000 of any of the above.

(2) The applicant shall notify the public resource agency responsible for managing the public resource identified in paragraph (1), if any. The applicant shall forward by certified mail a copy of the plat identifying the proposed location of the full footprint of the new Oil and Gas Operation, or expansion to an existing Oil and Gas Operation ~~well, well site and access road~~ and information in paragraph (3) to the public resource agency at least ~~15 days~~ 30 business days prior to submitting its well permit application to the Department. The applicant shall submit proof of notification with the well permit application. From the date of notification, the public resource agency has ~~15 days~~ 30 business days to provide written comments to the Department and the applicant on the functions

and uses of the public resource and the measures, if any, that the public resource agency recommends the Department consider to avoid or minimize probable harmful impacts to the public resource where the new or expanded Oil and Gas Operation-well, well-site and access road is located. The applicant ~~may~~ **must** provide a response to the Department to the comments adopting the mitigation measures proposed by the public resource agency or proposing equally or more protective alternative measures.

(3) After the public resource agency comment period is complete, the applicant shall include the following information in the well permit application on forms provided by the Department and submit the forms with the well permit application in accordance with § 75.15(a):

- (i) An identification of the public resource.**
- (ii) A description of the functions and uses of the public resource.**
- (iii) A description of the measures proposed to be taken to avoid or mitigate impacts, if any.**
- (iv) Proof that the public resource agency was notified and provided 30 business days to comment.**
- (iv) A copy of the public resource agencies comments, and a response to each comment.**

(4) The information required in paragraph (3) shall ~~be limited to the discrete area of~~ include any portion of the public resource that may be affected by full footprint of the new Oil and Gas Operation, or an expansion of an existing Oil and Gas Operation-operation (including the well) well site and access road.

§ 78.15(g) Application Requirements – Department Decision on Public Resource Impact

Proposed Regulation: The EQB proposes a process at § 78.15(g) for the PADEP to consider the impacts to public resources when making a determination on a well permit. The proposed regulation at § 78.15(g) authorizes the PADEP to include conditions in the well permit to avoid or mitigate impacts.

Comment: We support the PADEP’S ability to include conditions in the well permit to avoid or mitigate harmful impacts to public resources. However, the PADEP should be required to include permit conditions to avoid potentially adverse impacts, and if avoidance is not possible, to mitigate such impacts on the public resource. If adequate avoidance or mitigation cannot be implemented, the PADEP should deny the permit application as authorized under 58 Pa. C.S. § 3211(e.1)(1).

The regulation should take into account the full footprint of the proposed development (including, but not limited to the proposed well site, waste handling facilities, processing facilities, pipeline routes, storage areas, and access road), using the newly defined term “Oil and Gas Operations.”

The proposed regulation socializes costs while privatizing profits by imposing the burden of proof on the PADEP to justify permit conditions. The applicant should have the burden of proof in any proceeding challenging either permit conditions imposed by the PADEP in an effort to avoid or mitigate adverse impacts on public natural resources or the denial of a permit.

We recommend the following proposed revision to § 78.15(g).

§ 78.15 Application Requirements

(g) If any portion of the proposed footprint of a new or expanded Oil and Gas Operation well, well site or access road poses a probable potentially significant harmful impact to a public resource, the Department may shall include conditions in the well permit to avoid or mitigate those impacts to the public resource's current functions and uses and shall deny the permit if necessary to assure compliance with any law administered by the Department. The Department will consider the impact of any potential permit condition on the applicant's ability to exercise its property rights with regard to the development of oil and gas resources and the degree to which any potential condition may impact or impede the optimal development of the oil and gas resources. However, the Department shall not approve permits without conditions reasonably calculated to avoid or mitigate potentially significant harmful impacts on public resources.

The issuance of a permit containing conditions imposed by the Department under this subsection is an action that is appealable to the Environmental Hearing Board. The Department applicant has the burden of proving that the Department's decision to impose conditions were necessary to protect against a probable harmful impact ofn the public resource or to deny a permit was arbitrary and capricious, an abuse of discretion, or contrary to law.

§§ 78.17 and 78.19 Permit Application Fee Schedule

Proposed Regulation: The EQB proposes revisions to § 78.17 and § 78.19 for permit application fee schedules.

Comment: The PADEP's application fee schedule for conventional wells varies based on well depth, from \$250 to \$1,950 for conventional wells and \$900 to \$3,000 for unconventional wells. The proposed fee schedules, and explanatory information preceding the proposed rule do not explain how the EQB developed the fee amounts, or how these amounts bear a reasonable relationship to the cost of administering § 78 permits as required by the statute (58 Pa. C.S. § 3211(d)).

(58 Pa. C.S. § 3211(d)) Permit fee.--Each application for a well permit shall be accompanied by a permit fee, established by the Environmental Quality Board, which bears a reasonable relationship to the cost of administering this chapter.

We request that the EQB provide justification for each fee schedule to ensure that there are sufficient funds to hire and retain qualified professional staff to process the permits, hire experts, conduct site inspections, and ensure compliance. More specifically, we request that the EQB provide information to show the number of full time equivalent (FTE) professionals (by discipline) needed to carefully review each permit application, hire experts when needed, and cover the cost of pre-application site visits, and ensure compliance once the permit is issued. The cost of that review should be divided by the average number of permits processed each year.

The process and cost to amend a permit should be clarified.

Please also explain if the permit processing fee includes funds for inspection and enforcement, or how those funds are provided to ensure adequate funds and personnel are in place to implement the compliance program.

By comparison, in 2009, the BLM increased its well permit application fee from \$4,000 per well to \$6,500 per well after reviewing the cost just to review and issue A Permit to Drill (APD).²⁰

§ 78.51 Protection of Water Supplies

Proposed Regulation: The EQB proposes to update § 78.51 to add additional water supply protections authorized in Act 13 (58 Pa. C.S. § 3218).

Comment: We support regulatory improvements for water supply protection; however, we are concerned that the proposed regulatory language is insufficient to protect the health of residents who may be adversely affected by contamination of water supplies and that the proposed regulation conflicts with the statute at 58 Pa. C.S. § 3218.

58 Pa. C.S. § 3218 Protection of Water Supplies requires the operator to restore water quality at least to the standards established under the Pennsylvania Safe Drinking Water Act, or to a higher standard if the water quality exceeded the Pennsylvania Safe Drinking Water Act standards before the pollution occurred:

(a) General rule. --In addition to the requirements of subsection (c.1), a well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity or quality for the purposes served by the supply. The department shall ensure that the quality of a restored or replaced water supply meets the standards established under the act of May 1, 1984 (P.L.206, No.43), known as the Pennsylvania Safe Drinking Water Act, or is comparable to the quality of the water supply before it was affected by the operator if that water supply exceeded those standards. The Environmental Quality Board shall promulgate regulations necessary to meet the requirements of this subsection [emphasis added].

Under no circumstances should the PADEP allow an operator to restore a water supply to a drinking water quality that does not meet the Pennsylvania Safe Drinking Water Act standards.

Furthermore, the majority of documented water quality violations are related to PADEP or Conservation District issued notices related to erosion and sediment control. There is no basis to exempt these construction activities from requirements to protect water supply.

We recommend the following proposed revisions to § 78.51(c) and (d).

§ 78.51. Protection of water supplies.

* * * * *

(c) Within 10 **calendar** days of the receipt of the investigation request, the Department will investigate the claim and will, within 45 **calendar** days of receipt of the request, make a determination. If the Department finds that pollution or diminution was caused by the well site construction, drilling, alteration or operation activities or if it presumes the well operator responsible for polluting the water supply of the

²⁰ USDOJ, BLM, *BLM Will Collect \$6,500 Processing Fee for Each New Oil and Gas Drilling Permit Application* (Nov. 4, 2009), http://www.blm.gov/wo/st/en/info/newsroom/2009/november/NR_11_04_2009.html (press release).

landowner or water purveyor under section [208(c) of the act (58 P. S. § 601.208(c))] 3218(c) of the act (relating to protection of water supplies), the Department will issue orders to the well operator necessary to assure compliance with this section. ~~The presumption established by section 3218(e) of the act is not applicable to pollution resulting from well site construction.~~

(d) A restored or replaced water supply includes any well, spring, public water system or other water supply approved by the Department, which meets the criteria for adequacy as follows:

* * * * *

(2) Quality. The quality of a restored or replaced water supply will be deemed adequate if it meets the standards established under the Pennsylvania Safe Drinking Water Act (35 P. S. §§ 721.1—721.17). ~~or is comparable to the quality of the water supply before it was affected by the operator if that water supply [did not meet these] exceeded those standards. If, prior to pollution, a water supply was of a higher quality than required under Pennsylvania Safe Drinking Water Act standards, the restored or replaced water supply shall meet the pre-pollution quality of the water. In no case shall the quality of the water supplied for restoration or replacement of water polluted by the operator fall below the quality of the water supply that existed before the pollution occurred.~~

§ 78.52 Predrilling or Prealteration Survey

Proposed Regulation: The EQB proposes to revise § 78.52 to require sample results to be provided to the PADEP and water users within 10 days, and require notification that the presumption under 58 Pa. C.S. § 3218(d)(1)(ii) and (2)(ii) of the Act may be void if the landowner or water purveyor refuses to allow the water sampling.

Comment: We support regulatory improvements for water supply protection, sampling, and notification. However, we are concerned that while the proposed regulation at § 78.52 requires a predrilling or prealteration survey (water sampling) and testing by an independent Pennsylvania-accredited laboratory, it does not specify what tests must be run by the lab. The regulation also does not specify a minimum radius of investigation for the survey work.

We recommend that the proposed regulation be revised to include a comprehensive, specific list of tests to be performed in order to collect the data needed to verify if contamination from Oil and Gas Operations occurred. The regulation should also make it clear that the PADEP will follow the same recommendations issued to operators when it conducts testing in response to homeowner complaints and subsequent investigations. We recommend that the lab test for specific common oil and gas operational chemicals and pollutants, for the additives planned for use in hydraulic fracturing fluids, toxic volatiles (benzene, toluene, xylenes), the components of natural gas (e.g., methane, ethane) and toxic volatiles from the formation water (benzene, toluene, xylenes), salts and relevant inorganic contaminants.²¹

Table 1 below compares the list of contaminants potentially linked to hydraulic fracturing found in groundwater near Pavillion Wyoming,²² with test parameters recommended by the Colorado Oil and Gas

²¹ If the EQB rejects this recommendation, we ask that the EQB respond to the request set forth in Appendix A with respect to Abandoned and Orphaned Well Identification.

²² D.C. DiGiulio, *et al.*, USEPA, Office of Research and Development, *DRAFT: Investigation of Ground Water Contamination near Pavillion, Wyoming.*, Ada, OK (2011).

Association (COGA)²³, and test parameters recommended by the New York State Department of Environmental Conservation (NYSDEC) in their proposed regulations at 6 NYCRR § 560.5(d)(1).

Each of the parameters listed on the following page should be mandatory minimum testing requirements.

Table 1: The three columns indicate whether the constituent was either elevated or detected at Pavillion WY (DiGuilio et al 2011), recommended for sampling by COGA (2011), or recommended by NYSDEC in proposed 6 NYCRR § 560.5(d)(1).			
Constituent	Elevated concentration or detectable at Pavillion	COGA Listed	NYSDEC
pH	X	X	X
Specific conductance	X	X	X
Total Dissolved Solids		X	X
Alkalinity	X	X	
Bromide		X	
Barium			X (2)
Chloride		X	X
Sulfate		X	
Nitrate and nitrite (N)		X	
Phosphorus		X	
Arsenic	(1)		(2)
Boron		X	
Calcium		X	
Iron		X	X
Magnesium		X	
Manganese		X	X
Potassium	X	X	
Selenium		X	
Sodium		X	X
Strontium		X	
Gross alpha/beta			X
Methane	X	X	X
Ethane	X	X	X
Propane	X	X	
Benzene	X	X	X
Toluene	X	X	X
Ethylbenzene	X	X	X
Xylene	X	X	X
Trimethylbenzenes	X		
Isopropanol	X		
Diethylene glycol	X		
Triethylene glycol	X		
Tert-butyl alcohol	X		
Gasoline range organics	X		
Diesel range organics	X		
Naphthalene	X		
(1) Arsenic was noted in drilling fluids at Pavillion and was detected but not an exceedance in groundwater.			
(2) Arsenic and barium were found in wells at Dimock, PA ²⁴			

²³ Colorado Oil and Gas Association (COGA), *Voluntary Baseline Groundwater Quality Sampling Program, Example Sampling and Analysis Plan* (2011) (developed in cooperation with the Colorado Oil and Gas Conservation Commission).

²⁴ Memorandum from Richard M. Fetzer, Eastern Response Branch, to Dennis P Carney, Hazardous Site Cleanup Division, *Request for Funding for a Removal Action at the Dimock Residential Groundwater Site, Intersection of PA Routs 29 and 2024, Dimock Township, Susquehanna County, Pennsylvania* (Jan. 19, 2012).

Sampling measured exclusively from the vertical portion of the well does not account for the potential for contamination from the horizontal wellbore. For example, significantly higher methane concentrations have been found in water wells within a kilometer (0.62 miles) from Marcellus wells.²⁵ Additionally, vertical movement of fluids is possible from the area of the shale that receives a hydraulic fracturing treatment, and eventually, all wells that lie above developed gas plays may have a potential for contamination.

Therefore, we recommend that the operator sample all wells and springs within at least one mile from the edge of the well pad or a minimum of 1,000' from any point along the horizontal wellbore, whichever is greater. The analysis must account for the movement of gas as well as fluids. Although these distances exceed the 2,500' distance for purposes of applying the statutory presumption, the additional sampling is essential to building scientific understanding of affected resources in oil and gas development areas and to inform future statutory changes to pre-drilling requirements, particularly as emerging research indicates that contaminants move greater distances than previously assumed.

We recommend the following proposed revision to § 78.52(c).

§ 78.52. Predrilling or prealteration survey.

* * * * *

(c) The survey shall be conducted by an independent **[certified] Pennsylvania-accredited** laboratory. A person independent of the well owner or well operator, other than an employee of the **[certified] accredited** laboratory, may collect the sample and document the condition of the water supply, if the **[certified] accredited** laboratory affirms that the sampling and documentation is performed in accordance with the laboratory's approved sample collection, preservation and handling procedure and chain of custody.

(1) The following list of sample data must be collected and laboratory test parameters must be evaluated by a Pennsylvania-accredited laboratory: static water level (when possible) pH, specific conductance, total dissolved solids (TDS), alkalinity, bromide, barium, chloride, sulfate, nitrate and nitrite (N), phosphorus, arsenic, boron, calcium, iron, magnesium, manganese, potassium, selenium, sodium, strontium, gross alpha/beta, methane, ethane, propane, benzene, toluene, ethylbenzene, xylene, trimethylbenzenes, Isopropanol, diethylene glycol, triethylene glycol, tert-butyl alcohol, gasoline range organics, diesel range organics, naphthalene and other polycyclic aromatic hydrocarbons (PAHs), and all other chemicals planned to be used in hydraulic fracturing operations or drilling. The Department may require additional sample data to be collected and additional lab tests to be run. The Department shall follow these survey requirements when conducting follow up testing in response to complaints of diminution of water quality or quantity and in its subsequent investigations.

(2) Prior to site disturbance for a new well or new spud for an existing Oil and Gas Operation, the owner or operator must make all reasonable attempts, with the landowner's permission, to sample and test, at the owner's or operator's expense, all water wells, domestic supply springs, and water wells and springs that are used as water supply for livestock or crops, that are within one mile from the edge of the well pad or a minimum of 1,000' from any point along the horizontal wellbore, whichever is greater.

²⁵ S.G. Osborn, *et al.*, *Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing*, Proc. of the Nat'l Academy of Sciences pnas:1100682108 (2011).

§ 78.52a Abandoned and Orphaned Well Identification

Proposed Regulation: The EQB proposes a process at § 78.52a that requires well operators to identify orphaned and improperly abandoned wells prior to hydraulic fracturing operations.

Comment: We support the requirement for well operators to identify orphaned and improperly abandoned wells prior to hydraulic fracturing operations. It is estimated that there are approximately 200,000 improperly abandoned or orphaned wells in Pennsylvania.²⁶

We recommend that the requirement to identify orphaned and improperly abandoned wells be expanded to include identification prior to all oil and gas drilling operations, including but not limited to site disturbance, drilling, and construction.

Improperly abandoned wells include wells that have not been abandoned in compliance with the PADEP's requirements for long-term plugging and abandonment at 25 Pa. Code § 78.91 through § 78.98. An improperly abandoned well could include a well that was plugged and abandoned (P&A'd), but was done so in a manner where the well still poses a risk to the environment (e.g., insufficient barriers or cement used to seal the well). Because operators typically do not monitor the condition of P&A'd wells, improperly abandoned wells often go un-resolved.

Well construction standards, techniques, and technology have improved over time, and it is reasonable to assume that most of these long-term idle wells were not constructed to today's standards, have been subject to mechanical wear and corrosion, and warrant proper abandonment to mitigate risk to protected groundwater resources. To compound problems, many wells that have not been properly abandoned do not have financial security (e.g., bonds) in place, or have insufficient bond amounts set aside, to fund P&A work.

The number of improperly abandoned wells in Pennsylvania is a significant issue as new wells are constructed and existing wells are hydraulically fractured or re-drilled to optimize production. These old wells could provide a vertical conduit for pollutants to reach protected aquifers. Wells drilled and fracture stimulated nearby pose a risk of communicating with the improperly abandoned or orphaned well. For example, a hydraulic fracture treatment can propagate a fracture that, depending on geology, design, and well depths, could pose a risk of intersection with a nearby well (e.g., active producer, abandoned or orphaned well). This type of well-to-well communication is typically referred to in industry publications as a "frac-hit."

Improperly abandoned wells (including improperly abandoned orphaned wells) pose a risk to the environment. Wellbore infrastructure can corrode and erode, failing over time and creating a potential pollutant pathway for hydrocarbons to move vertically through failed casing or cement to groundwater resources. These wells can either leak gas on their own or provide a vertical pollutant pathway to groundwater resources that can be activated by new well activity nearby.

Pollution caused by improperly abandoned wells in Pennsylvania was documented in a 2009 report prepared by the PADEP. The PADEP report listed 27 cases where improperly abandoned wells have been

²⁶ Scott Detrow, *Perilous Pathways: Behind the Staggering Number of Abandoned Wells in Pennsylvania*, StateImpact (Oct. 10, 2012), <http://stateimpact.npr.org/pennsylvania/2012/10/10/perilous-pathways-behind-the-staggering-number-of-abandoned-wells-in-pennsylvania>.

the source of groundwater contamination.²⁷ In some of the 27 cases the wells were abandoned according to the standard practices of the time, but now leak and need to be re-abandoned using improved materials and techniques. Some of the cases cited by the PADEP include very old well construction techniques, for example, surface casing made out of wood that has rotted away, and wells with no surface casing or cement installed at all. These wells have provided a conduit for gas and other pollutants to reach groundwater through damaged or worn casing, poorly installed cement, or more directly where casing or cement was not initially installed.

The PADEP also identified wells that need to be P&A'd, but have not yet been addressed due to the lack of a responsible party and/or on account of the PADEP resource limitations.²⁸

There were three cases cited by the PADEP where fracture stimulations in an operating well communicated with a nearby abandoned well, causing a gas leak in the abandoned well.²⁹ The PADEP's study highlighted the importance of locating orphaned and improperly abandoned wells near new oil and gas developments, and showed the importance of properly abandoning wells before new development proceeds.

A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. The study found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.³⁰ Clearly, the higher incidence rate of methane contamination in drinking water wells in shale gas extraction areas is not a coincidence, but is an indicator of shale gas drilling and completion operations mobilizing gas from the shale gas reservoir into protected aquifers. One of the most likely pathways for leaking of gas mobilized by a hydraulic fracture treatment is a nearby existing well that either was improperly constructed or improperly plugged. Given their failed cement, corroded casing, or lack of casing or cement, such improperly abandoned wells present vertical pathways to aquifers and drinking water resources.

Mechanical failure, human error, and engineering design flaws do occur in the construction and operation of wells. Indeed, groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

Pennsylvania has found that significant planning, research, and field work is needed to identify orphaned and improperly abandoned wells before drilling nearby wells; such aspects must be integrated into the proposed regulations to guide operator identification of abandoned wells. At a 2009 Stray Gas Workshop in Pennsylvania, Garrett Velosi, from the National Energy Technology Laboratory, pointed out that one of the main problems with stray gas leaks from abandoned wells is verifying the location of improperly abandoned wells. Records on older wells are often limited or non-existent. Mr. Velosi presented methods

²⁷ PADEP, Bureau of Oil and Gas Management, *Stray Natural Gas Migration Associated with Oil and Gas Wells* (Draft Oct. 28, 2009).

²⁸ *See id.* Cases include: Independent Valley News Migration, Allegheny County – SWRO – March 2009; Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008; Childers Migration, Washington County – SWRO – June 2005; Groshek Migration, Keating Twp., McKean County – NWRO – 2008; and Skinner Migration, Columbus Twp., Warren County – NWRO.

²⁹ *See id.*

³⁰ S.G. Osborn, *et al.*, *Methane Contamination of Drinking Water Accompanying Gas Well Drilling and Hydraulic Fracturing*, Proc. of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, p.2 (2011).

for locating unmarked abandoned wells. They include the use of historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).³¹

Additionally, we are concerned that the proposed radius of investigation for locating improperly abandoned wells is too small, and that action is not required to properly abandon a well that could be intersected by a hydraulic fracture treatment.

The EQB proposed a radius of investigation of 1,000 feet for all gas wells (that produce marketable quantities of gas or a gas/oil ratio of more than 100 Mcf/bbl). The EQB did not explain how it determined a 1,000 feet threshold to be sufficient and protective of ground water resources. Nor did the EQB explain why it proposes to exempt all gas wells that do not produce marketable quantities of gas or a gas/oil ratio of less than 100 Mcf/bbl from the operator's obligation to identify orphaned and abandoned wells prior to hydraulic fracturing operations.

The amount of gas a well can actually produce will depend on the success of the hydraulic fracture treatment. This information will not be known until after the hydraulic fracture treatment is completed. Therefore, decision criteria based on data that will not be available at the time the decision is made are not good criteria to use to determine whether abandoned and orphaned wells must be identified prior to a hydraulic fracture treatment.

We are also concerned that, in addition to gas that may be mobilized with the hydraulic fracture treatment, that the chemicals contained in the hydraulic fracture treatment itself have the potential to intersect an abandoned or orphaned well and result in ground water contamination. Therefore, the need to identify abandoned or orphaned in the hydraulic fracture treatment radius is independent of the gas flow rate.

The EQB proposed a radius of investigation of 1,000 feet for all horizontally drilled oil wells and 500 feet for vertically drilled oil wells. The EQB did not explain how it determined the 500 and 1,000 feet thresholds to be sufficient and protective of ground water resources.

As proposed by the EQB, there is no variability in the impact radii to account for hydraulic fracture treatment type or size variation. Fracture zones can propagate at considerable distances from the wellbore, and the EQB should require operators to identify abandoned wells within the potential zone of impact, with an additional margin of safety.

We recommend that operators be required to identify any improperly abandoned wells within 2,500 feet of the furthest fracture zone extent measured along the entire wellbore. This method will ensure a larger radius of investigation is completed for larger hydraulic fracture treatments with larger radii of impact.

Additionally, we recommend that operators that have not properly P&A'd all their wells in Pennsylvania be required to complete that work before being issued permits to drill and hydraulically fracture new wells. It is not acceptable for operators to continue to drill new wells without taking responsibility for remedying existing problem wells. Pennsylvania law provides the PADEP with the authority to deny a permit if issuance of the permit would result in a violation of applicable law. 58 Pa. C.S. § 3211(e)(1). Failure to plug and abandon wells would be a violation of applicable law 58 Pa. C.S. § 3220.

³¹ G. Veloski, National Energy Technology Laboratory, *Methods for Locating Wells in Urban Areas – A Summary of Case Studies* (Nov. 2009) (Pennsylvania Stray Gas Workshop).

Additionally, regulations should clarify that operators applying for a permit to drill a new well nearby an improperly P&A'd or orphaned well must either: (1) locate the well's owner and arrange for the well to be P&A'd consistent with the PADEP's regulations; (2) work with the PADEP to use the PADEP's Well Plugging Funds (58 Pa. C.S. § 3271) to properly P&A each improperly abandoned well identified; or (3) if the PADEP has insufficient funds to complete this work on the time schedule and the operator wants to implement its project at a faster pace, the operator should be required P&A the improperly abandoned well before the PADEP issues any site construction or drilling permits.

New wells drilled and hydraulically fractured near improperly P&A'd wells can result in groundwater contamination. It is not acceptable to defer resolution of improperly P&A'd wells to a future, yet-to-be-determined process with an unknown outcome, and proceed with approval of new wells, when those defective wells are located within the potential hydraulic fracture treatment zone of impact.³²

We also recommend that where current and accurate records are not available, that the operator be required to conduct aeromagnetic and ground magnetic surveys and use methane detectors to identify those wells, consistent with abandoned well location method recommendations from the U.S. Geological Survey (USGS).³³

A report of these investigations shall be filed with the PADEP within 7 days and the PADEP shall make this information available on a publicly available database.

We recommend the following proposed revision to § 78.52a (a), (b) and (c):

§ 78.52a. Abandoned and orphaned well identification.

(a) Prior to site construction and drilling or hydraulically fracturing ~~a the~~ well, the operator of a gas well or ~~horizontal~~ oil well shall identify the location of orphaned or abandoned wells or improperly abandoned wells within 1,000 feet measured within 2,500 feet of the vertical wellbore, measured horizontally, and within 2,500 feet of the horizontal wellbore, measured from the surface directly above its entire length, or in in the case that the well is hydraulically fractured, within 2,500 feet of the furthest predicted fracture zone extent measured along the length of a horizontal the entire well bore in accordance with subsection (b). Prior to hydraulically fracturing the well, the operator of a vertical oil well shall identify the location of orphaned or abandoned wells within 500 feet of the well bore in accordance with subsection (b). For the purposes of this section, a gas well is a well which is producing or capable of producing marketable quantities of gas or of gas and oil with a gas-oil ratio of more than 100 MCF per bbl of oil.

(b) Identification shall be accomplished by ~~conducting the following the steps required in (1) through (6), submitting a report documenting this work, and submitting the survey results within seven days of completion. The Department shall make this survey work publically available on its website within 7 days of receipt.~~

(1) A review of the Department's active, inactive, plugged, orphaned and abandoned well database.

³² In its 2010 *Pennsylvania Hydraulic Fracturing Review*, STRONGER recommended that the Department take action to "eliminate potential pathways for fluid movement into groundwater..." and consider situations in which active and abandoned wells located near fracking operations will "...provide pathways for fluid movement into groundwater," with a goal of preventing communication between wells.

³³ U.S. Geological Survey (USGS), Fact Sheet 163-95, *Magnetic Surveys for Locating Abandoned Wells*, <http://pubs.usgs.gov/fs/fs-0163-95/FS163-95.html>.

(2) A review of applicable farm line maps made available on the Department website, where accessible.

(3) Submitting a questionnaire on forms provided by the Department to landowners whose property is within the area identified in subsection (a) regarding the precise location of orphaned and abandoned wells on their property.

(4) A review of historical air photos.

(5) A field survey that includes a ground survey to identify surface evidence of orphaned, abandoned, or improperly abandoned wells, including the use of methane detection equipment.

(6) Aeromagnetic and ground magnetic surveys.

(c) Prior to obtaining a permit for site construction or to drill or hydraulically fracturing a well, the operator shall:

(1) Provide evidence to the Department that all the wells it is financially responsible for in Pennsylvania either are producing or have been properly P&A'd in accordance with 58 Pa. C.S. § 3220 and the Department's requirements for long-term plugging and abandonment.

(2) Submit a plat to the Department showing the location and GPS coordinates of orphaned and abandoned wells identified under subsection (b) and proof of notification that the operators submitted questionnaires under subsection (b)(3).

(3) Provide evidence to the Department that, for each orphaned or abandoned well identified, the well's owner was located, and the well owner has properly P&A'd the well according to the Department's requirements for long-term plugging and abandonment or,

(A) The well owner cannot be located or will not properly P&A the well and that the Department's Well Plugging Funds (58 Pa. C.S. § 3271) have been used to properly P&A each well, according to the Department's requirements for long-term plugging and abandonment, or

(B) The operator has properly P&A'd the well according to the Department's requirements for long term plugging and abandonment.

(d) The Department will include any new orphaned and abandoned well data into its well database, within 30 calendar days, and make that data publically available on the Department's website.

§ 78.53 Erosion and Sediment Control

Proposed Regulation: The EQB proposes limited narrative changes for erosion and sediment control but does not include any substantive content changes at § 78.53. Narrative changes include removal of a direct reference to the preparation of an Erosion and Sediment Control plan (which is required under § 102) and reference to the March 2012 Erosion and Sediment Pollution Control Manual (Erosion and Sediment Pollution Control Program Manual, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 363-2134-008) and the 2001 Oil and Gas Management Practices (Oil and Gas Operators Manual, Commonwealth of Pennsylvania, Department of Environmental Protection, Guidance No. 550-0300-001).

Comment: Since passage of legislation in 2005, the federal Clean Water Act exempted most stormwater discharges associated with oil and gas construction activities from permitting requirements under the National Pollutant Discharge Elimination System (NPDES) program. The PADEP has established a state-

specific regulatory program for such discharges under the Pennsylvania Clean Streams Law. The centerpiece of this program is the PADEP's Erosion and Sediment Control General Permit for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities, or the ESCGP permit. Although the PADEP's program is intended to prevent oil and gas construction activities from polluting the waters of the Commonwealth, it has not been successful in many cases.

A February 2012 report by the PennEnvironment Research and Policy Center documented 3,355 citations for environmental violations at Pennsylvania oil and gas wells between January 1, 2008, and December 31, 2011, and 2,392 of those violations posed a direct threat to the environment.³⁴ The greatest percentage of violations (26 percent) was related to erosion and sediment control. Some operators incurred the same violations repeatedly at a single site, failing to address conditions related to the violation. Some operators repeated the same violations at multiple sites, indicating the need to improve both regulatory requirements and implementation of improved practices. Violation issues were related to both erosion and sediment control and to pollution prevention practices. There are many reasons, some of which are outlined below, why the PADEP's program has been unsuccessful in protecting water quality from surface discharges in so many cases.

First, the PADEP reviews applications for coverage under ESCGP-2 (and its predecessor, ESCGP-1) through an "expedited review process" that is too brief to allow agency staff to conduct meaningful technical reviews. For most projects, the PADEP grants permit coverage within 14 business days as long as an application is deemed administratively complete and is certified by a professional with proper credentials, such as a state-licensed engineer. For projects in special protection watersheds, on floodplains, and on contaminated brownfield sites, the PADEP's review period is 43 business days. Given the PADEP's declining budget—a 50 percent reduction over the last decade—and increasing workload during the shale gas boom, neither timeframe is long enough to allow for the meaningful technical review that an ESCGP-2 application associated with unconventional oil and gas production activities necessitates. Yet Governor Corbett's Executive Order 2012-11 directed the agency to process permit applications "as expeditiously as possible" and even made "compliance with the review deadlines a factor in any job performance evaluation." As a result, the ESCGP-2 process, whether expedited or not expedited, operates largely as a self-regulating process with limited or no PADEP technical review and oversight.

Second, the ESCGP-2 program does not include public participation opportunities. Notice is not published in the Pennsylvania Bulletin (or anywhere else) when an operator applies for coverage under ESCGP-2; notice is provided only when coverage is granted. Even if the public is aware that an application for ESCGP-2 coverage has been submitted, the PADEP's expedited review period makes it nearly impossible to meaningfully review an operator's plan before the appeal deadline (30 days from the date of Bulletin publication). The PADEP thus lacks the benefit of input from citizens who may be knowledgeable about local conditions.

Third, for as long as wells are being drilled, the well site may be considered under construction. During that period, which could last for years on a multi-well pad, the site need only be "permanently stabilized." Under that standard, erosion and sediment controls may be in place but post-construction stormwater management practices may not be required. Further, the minimal stabilization requirement applies for an additional nine months after the last well is drilled, when partial restoration begins, and under 58 Pa. C.S.

³⁴ Erica Staff, Penn Environment Research & Policy Center, *Risky Business: An Analysis of Marcellus Shale Gas Drilling Violations in Pennsylvania 2008-2011* (Feb. 2012).

§ 3216(g), operators may request restoration extensions of up to two years. The lack of stormwater management during the lengthy stabilization period means that large impervious areas will cause uncontrolled runoff.

Fourth, even after construction is complete, the PADEP's regulations do not ensure that post-construction stormwater management Best Management Practices (PCSM BMPs) will be properly designed and implemented at Oil and Gas Operations. Although those sites are required to provide stormwater management, including measures to prevent increases in stormwater runoff flow rates and volume, operators of oil and gas activities that require site restoration or reclamation are exempt from the obligation to provide an engineering *analysis* confirming that the proposed management will work as intended (§ 102.8(n)). Without the supporting engineering calculations and documentation, neither the PADEP nor the applicant have any assurance stormwater management measures will protect water quality during the long periods of well operation prior to final site restoration. We have provided recommendations for site restoration criteria in our recommendations under § 78.65.

Fifth, the PADEP's regulations do not require a PCSM plan for any projects disturbing fewer than five acres. Under § 102.5(c), ESCGPs are required only for oil and gas activities occupying at least five acres, and PCSM is required only as part of the ESCGP. This approach is flawed, because sites not meeting the five-acre threshold can pose a risk to water quality, particularly if there are numerous small sites co-located in one defined area, such as a watershed.

Sixth, in applications submitted to the PADEP under the ESCGP-2, it is common practice for both the erosion and sediment control measures and the stormwater measures to be undersized or improperly designed. Practices specific to erosion and sediment control are routinely and incorrectly applied as post-construction stormwater management practices. The guidelines provided in Chapter 4 of the Oil and Gas Operators Manual (550-0300-001) were last updated in 2001 and do reflect the current criteria provided in the March 2012 Erosion and Sediment Pollution Control Manual (No. 363-2134-008). The more stringent and technologically up to date design criteria should always apply for erosion and sediment control. The requirements of the December 2006 Pennsylvania Stormwater Best Practices Manual (363-0300-002) should prevail for stormwater management BMPs.

Seventh, under § 102.14(d)(vii), oil and gas activities that include site reclamation or restoration are exempt from the riparian buffer requirements so long as the "riparian buffer is undisturbed to the extent practicable." Because there is no guidance for application of that standard, riparian buffer waivers are routinely granted for oil and gas activities, without supporting documentation of the need to disturb the buffers and without any requirement to minimize buffer disturbance or to provide restoration.

We recommend that Chapter 78 be revised to cure as many of these defects as possible. Failure to meet the ESCGP-2 or other Chapter 102 requirements can cause harm to human health or public natural resources, especially waters of the Commonwealth. We recommend that the EQB strengthen what is now an essentially self-regulating permit process, by creating a public participation process for adjacent property owners, public resource agencies, water purveyors, and other interested parties, who can assist the PADEP in ensuring that those requirements are met. We also recommend that the EQB include guidance and requirements regarding riparian buffer protection and forested buffer restoration.

In addition, we recommend that the EQB require full compliance with Chapter 102, notwithstanding the provisions of § 102.8(n). Doing so will increase public confidence that proposed erosion and sedimentation and stormwater controls will in fact protect waters of the Commonwealth. The additional documentation is essential in the absence of any watershed-based or cumulative analysis of the impacts of Oil and Gas Operations, including chronic water pollution and flow disruption, and in the absence of a

meaningful metric for the extent impervious surface the PADEP will allow to remain after restoration occurs across numerous and dispersed well sites.

We recommend that § 78.53 be revised as follows:

§ 78.53. Erosion and sediment control, stormwater management, and riparian buffers

[During and after earthmoving or soil disturbing activities, including the activities related to siting, drilling, completing, producing, servicing and plugging the well, constructing, utilizing and restoring the access road and restoring the site, the operator shall design, implement and maintain best management practices in accordance with] (a) Any person proposing or conducting earth disturbance activities associated with oil and gas activities shall comply with Chapter 102 (relating to erosion and sediment control and stormwater management) [and an erosion and sediment control plan prepared under that chapter]. Best management practices for erosion and sediment control for oil and gas ~~well~~ operations activities are listed in the [*Oil And Gas Operators Manual, Commonwealth of Pennsylvania, Department of Environmental Protection, Guidance No. 550-0300-001 (April 1997), as amended and updated*] Erosion and Sediment Pollution Control Program Manual, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 363-2134-008, as amended and updated, and the Oil and Gas Operators Manual, Commonwealth of Pennsylvania, Department of Environmental Protection, Guidance No. 550-0300-001, as amended and updated. Best management practices for stormwater management are listed in the Pennsylvania Stormwater BMP Manual, Department of Environmental Protection, 363-0300-002. The guidelines of the most recently updated document shall prevail.

(b) NOIs, as defined in § 102.1, for Oil and Gas Operations shall be published in the Pennsylvania Bulletin, and the PADEP may not issue its determination on a permit application until a thirty-day period for public review and comment is complete.

(c) Any person may submit notice to the Department of documentation and design deficiencies related to erosion and sediment control or stormwater management in a permit application submitted by any oil and gas operation seeking permit coverage under Chapter 102. Provided that the notice includes documentation of the specific components of the permit application that do not meet Chapter 102 requirements, the Department shall deliver written acknowledgement of the notice to both the applicant and the person submitting the notice within 14 days of receiving the notice. The Department shall have an additional 14 days to complete a written deficiency determination. If the Department identifies deficiencies, the permit holder shall have 14 days to address all deficiencies. If the deficiencies are not addressed within the 14-day period, permit coverage shall be suspended until all deficiencies are addressed.

(d) Two years after site disturbance begins and until full site restoration is complete, notwithstanding the provisions of § 102.8(n), the post-construction stormwater management required under Chapter 102 shall be implemented at all areas of a well site not needed for safe Oil and Gas Operations. The areas needed for safe Oil and Gas operations include the following:

- (1) Areas used for service vehicle, well workover equipment, and rig access.**
- (2) Areas used for storage tanks and secondary containment facilities.**
- (3) Areas used for wellheads and appurtenant processing facilities.**
- (4) Areas used for any necessary safety buffer limited to the area surrounding equipment that is physically cordoned off to protect the facilities.**

(5) Areas used to store supplies or equipment required for exploration or production operations.

(6) Areas used for operation and maintenance of long-term PCSM best management practices.

(e) Notwithstanding the provisions of § 102.8(n), a person proposing oil and gas activities that involve one (1) acre or more of earth disturbance over the life of the project shall comply fully with the erosion and sediment control and stormwater management requirements of Chapter 102.

(f) Existing riparian buffers shall be considered undisturbed to the extent practicable, within the meaning of § 102.14(d)(vii), provided that there is no removal of vegetation or site disturbance within the riparian buffer. For wooded riparian buffers, disturbance or compaction of the root zone of wooded vegetation shall be considered disturbance. Direct discharge of stormwater to riparian buffer areas without prior stormwater management is prohibited. If riparian buffer disturbance occurs, forested riparian buffer restoration in accordance with the technical requirements of § 102.14 is required for all disturbed areas.

§ 78.55 Emergency Response Planning

Proposed Regulation: The EQB proposes to revise emergency response planning requirements for unconventional wells in § 78.55. Operators are required to prepare a Preparedness, Prevention, and Contingency (PPC) Plan in conformance with the 2001 Pennsylvania *Guidelines for the Development and Implementation of Environmental Emergency Response Plans*.³⁵

Comment: We support the requirement to prepare a PPC plan. However, we do not agree that the requirement to prepare a PPC plan should apply only to unconventional wells (shale gas wells). A PPC plan is needed for all Oil and Gas Operations as defined at § 78.1, which includes all wells and well sites.

Pennsylvania currently estimates that the environmental hazard associated with conventional wells (\$10 billion) far exceeds that of unconventional wells (\$713 million). The 2013 Pennsylvania Standard State All-Hazard Mitigation Plan estimates that conventional oil and gas well incident hazards could occur at 1,183 facilities, potentially impacting over a million buildings, with a replacement value of over \$10 billion, based on “brick-and-mortar structures located within 1000 yards of an active or abandoned conventional oil or gas well.”³⁶ The same report estimates that unconventional oil and gas well incident hazards could occur at 77 facilities, potentially impacting over a hundred thousand buildings, with a replacement value of over \$713 million, based on “brick-and-mortar structures located within 1000 yards of an active, inactive, or plugged unconventional oil or gas well.”³⁷ Additionally, the Pennsylvania Standard State All-Hazard Mitigation Plan states that there is a risk of private water supply contamination:

*Private water supplies such as domestic drinking water wells in the vicinity of oil and gas wells are at risk of contamination from brine and other pollutants including methane which can pose a fire hazard.*³⁸

³⁵ PADEP, *Guidelines for the Development and Implementation of Environmental Emergency Response Plans*, No. 300-2200-001 (Sept. 2001) [hereinafter *2001 Guidelines*].

³⁶ 2013 Pennsylvania Standard State All-Hazard Mitigation Plan, page 131, http://www.portal.state.pa.us/portal/server.pt/community/programs_and_services/4547/hazard_mitigation_forms_presentations_and_other_documents/806856.

³⁷ *Id.*

³⁸ *Id.* at 419.

The 2001 Pennsylvania *Guidelines for the Development and Implementation of Environmental Emergency Response Plans* state that a Spill Prevention Response (SPR) is required for regulated storage tank facilities with an aggregate aboveground storage tank capacity of more than 21,000 gallons.³⁹ Oil and Gas Operations should also require a SPR, but this is not addressed in the proposed regulation.

The proposed regulation is written in a confusing manner. First, it requires a PPC plan for Oil and Gas Operations, but provides incomplete instruction on what is required. Second, it does not advise the operator when a SPR plan is needed.

We recommend that the regulation be re-written to clarify that all Oil and Gas Operations require a PPC plan and that a SPR may be required if a storage tank with a capacity of more than 21,000 gallons is used. We recommend the emergency response elements listed in § 78.55(i) be included in one integrated PPC plan, rather than having two separate plans (a PPC Plan and a separate Emergency Response Plan for the wellsite).

The proposed regulations do not require PADEP review and approval of the PPC plan before Oil and Gas Operations commence or when the plan is amended. We recommend that the PADEP review and approve the PPC plan as part of the permit application process and that the PADEP review and approve amendments and that Pennsylvania update its All-Hazard Mitigation Plan to include information provided in the industry plans.

We also recommend that local governments be consulted by the applicant in the preparation of the PPC Plan to ensure that any responsibilities assumed or assigned to the local government in the plan can be delivered by the local government. The applicant should also be required to provide adequate funding to the local government and/or provides supplemental resources to provide a high-quality response system. Local governments should also update their local All-Hazard Mitigation Plan to include information provided in the industry plans.

We support the requirement for a pressure barrier policy to be contained in the PPC plan; however, we recommend that the regulation clarify that a minimum of two pressure barriers (the initial and a redundant backup) be required, consistent with industry's two-barrier safety recommended practice, because "hazards are contained by multiple protective barriers."^{40,41}

The distribution list contained in the 2001 PPC Guidance document at Section I, Subpart D requires a copy to be provided to the PADEP and agencies that may become involved in the response. The proposed regulation should at least match the distribution requirement in the 2001 PPC Guidance document. The proposed regulation states that copies of the PPC plan will be provided only to the PADEP, landowner, and Fish and Boat Commission upon request. We recommend that plan distribution be expanded. Local governments, first responders, and residents on or adjacent to land used for Oil and Gas Operations should receive copies of the PPC plan prior to commencement of construction activities.

The regulation should clarify that the PPC plan must include sufficient information to demonstrate the oil and gas operator has sufficient equipment and trained and qualified personnel immediately available, or

³⁹2001 *Guidelines, supra*.

⁴⁰ Int'l Ass'n of Oil & Gas Producers, *Asset Integrity – the Key to Managing Major Incident Risks*, Report No. 415 (Dec. 2008).

⁴¹ Int'l Ass'n of Oil & Gas Producers, *Process Safety – Recommended Practices on Key Performance Indicators*, Report No. 456 (Nov. 2011).

on contract, to contain, control and clean up the worst-case discharge or respond to the worst-case emergency.

The PPC plan should incorporate National Incident Management System planning standards,^{42,43} including the use of the Incident Command System, Incident Action Planning and Common Communications Plans⁴⁴ for all Oil and Gas Operations (defined at § 78.1), not just unconventional well operations.

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. Larger, paid fire and emergency services departments, located near existing industrial developments, may have some industrial firefighting capability; however, the level of capability should be assessed by the operator and supplemented. If local emergency response services are relied upon in the PPC, operators should ensure emergency response personnel are trained, qualified, and equipped to respond to oil and gas industrial accidents. Small, local, volunteer fire and emergency services departments will typically not be equipped or qualified to meet this need.

On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells.⁴⁵ Blowout rates are less frequent for production wells where more information is known about the reservoir, well control is optimized, and personnel are more experienced in site-specific conditions. For example, a review of production well blowouts in California estimated 1 blowout per 2,500 wells drilled.⁴⁶ California's data showed that: 25% of the blowouts affected more than 25 acres; the average blowout lasted 18 hours; and the maximum blowout length was 6 months. Therefore, blowouts are a reasonably foreseeable significant impact, and mitigation is warranted.

Hydrocarbon reservoirs can contain large quantities of gas and formation water, which can be released into the surrounding environment during a well blowout, resulting in significant damage. For example, the Chesapeake Energy 2011 Marcellus well blowout in Bradford County, Pennsylvania spilled thousands of gallons of fracture treatment fluid over "containment walls, through fields, personal property and farms, even where cattle continue[d] to graze."⁴⁷

Methods to control a gas well blowout can require significant water withdrawals – from 500,000 to 6,000,000 gallons per day. Well control experts may also use foam and dry chemicals to respond to a blowout. Controlling a well blowout can create large volumes of waste. Rig-deluge operations create

⁴² See the Federal Emergency Management Administration website for a complete description of the National Incident Management System planning standards, <http://www.fema.gov/national-incident-management-system>.

⁴³ See the Pennsylvania State Fire Commissioner website for a description of the National Incident Management System and how it relates to responding to oil and gas emergencies in Pennsylvania, <http://www.portal.state.pa.us/portal/server.pt/community/nims>.

⁴⁴ See the Federal Emergency Management Administration website for a complete set of Incident Command System forms and instructions, <http://www.fema.gov/forms/job-aids-tools-templates>.

⁴⁵ S. Rana, *Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies*, 4-6 (Aug. 2009) (SPE Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference).

⁴⁶ P.D. Jordan, & S.M. Benson, *Well Blowout Rates in California Oil and Gas District 4- Update and Trends, Summary of Well Blowout Risks for California Oil and Gas District 4, 1991-2005*, Table 1.

⁴⁷ *Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid*, The Huffington Post, (Apr. 20, 2011), <http://www.huffingtonpost.com/2011/04/20/pennsylvania-fracking-spill-gas-blowout-2011n851637.html>.

large pools of water that can transport oil, chemicals, fuels, and other materials toward lower elevation drainage areas.

In addition to the Chesapeake Energy 2011 well blowout, another Pennsylvania Marcellus Shale blowout occurred in 2010.^{48,49} Also, in 2010, there was a major industrial fire. The news reported that it took “16 hours for out-of-state crews to address a June 3 blowout in Clearfield County and 11 hours to extinguish a July 23 fire in Allegheny County. In both cases, well operators had to wait for response crews to fly in from Texas.”⁵⁰ In 2010, CUDD Well Control located a new facility in Canton Township, Bradford County, Pennsylvania. It is recommended that the regulation require operators to have a contract in place for immediate response by a trained and qualified well control contractor. If a contract with a well control expert is not in place when a blowout occurs, contract negotiations can cause detrimental delays.

A recent gas well fire (February 2014) at a Chevron well in Greene County Pennsylvania lasted two weeks⁵¹ and resulted in the death of one worker.⁵² The cause of the gas well explosion is under investigation by the PADEP, but early reports indicate a defective wellhead. The well was brought under control by a specialized well capping expert, Wild Well Control. The initial well explosion also resulted in a fire at an adjacent well.⁵³

Well capping is a proven, effective, and rapid method to control a blowout. Well control contractors provide the expertise and equipment for this operation. However, in some limited cases, well capping is not effective, and a relief well may be required. Therefore, it is important for operators to also have prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement to provide emergency response assistance with a nearby operator.

The regulation should also include requirements for the operator to conduct drills to practice the plan, and for the PADEP to audit the plan via drills, exercises, equipment inspections, and personnel training audits.

§ 78.55. ~~Control and disposal planning;~~ Emergency Response Plans for Oil and Gas Operations unconventional well sites.

(a) Preparation and implementation of plan for **Oil and Gas Operations**. [Prior to generation of waste, the well operator shall prepare and implement a plan under § 91.34 (relating to activities utilizing pollutants) for the control and disposal of fluids, residual waste and drill cuttings, including top-hole water, brines, drilling fluids, additives, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.] Persons conducting **Oil and Gas Operations** shall prepare and implement site specific PPC plans according to §§ 91.34 and 102.5(l) (relating to activities utilizing pollutants; and permit requirements).

⁴⁸ *Blowout Occurs at Pennsylvania Gas Well*, Wall Street Journal (June 4, 2010).

⁴⁹ *Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid*, The Huffington Post, (Apr. 20, 2011), <http://www.huffingtonpost.com/2011/04/20/pennsylvania-fracking-spill-gas-blowout-2011n851637.html>.

⁵⁰ *Emergency Crews Set for Pa. Wells* (Aug. 25, 2010), <http://pagasdrilling.com/tag/cudd-well-control/>.

⁵¹ K. Colaneri, *Crews Cap Leaking Chevron Gas Well That Started Fire in Southwest Pa*, StateImpact (Feb. 24, 2014), <http://stateimpact.npr.org/pennsylvania/2014/02/24/crews-cap-leaking-chevron-gas-well-that-started-fire-in-southwest-pa/>.

⁵² J. Casto, *State Police Recover remains of worker from Greene County Gas Well Fire*, TribLiveNews (Feb. 19, 2014), <http://triblive.com/news/adminpage/5624873-74/gas-state-pad#axzz2vW0Y8fEK>.

⁵³ K. Colaneri, *Well Fire in Southwest Pa. May Burn Through the Weekend*, StateImpact (Feb. 14, 2014), <http://stateimpact.npr.org/pennsylvania/2014/02/14/well-fire-in-southwest-pa-may-burn-through-the-weekend/>.

(1) The PPC plan shall include information demonstrating that the oil and gas operator has sufficient equipment and trained and qualified personnel immediately available, or on contract, to contain, control and clean up the worst-case discharge or respond to the worst-case emergency.

(2) If local emergency response resources are relied on in the PPC, operators shall ensure they are trained, qualified, and equipped to respond to an industrial accident. Operators are required to provide adequate funding to the local government and provide sufficient industrial response equipment and trained and qualified personnel to supplement local emergency response resources to ensure that there are sufficient resources, in total, to contain, control and clean up the worst-case discharge or respond to the worst-case emergency.

(3) The operator must conduct an annual drill to test the PPC, with sufficient prior notice to the Department and local emergency response resources that are relied on under the PPC to ensure that they have an opportunity to participate.

(4) In addition to the PPC Plan, a Spill Prevention Response (SPR) is also required for regulated storage tank facilities with an aggregate aboveground storage tank capacity of more than 21,000 gallons.

(b) Preparation and implementation of a plan for well sites. In addition to the requirements in subsection (a), the well operator shall prepare and develop a site specific PPC plan prior to storing, using, generating or transporting regulated substances to, on or from a well site from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.

(1) The PPC plan shall include a written well blowout response plan, a contract retainer with an emergency well control expert, and prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement, to provide emergency response assistance with a nearby operator.

(2) If local emergency response resources are relied on in the PPC, operators shall ensure they are trained, qualified, and equipped to respond to an industrial accident. If the operator cannot demonstrate that local emergency responders have the required training, qualifications, an equipment to respond to an industrial accident, the operator should be required to provide its own response resources or have a contract in place with a qualified professional.

(c) Containment practices. The ~~unconventional~~ well operator's PPC plan must describe the containment practices to be utilized at the Oil and Gas Operation and the area of the well site where containment systems will be employed as required under § 78.64a (relating to containment systems and practices at unconventional well sites). The PPC plan must include a description of the equipment to be kept onsite during drilling and hydraulic fracturing operations, and all other Oil and Gas Operations, that can be utilized to prevent a spill from leaving the well site.

[(b)] (d) Requirements. The well operator's PPC plan must also identify the control and disposal methods and practices utilized by the ~~well~~ operator and be consistent with the act, The Clean Streams Law (35 P. S. §§ 691.1—691.1001), the Solid Waste Management Act (35 P. S. §§ 6018.101—6018.1003) and §§ 78.54, 78.56—78.58 and 78.60—78.63. The PPC plan must also include a pressure barrier policy **developed by the operator that identifies a minimum of two pressure barriers to be used during all identified Oil and Gas Operations.**

[(c)] (e) Approval and Revisions. The well operator shall submit the PPC and SPR plans to the Department for review and approval as part of the permit application. Operations may not commence until Department approval of the PPC and SPR plans is complete. Proposed revisions to revise the PPC and SPR plans must be submitted to the Department for review and approval prior to implementing a change to the practices identified in the PPC and SPR plans.

Once approved, the Department will **audit each PPC and SPR plan at least once every five years at an oil and/or gas production operation, or once during the well construction operation to verify that there is sufficient trained and qualified personnel and equipment available to carry out the plan.**

[(d)] (f) Copies. A copy of the well operator's PPC **and SPR** plans shall be provided to the Department, **the Fish and Boat Commission, or the land owner, residents on or adjacent to the land to be used, the County and Local Emergency Management Agency, Local Fire and Medical Service Agencies that would be involved in the response upon request** and shall be available at the [well] site during drilling and completion activities for review.

(g) Guidelines. With the exception of the pressure barrier policy required under subsection (d), **a PPC and SPR plans** developed in conformance with the Guidelines for the Development and Implementation of Environmental Emergency Response Plans, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 400-2200-001, as amended and updated, will be deemed to meet the requirements of this section.

[(e)] (h) Emergency contacts. A list of emergency contact phone numbers for the area in which the well site is located must be included in the PPC **and SPR** plans and be prominently displayed at the well site during drilling, completion, or alteration activities.

[(f)] (i) Emergency response **planning elements required in the PPC and SRP Plans Oil and Gas Operations.**

- (1) Applicability. This subsection applies to **all Oil and Gas Operations unconventional wells.**
- (2) Definitions. For the purposes of this subsection, the following definitions apply:

* * * * *

Emergency responder—Police, firefighters, emergency medical technicians, paramedics, emergency management personnel, **oil and gas personnel trained and qualified for response to emergencies and their contract staff, well control experts,** public health personnel, state certified hazardous materials response teams, Department emergency personnel and other personnel authorized in the course of their occupations or duties, or as an authorized volunteer, to respond to an emergency.

* * * * *

- (3) Registration of addresses.

(i) Prior to construction of an access road to a well site, the operator of an **unconventional oil or gas** well shall request a street address for the well site from the county or municipality responsible for assigning street addresses.

* * * * *

- (4) Signage.

(i) Prior to construction of the access road, the operator of an **unconventional oil or gas** well shall display a reflective sign at the entrance.

* * * * *

- (5) Emergency response.

(i) The operator of an **Oil and Gas Operation unconventional well** shall develop and implement an emergency response plan that provides for equipment, procedures, training and documentation to properly respond to emergencies that threaten human health and safety **for each well site.** The plan shall

incorporate National Incident Management System planning standards, including the use of the Incident Command System, Incident Action Planning and Common Communications Plans. The plan must include:

(A) The emergency contact information, including phone numbers, for the well operator's local representative for the **Oil and Gas Operation well-site** and the **well** operator's 24-hour emergency phone number.

(B) The emergency notification procedures that the operator shall utilize to contact emergency responders during an emergency.

(C) A description of the **Oil and Gas Operation well-site** personnel's response to the following **well-site** emergencies:

(I) Fire.

(II) Medical emergency.

(III) Explosion or similar event.

(IV) Spill.

(V) Security breach or other security event.

(VI) Any other incident that necessitates the presence of emergency responders.

(D) A description of the procedure to be used to provide the most current information to emergency responders in the event of an emergency, including the following:

(I) The current Material Safety Data Sheet (MSDS) required under law to be present at the **Oil and Gas Operation well-site**.

(II) The location of the MSDSs at the **Oil and Gas Operation well-site**.

(III) The name of the position in the operator's organization responsible for providing the information in subclauses (I) and (II).

(E) A list containing the location of any fire suppression, **well control** and spill control equipment maintained by the **Oil and Gas Operator** at the **Oil and Gas Operation well-site**.

(F) A description of any emergency equipment available to the operator that is located off of the **Oil and Gas Operation well-site**.

(G) A summary of the risks and hazards to the public within **1 ½** mile of the well site and the associated planning assumptions.

(H) An outline of the emergency response training **and qualification** plan that the operator has established.

(ii) The emergency response plan in subparagraph (i) may consist of two parts:

(A) A base plan common to all of the operator's **Oil and Gas Operations well-site** containing some of the elements described in subparagraph (i).

(B) A site-specific plan containing the remaining elements described in subparagraph (i).

(iii) The operator shall submit a copy of the current emergency response plan for that well site unless the permit provides otherwise. For plans using the approach in subparagraph (ii), the operator may submit one base plan provided that the site-specific plans are submitted for each well site.

(iv) The operator shall review the plan and submit an update annually on or before March 1 each year **for Department review and approval in accordance with § 78.55(e)**. In the event that updates are not

made to the plan for that review period, the operator shall submit a statement indicating the review was completed and updates to the plan were not necessary.

(v) The plan and subsequent updates shall be submitted to:

- (A) PEMA.
- (B) The Department.
- (C) The county emergency management agency.
- (D) The Public Safety Answering Point with jurisdiction over the well site.

(E) The landowner and residents on or adjacent to the land where the Oil and Gas Operation is located.

(F) The local government.

(vi) A copy of the plan shall be available at the **Oil and Gas Operation well site** during all phases of operation.

(vii) The emergency response plan must address response actions for **Oil and Gas Operations as defined in § 78.1, the following stages of operations at the well site:**

- ~~—(A) Preparation of the access road and well site.~~
- ~~—(B) Drilling of the well.~~
- ~~—(C) Hydraulic fracturing and stimulation of the well.~~
- ~~—(D) Production.~~
- ~~—(E) Well site restoration.~~
- ~~—(F) Plugging of the well.~~

(viii) The requirements in subparagraphs (i)—(vii) may be met by implementing guidance issued by the Department in coordination with PEMA.

~~—(6) Transition.~~

~~—(i) This subsection is effective January 26, 2013, except as provided in subparagraph (ii).~~

~~—(ii) For a well site containing a well that is being drilled or has been drilled as of January 26, 2013, or a well site for which a well permit has been issued but wells have not started drilling as of January 26, 2013, or a well site for which an administratively complete application is pending as of January 26, 2013, as provided in subparagraph (i), the following applies:~~

- ~~—(A) Paragraph (3) is effective on February 25, 2013.~~
- ~~—(B) Paragraph (4) is effective on July 25, 2013.~~
- ~~—(C) Paragraph (5) is effective on April 26, 2013.~~

§ 78.56 Temporary Storage

Proposed Regulation: The EQB proposes changes to § 78.56 to allow certain types of temporary tanks to be used at the well site. The EQB also proposes new monitoring, fencing, sign, and pit construction requirements for unconventional wells (shale gas wells). These new requirements would not apply to all oil and gas well sites.

Comment: We do not support limiting new requirements to unconventional wells only. Best practices for temporary storage should apply to all wells.

We oppose the use of open pits for temporary waste storage, because of the pollution hazards posed.

We oppose continued allowance and waivers for the long-term burial of drilling waste on-site. It is inefficient to construct a temporary pit that could leak and then transfer that waste later to a tank to remove the waste to an approved waste handling site. It is more efficient to place the waste directly into the tank that will be used to transport it to an approved waste handling site. Such closed loop systems are more conducive to recycling than open pit storage.

Open pits have the potential to contaminate groundwater and surface water and many spills, leaks, and other problems involving pits have occurred statewide. The state's continued use of production pits poses significant environmental problems.⁵⁴ Open pits and open tanks contribute to air pollution. Oil and Gas Operations, like the ones shown in the photo above can be located very close to homes and nearby residents should be protected from inhaling toxic vapors from these operations. Closed-loop tank systems should be used to contain volatile materials and wastes to capture air pollution and route vapors to be sold or used for power (preferably), or alternatively to an incinerator or flare.

The photo on the previous page shows homes within close proximity to shale drilling operations in Hopewell Township, Washington County, PA.

We recommend deletion of all regulations that allow pits.⁵⁵ Waste and regulated substances should be stored in covered aboveground storage tanks or modular structures.

We support the use of closed-loop temporary tankage for handling materials, chemicals, and waste at Oil and Gas Operations, providing that they do not pose pollution or other environmental and health hazards, generate new problems such as excessive truck traffic, or land disturbance from pipelines. While closed containment systems such as



tanks can be preferable to impoundments for air and water quality, they are not risk-free and require strong regulation and oversight. Any facility that holds flowback water, brine, and other gas wastes, and from which substances are transported, can pose threats to the environment and health. For tanks to be beneficial, their location and size must be appropriate for the site in question. Tanks must be enclosed to

⁵⁴ The State Review of Oil and Gas Environmental Regulations “Pennsylvania Hydraulic Fracturing Review” (STRONGER, 2010) Finding III.4 stated: “the DEP’s experience with pits has shown that, although their use is decreasing, many liner failures still occur with pits and other types of waste are being dumped into pits.” STRONGER recommended that DEP “consider adopting regulations or incentives for alternatives to pits used for unconventional wells in order to prevent the threat of pollution to the waters of the Commonwealth.”

⁵⁵ In the event that the EQB rejects our recommendation that pits be prohibited, we have annexed alternative suggestions in Appendix A to improve the regulation of pits proposed in this section.

prevent air pollution, have sufficient containment to prevent leaks and subsequent water and soil contamination, and be consistently and properly inspected and maintained. For tanks that are vented, filtering or capture and control of pollutants is essential to protect people from harmful air emissions depending on the tank content type.

We support the proposed change that includes PADEP development of an approved list of modular temporary storage units that are allowed. However, we request that the PADEP include a definition for modular storage structure in the definition section at § 78.1. We assume that the EQB is referring to modular storage structures such as connexs and other metal-sided box shaped structures that are pre-fabricated and brought to the oil and gas site to safely store materials on site, out of the weather and so that they can be secured by a lock, although this needs clarification. If the EQB is considering modular storage structures to contain other hazardous materials such as fuels and chemicals, it needs to be clear what structures it envisions and how they are appropriate and safe for that use.

We request that the PADEP make it clear what can be stored in a temporary tank, and what can be stored in an approved modular storage structure.

It is also essential that the PADEP clarify whether these tanks and “tank farms” would be for principal use at well sites or also be allowed to service multiple wells from a wide radius (as is the case with existing centralized impoundments).

The PADEP should also clarify when operators would be required to obtain a Waste Management Permit (WMGR 123) for tanks and “tank farms;” this aspect was indicated as an area for regulatory review during the April 23, 2013 Technical Advisory Board (TAB) meeting.

We support the requirement for lined containment areas to be placed under temporary storage. A temporary tank poses a greater environmental risk than a stationary tank, because temporary tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit and the likelihood of tank appurtenance leakage.

Liners should be impervious and impermeable (not allowing fluid to pass through). The proposed regulation would allow some permeability through the liner, albeit a small coefficient of permeability is proposed. No amount of leakage should be allowed. Lined containment should be “leak proof.”

The proposed language contains conflicting instructions about disposal of drill cuttings. Existing regulation § 78.56 requires that the operator shall contain polluttional substances including drill cuttings. The revised language includes a proposed option for land application of drill cuttings. We do not support land application of drill cuttings. Please see our recommendations below in our comments on the proposed regulation at § 78.61.

The regulation should clarify that the PADEP approves the use of fully enclosed aboveground storage tanks and modular structures, that uncovered storage containers may not be used for any wastes, and that temporary use of buried tanks and structures are prohibited. Pits currently in use should be phased out within one year.

We recommend that the PADEP require storage tank inspections and alarm systems. Tank inspections should be conducted at least once every five years to examine structural conditions and document corrosion or damage, and identify necessary repairs before returning the tank to service. Monitoring and control systems should be installed, including high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed

to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

We recommend the following changes to the proposed regulations at § 78.56:

§ 78.56. [Pits and tanks for temporary containment] Temporary Approved Aboveground Storage Tanks and Modular Structures; Prohibition of Pits.

(a) Except as provided in §§ 78.60(b) ~~and 78.61(b)~~ (relating to discharge requirements; ~~and disposal of drill cuttings~~), the operator shall contain **[pollutional] regulated** substances and wastes from the drilling, altering, completing, recompleting, servicing and plugging the well, including brines, drill cuttings, drilling muds, oils, stimulation fluids, well treatment and servicing fluids, plugging and drilling fluids other than gases in a pit, aboveground tank or series of ~~pits and~~ tanks ~~or other approved storage modular structures approved by the Department. The use of buried tanks and buried modular structures are prohibited.~~ The operator shall install or construct and maintain the pit, aboveground tank or series of ~~pits and~~ tanks ~~or other approved storage modular~~ structures in accordance with the following requirements:

(1) The ~~pit,~~ tank [or], series ~~of pits and~~ tanks, ~~or other approved storage modular structures~~ shall be constructed and maintained with sufficient capacity to contain all **[pollutional] regulated** substances and wastes which are used or produced during drilling, altering, completing, ~~recompleting, servicing and~~ plugging the well. Tanks or other authorized storage equipment may not be located in a mapped floodplain or within 50 feet of the top of bank of any watercourse.

(2) Modular aboveground storage structures that are assembled onsite may not be utilized to store regulated substances; only factory prefabricated modular storage structures are allowed, without Department approval. The Department will maintain a list of approved aboveground tanks and modular storage structures on its web site and will make clear the type of regulated substances that can be safely stored in each approved tank or the structure. The owner or operator shall notify the Department at least 3 business days before the ~~beginning of construction~~ planned use of these storage structures. The notice shall be submitted electronically to the Department through its web site and include the date the aboveground tank or modular storage structure installation will begin. If the date of installation is extended, the operator shall renotify the Department with the date that the installation will begin, which does not need to be 3 business days in advance.

~~[(2)] (3)~~ Aboveground tanks and modular storage structures containing volatile materials and wastes shall be designed and operated to capture air pollution and route vapors to power generation equipment (preferably), or alternatively to an incinerator or flare.

~~A pit shall be designed, constructed and maintained so that at least 2 feet of freeboard remain at all times. If open tanks or open storage structures are used, the tanks and storage structures shall be maintained so that at least 2 feet of freeboard remain at all times unless the tank or storage structure is provided with an overflow system to a standby tank or pit with sufficient volume to contain all excess fluid or [waste] regulated substances. If an open standby tank or open storage structure is used, it shall be maintained with 2 feet of freeboard. If this subsection is violated, the operator immediately shall take the necessary measures to ensure the structural stability of the pit, or tank or other storage structure, prevent spills and restore the 2 feet of freeboard.~~

~~[(3)] (4)~~ Pits [and], Aboveground storage tanks and other approved ~~storage~~ modular structures shall be designed, constructed at the factory and maintained, routinely inspected and verified to be structurally sound and reasonably protected from unauthorized acts of third parties prior to use. Each tank shall be inspected by a certified tank inspector and each modular structure shall be inspected by a structural engineer at least once every five years. The inspection shall examine structural

conditions and document corrosion or damage, and identify necessary repairs before returning it to service.

Overflow alarms shall be installed. Alarm systems shall be installed on all liquid storage tanks or other approved storage structures. The systems shall include high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

(5) ~~For unconventional well sites,~~ Unless an individual is continuously present at the well site, a fence must completely surround the storage equipment ~~all pits~~ to prevent unauthorized acts of third parties and damage caused by wildlife. Netting or fencing must be provided to prevent wildlife capture such as birds.

(6) An individual must be continuously present at the well site during well construction, well workovers and well stimulation operations. For other Oil and Gas Operations, when ~~Unless~~ an individual is not continuously present at the well site, operators shall equip all tank valves and access lids to regulated substances with reasonable measures to prevent unauthorized access by third parties such as locks, open end plugs, removable handles, retractable ladders or other measures that prevent access by third parties. Tanks storing freshwater, fire prevention materials and spill response kits are excluded from the requirements of this paragraph.

(7) The operator of ~~an unconventional~~ the well site shall display a sign on or near the tank or other approved storage structure identifying the contents and an appropriate warning of the contents such as flammable, corrosive or a similar warning.

[(4)] (8) A ~~pit~~ ~~or~~, tank or other approved modular storage structure that contains drill cuttings from below the surface casing seat, ~~[pollutional]~~ regulated substances, wastes or fluids other than tophole water, fresh water and uncontaminated-drill cuttings from above the surface casing seat shall be impermeable ~~[and comply with the following:]~~

[(i) The pits] (9) Aboveground storage tanks and other approved-modular structures ~~Pits~~ shall be set on top of constructed with a synthetic flexible liner that is sufficient in size to capture any leaks or drips that may occur from the tank or modular structure.

~~[with] that covers the bottom and sides of the pit. Liners used in a pit or other approved storage structures must~~ be impervious, impermeable and comply with the following:

~~—(i) The liner must have a coefficient of permeability of no greater than 1×10^{-7} to 10^{-10} cm/sec [and with sufficient strength and thickness to maintain the integrity of the liner].~~

~~(ii) The liner must be at least 30 mils thick. unless otherwise approved by the Department. Approval may be granted if the manufacturer demonstrates that the alternative thickness is at least as protective as a 30 mil liner. A list of approved alternative liners will be maintained on the Department's web site.~~

~~(iii) The liner shall be designed, constructed and maintained so that the physical and chemical characteristics of the liner are not adversely affected by the [waste] regulated substance stored therein and the liner is resistant to physical, chemical and other failure during transportation, handling, installation and use. Liner compatibility must satisfy ASTM Method D5747, Compatibility Test for Wastes and Membrane Liners, or another compatibility test approved by the Department for the duration~~ the pit or other the temporary storage structure is used.

~~(iv) Adjoining sections of liners shall be sealed together to prevent leakage in accordance with the manufacturer's directions. [If the operator seeks to use a liner material other than a synthetic flexible liner, the operator shall submit a plan identifying the type and thickness of the material and the~~

installation procedures to be used, and shall obtain approval of the plan by the Department before proceeding.] The integrity of all seams of the adjoining sections of liner shall be tested prior to use. Results of the tests shall be available upon request.

~~—[(ii)] (10) The pit shall be constructed so that the liner subbase is smooth, uniform and free from debris, rock and other material that may puncture, tear, cut or otherwise cause the liner to fail. The pit must be structurally sound and the interior slopes of the pit must have a slope no steeper than 2 horizontal to 1 vertical. The liner subbase and subgrade shall be capable of bearing the weight of the material above the liner without settling that may affect the integrity of the liner. If the pit bottom or sides consist of rock, shale or other materials that may cause the liner to fail, a subbase of at least 6 inches of soil, sand or smooth gravel, or sufficient amount of an equivalent material, shall be installed over the area as the subbase for the liner.~~

~~—[(iii)] (11) The bottom of the pit shall be at least 20 inches above the seasonal high groundwater table, unless the operator obtains approval under subsection (b) for a pit that exists only during dry times of the year and is located above groundwater. The operator of an unconventional well shall determine that the pit bottom is at least 20 inches above the seasonal high groundwater table prior to using the pit. A soil scientist or other similarly trained person using accepted and documented scientific methods shall make the determination. The individual's determination must contain a statement certifying that the pit bottom is at least 20 inches above the seasonal high groundwater table according to observed field conditions. The name, qualifications and statement of the individual making the determination and the basis of the determination shall be provided to the Department upon request.~~

~~—(12) Stormwater must be diverted away from the pit.~~

(13) Prior to placing storage tanks or modular structures on the liner material in the pit, the liner shall be inspected for lack of uniformity, damage and other imperfections that may cause the liner to leak. The well operator shall correct damages or imperfections before placing any the material in storage tanks or modular structures on the liner, in the pit and maintain the pit until closure of the pit.

[(iv)] (14) If a liner becomes torn or otherwise loses its integrity, storage tanks or modular structures must be continuously monitored for leaks by onsite personnel while the liner is repaired. the pit or approved storage structure shall be managed to prevent the [pit] contents from leaking [from the pit]. If repair of the liner or construction of another temporary pit or approved storage structure is not practical or possible, the storage tank or modular structure [pit] contents shall be removed and disposed of at an approved waste disposal facility or disposed on the well site in accordance with § 78.61, § 78.62 or § 78.63 (relating to disposal of residual waste—pits; and disposal of residual waste—land application).

~~—[(v)] (15) The liner shall be secured around the perimeter of the pit in a manner that does not compromise the integrity of the liner. If the liner drops below the 2 feet of freeboard, the pit shall be managed to prevent the pit contents from leaking from the pit and the 2 feet of lined freeboard shall be restored.~~

(16) The **unconventional** well operator shall notify the Department at least 3 business days before the installation of the **pit** liner. The notice shall be submitted electronically to the Department through its web site and include the date the liner will be installed. If the date of installation is extended, the operator shall renotify the Department with the date of installation, which does not need to be 3 business days in advance. ~~Notice is not required if the A licensed professional engineer or geologist shall that designed the well site and shall submits a statement on forms provided by the Department certifying that the **pit and the pit** liner, as built, are compliant~~

with this section. This certification shall be submitted within 10 business days of installation of the pit liner.

(17) Condensate, oil, natural gas, or volatile substances, whether separated or mixed with other fluids, may not be stored in any open top structure or pit. Tanks and modular structures used for storing or separating condensate, oil, natural gas, or volatile substances during well completion shall be grounded, monitored and have controls to capture vapors. All captured vapors shall be used for power or, upon demonstration of good cause, shall be routed to an incinerator or flare, and to prevent vapors from exceeding the lower explosive limits of the condensate outside the tank or modular structure, and Tanks used for storing or separating condensate shall be grounded.

(b) The operator may request to use practices other than those specified in subsection (a) which provide equivalent or superior protection by submitting a request to the Department for approval. Use of pits or uncovered storage containers will not be approved as meeting the standard of equivalent or superior protection. The request shall be made on forms provided by the Department.

(c) Storage and disposal of uncontaminated all drill cuttings, regardless if from above or below the surface casing seat, in pits is prohibited. in a pit or by land application shall comply with § 78.61. A pit used for the disposal of residual waste, including contaminated drill cuttings, shall comply with § 78.62. Disposal of residual waste, including contaminated drill cuttings, by land application shall comply with § 78.63.

(d) Storage and disposal of contaminated fluids, semifluids, or solids associated with oil and gas activities, including, but not limited to, fresh water, wastewater, flowback, mine influenced water, and drilling mud, in pits is prohibited. All existing pits used to store and dispose of contaminated fluids, semifluids, or solids associated with oil and gas activities, including, but not limited to, wastewater, flowback, mine influenced water, and drilling mud must be removed and the pit be remediated by Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking).

~~—(d) [Unless a permit under The Clean Streams Law (35 P. S. §§ 691.1—691.1001) or approval under § 78.57 or § 78.58 (relating to control, storage and disposal of production fluids; and existing pits used for the control, storage and disposal of production fluids) has been obtained for the pit, the] The owner or operator shall remove or fill the pit within 9 months after completion of drilling, or in accordance with the extension granted by the Department under section [206(g) of the act (58 P. S. § 601.206(g))] 3216(g) of the act (relating to well site restoration) and § 78.65(d) (relating to site restoration). Pits used during servicing, plugging and recompleting the well shall be removed or filled within 90 calendar days of construction.~~

§ 78.57 Control, Storage, and Disposal of Production Fluids

Proposed Regulation: The EQB proposes changes to § 78.57 to prohibit the use of open top structures and pits to store other production fluids generated during the production operations of a well and require tanks to be equipped with secondary containment. This proposed regulation also proposes a process for identifying and removing or obtaining approval to use underground or partially buried storage tanks.

Comment: We support the proposal to prohibit the use of open top structures and pits and the requirement to use tanks equipped with secondary containment.

We support the improvements in tank selection and secondary containment structure requirements; however, we do not agree that these improvements should apply only to new, refurbished, or replaced tanks or other aboveground containment structures. We recommend that best technology standards also

apply to existing tanks, and that operators be given a period of time to bring the tanks and other aboveground containment structures into compliance.

We support the proposal to require removal of underground or partially buried storage tanks. However, we do not support the waiver clause “unless approved by the Department.” We request that clause be deleted.⁵⁶

We recommend that buried tanks be prohibited, since they pose a risk of unchecked pollution and aboveground tanks are easier to inspect, maintain, repair, and monitor.

We also recommend incorporating many of the same recommendations we made for temporary storage tanks at § 78.56, for production tanks at § 78.57.

More specifically, we recommend the following changes to the proposed regulations at § 78.57:

§ 78.57. Control, storage and disposal of production fluids.

(a) Unless a permit has been obtained under § 78.60(a) (relating to discharge requirements), the operator shall collect the brine and other fluids produced during operation [**service and plugging**] of the well in a tank [**pit**] or a series of [**pits or**] tanks, or other device approved by the Department for subsequent disposal or reuse. **Open top structures may not be used to store brine and other fluids produced during operation of the well. Buried tanks are prohibited. All existing open top structures at existing Oil and Gas Operations must be removed by (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking.). All tanks at existing Oil and Gas Operations must meet the new standards of § 78.57 by (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking.).**

Except as allowed in this subchapter ~~or otherwise approved by the Department~~, the operator may not discharge the brine and other fluids on or into the ground or into the waters of this Commonwealth.

(b) ~~Except as provided in § 78.56 (relating to [pits and tanks for] temporary [containment] storage),~~ **The operator may not use a pit for the control, handling or storage of brine and other fluids produced during operation, service or plugging of a well [unless the pit is authorized by a permit under The Clean Streams Law (35 P. S. §§ 691.1—691.1001) or approval to operate the pit as an impoundment under The Clean Streams Law is obtained from the Department under subsection (c)].**

[(c) The operator may apply for approval from the Department to operate a pit as an impoundment under The Clean Streams Law, as indicated by the Department's issuance of a pit approval number in accordance with this section. No pit will be eligible for approval under this subsection unless the capacity of any one pit or of any two or more interconnected pits is less than 250,000 gallons, or the total capacity contained in pits on one tract or related tracts of land is less than 500,000 gallons. Compliance with this subsection does not relieve the operator from the obligation to comply with section 308 of The Clean Streams Law (35 P. S. § 691.308) and the requirements for obtaining a permit for the erection, construction and operation of treatment works promulgated under that section.]

⁵⁶ If the EQB rejects this recommendation, we ask that the EQB respond to the request set forth in Appendix A with respect to the waiver in this section.

(1) A request for approval under this subsection shall be made on forms furnished by the Department and, at a minimum, shall include the following:

(i) A description of the operator's plan that demonstrates compliance with this subsection for the construction or reconstruction of the pit.

(ii) A description of the operator's program for operation and maintenance of the pit.

(iii) A description of the method for subsequent disposal or reuse of the brine or other fluids produced during operation of the well.

(iv) A description of the operator's program for the closure of the pit and restoration of the site.

(2) The operator shall design, construct, operate and maintain the pit in accordance with the approval and the following:

(i) The pit approval number is posted at the pit in a legible and visible manner.

(ii) The pit is not located within 100 feet of a stream, wetland or body of water unless a waiver is granted by the Department.

(iii) The bottom of the pit is a minimum of 20 inches above the seasonal high groundwater table.

(iv) At least 2 feet of freeboard remain at all times.

(v) The pit is structurally sound and the inside slopes of the pit are not steeper than a ratio of 2 horizontal to 1 vertical.

(vi) The pit is impermeable and is lined with a synthetic flexible liner or alternate material that has a coefficient of permeability of no greater than 1×10^{-7} cm/sec. The liner shall be of sufficient strength and thickness to maintain the integrity of the liner. The thickness of a synthetic liner shall be at least 30 mils. Adjoining sections of liners shall be sealed together in accordance with the manufacturer's directions to prevent leakage.

(vii) The physical and chemical characteristics of the liner shall be compatible with the waste and the liner is resistant to physical, chemical and other failure during transportation, handling, installation and use. Liner compatibility shall satisfy EPA Method 9090, Compatibility Test for Wastes and Membrane Liners, or other documented data approved by the Department.

(viii) The pit shall be constructed so that the liner subbase is smooth, uniform and free of debris, rock and other material that may puncture, tear, cut, rip or otherwise cause the liner to fail. The liner subbase and subgrade shall be capable of bearing the weight of the material above the liner without settling in an amount that will affect the integrity of the liner. If the pit bottom or sides consist of rock, shale or other material that may cause the liner to leak, a subbase of at least 6 inches of soil, sand or smooth gravel, or a sufficient amount of an equivalent material shall be installed over the area as the subbase for the liner.

(ix) Prior to placing brine or other fluids in the pit, the operator shall inspect the liner and correct all damage or imperfections that may cause the liner to leak.

(x) Surface water which may drain into the pit shall be diverted away from the pit.

(xi) The pit is reasonably protected from unauthorized acts of third parties.

(3) Upon abandonment of the well or revocation of the approval by the Department, the operator shall restore the pit in accordance with the following:

(i) The free liquid fraction of the pit contents shall be removed and disposed under § 78.60(a) and the remaining pit contents and liner shall be removed and disposed under §§ 78.62 and 78.63

(relating to disposal of residual waste—pits; and disposal of residual waste—land application), or the Solid Waste Management Act.

(ii) The pit shall be backfilled to the ground surface and graded to promote runoff with no depression that would accumulate or pond water on the surface. The stability of the backfilled pit shall be compatible with the adjacent land.

(iii) The surface of the backfilled pit area shall be revegetated to stabilize the soil surface and comply with § 78.53 (relating to erosion and sedimentation control). The revegetation shall establish a diverse, effective, permanent, vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface by the landowner, the surface shall be stabilized against accelerated erosion.]

~~(e) Secondary containment capable of preventing tank contents from entering waters of the Commonwealth is required for all new, refurbished or replaced tanks or other aboveground containment structures approved by the Department, including their associated manifolds, that contain brine and other fluids produced during operation of the well. If one tank in a series of tanks is added, refurbished or replaced, secondary containment is required for the entire series of tanks. The secondary containment area provided by dikes or other methods of secondary containment open to the atmosphere must have containment capacity sufficient to hold the volume of the largest single tank, plus an additional 10% of volume for precipitation. Compliance with § 78.64 (relating to containment around oil and condensate tanks) or using double walled tanks capable of detecting a leak in the primary container fulfill the requirements in this subsection.~~

(c) The operator shall install or construct and maintain the aboveground tank and approved aboveground containment structures in accordance with the following requirements:

(1) All tanks and approved aboveground containment structures shall be constructed and maintained with sufficient capacity to contain all regulated substances and wastes that are used at the Oil and Gas Operation. All tanks shall be located on the well pad so that any spills will be captured by the containment structures and other spill prevention systems.

(2) The operator shall notify the Department at least 3 business days before the planned installation of each tank or approved aboveground containment structure. The notice shall be submitted electronically to the Department through its web site and include the date the installation will begin. If the date of installation is extended, the operator shall renotify the Department of the date that the installation will begin.

(3) All tanks and approved aboveground containment structures containing volatile materials and wastes shall be designed and operated to capture air pollution. All captured vapors shall be used for power, or upon a showing of good cause shall be routed to an incinerator or flare.

(4) All tanks and approved aboveground containment structures shall be designed and constructed at the factory and maintained, routinely inspected and verified to be structurally sound and reasonably protected from unauthorized acts of third parties prior to use. Each tank shall be inspected by a certified tank inspector at least once every five years. Each approved aboveground modular containment structure shall be inspected by a structural engineer at least once every five years. The inspection shall examine structural conditions, document corrosion or damage, and identify necessary repairs before returning it to service.

(5) Overflow alarm systems shall be installed on all liquid storage tanks. The systems shall include high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

(6) Unless an individual is continuously present at the Oil and Gas Operation, a fence must completely surround the storage equipment to prevent unauthorized acts of third parties and damage caused by wildlife.

(7) Unless an individual is continuously present at the Oil and Gas Operation, operators shall equip all valves and access lids to regulated substances with reasonable measures to prevent unauthorized access by third parties such as locks, open end plugs, removable handles, retractable ladders or other measures that prevent access by third parties. Each tank and approved aboveground containment structure storing freshwater, fire prevention materials and spill response kits is excluded from the requirements of this paragraph.

(8) The operator shall display a sign on or near the each tank and approved aboveground containment structure identifying the contents and providing an appropriate warning of the contents, such as flammable, corrosive or another description of the relevant danger.

(9) Secondary containment liners capable of preventing tank and approved aboveground containment structures contents from entering waters of the Commonwealth is required for all existing, new, refurbished or replaced tanks or other aboveground containment structures approved by the Department, including their associated manifolds, that contain brine and other fluids produced during operation of the well. New, refurbished or replaced tank and approved aboveground containment structures must meet this standard upon construction or installation. Existing tanks must meet these standards by _____ (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking.).

If one tank in a series of tanks is added, refurbished or replaced, secondary containment is required for the entire series of tanks. The secondary containment area provided by dikes or other methods of secondary containment open to the atmosphere must have containment capacity sufficient to hold the volume of the largest single tank, plus an additional 10% of volume for precipitation. Compliance with § 78.64 (relating to containment around oil and condensate tanks) or using double walled tanks capable of detecting a leak in the primary container fulfill the requirements in this subsection.

All tanks and approved aboveground containment structures shall be set on top of a synthetic flexible liner that is sufficient in size to capture any leaks or drips that may occur from the tank or modular structure. Liners shall be impervious, impermeable, at least 30 mils thick; no "alternate methods" allowing for thinner liners shall be allowed. The liner shall be designed, constructed, and maintained so that the physical and chemical characteristics of the liner are not adversely affected by the regulated substance stored therein and the liner is resistant to physical, chemical and other failure during transportation, handling, installation and use. Liner compatibility must satisfy ASTM Method D5747, Compatibility Test for Wastes and Membrane Liners, or other compatibility test approved by the Department for the duration tank or other storage structure is used. Adjoining sections of liners shall be sealed together to prevent leakage in accordance with the manufacturer's directions. The integrity of all seams of the adjoining sections of liner shall be tested prior to use. Results of the tests shall be available upon request.

Prior to placing the tanks and approved aboveground containment structures on the secondary containment liner, the liner shall be inspected for lack of uniformity, damage and other imperfections that may cause the liner to leak. The operator shall correct damages or imperfections before placing the tanks on the liner.

If a liner becomes torn, or otherwise loses its integrity, tanks must be continuously monitored for leaks by onsite personnel while the liner is repaired. If repair of the liner is not practical or possible, the storage tank contents shall be removed and placed in another tank that meets the requirements of this section.

The operator shall notify the Department at least 3 business days before the installation of the liner. The notice shall be submitted electronically to the Department through its web site and include the date the liner will be installed. If the date of installation is extended, the operator shall renotify the Department with the date of installation. A licensed professional engineer or geologist that designed the site shall submit a statement on forms provided by the Department certifying that the liner, as built, is compliant with this section. This certification shall be submitted within 10 business days of installation of the liner.

(d) Tanks, series of tanks or other aboveground storage structures approved by the Department used to store brine or other fluids produced during operation of the well shall be designed, constructed and maintained to be structurally sound in accordance with sound engineering practices adhering to Nationally recognized industry standards and the manufacturer's specifications. Tanks that are manifolded together shall be designed in a manner to prevent the uncontrolled discharge of multiple manifolded tanks.

(e) Underground or partially buried storage tanks may not be used to store brine or other fluids produced during operation of the well ~~unless approved by the Department.~~ **All existing underground or partially buried storage tanks shall be removed by _____ (Editor's Note: The blank refers to ~~3-years~~ **1 year** after the effective date of adoption of this proposed rulemaking.).** A well operator utilizing underground or partially buried storage tanks as of _____, (Editor's Note: The blank refers to the effective date of adoption of this proposed rulemaking.) shall provide the Department with a list of the well sites where the underground or partially buried storage tanks are located and scheduled for removal of the tanks by _____ (Editor's Note: The blank refers to 6 months after the effective date of adoption of this proposed rulemaking.)

(f) All ~~new, refurbished or replaced~~ tanks **and approved aboveground containment structures that store brine or other fluid produced during operation of the well materials containing or contaminated with regulated substances** must comply with the applicable corrosion control requirements in §§ 245.531—245.534 (relating to corrosion and deterioration prevention). **Existing tank bottoms that do not meet the standards of § 245.531(b) shall be taken out of service and repaired or replaced to meet that standard before being returned to use. All existing tanks and approved aboveground containment structures must be evaluated by a corrosion expert by _____ (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking) and the corrosion expert's report must be provided to the Department. If the corrosion expert recommends installation of cathodic protection, lining, coating, or other corrosion control measures, the operator must make those repairs within Editor's Note: The blank refers to 18 months after the effective date of adoption of this proposed rulemaking).**

(g) All **existing**, new, refurbished or replaced tanks storing brine or other fluids produced during operation of the well must be reasonably protected from unauthorized acts of third parties. Unless the tank is surrounded by a fence, tank valves and access lids must utilize locks, open end plugs or removable handles and ladders on tanks must be retractable or other measures that prevent access by third parties.

§ 78.58 Onsite Processing

Proposed Regulation: The EQB proposes changes to § 78.58 for onsite processing.

Comment: We support deletion of alternative rules for pits constructed prior to July 29, 1989. We support the proposed notification and reporting requirements for the operator to keep the PADEP informed of onsite processing plans or transportation of materials to another well site.

We do not support the use of centralized impoundments because of the potential for air and water pollution as explained above.

We recommend that the operator provide more information in its notification to the PADEP about the procedures and tests used to characterize waste. This will ensure the waste is properly treated, handled, and disposed.

Pre-approval to aerate fluids should be limited to non-volatile materials and wastes. Aeration of volatile materials and wastes can contribute to air pollution, and should be conducted only in closed-loop tank systems capable of capturing air pollution and using vapors for power (preferably), or alternatively routing them to an incinerator or flare.

More specifically, we recommend the following changes to the proposed regulations at § 78.58:

§ 78.58. [Existing pits used for the control, storage and disposal of production fluids] Onsite processing.

[For pits in existence on July 29, 1989, the operator may request approval for an alternate method of satisfying the requirements of § 78.57(c)(2)(iii) (relating to control, storage and disposal of production fluids), the angle of slope requirements of § 78.57(c)(2)(v) and the liner requirement of § 78.57(c)(2)(vi)—(viii) by affirmatively demonstrating to the Department's satisfaction, by the use of monitoring wells or other methods approved by the Department, that the pit is impermeable and that the method will provide protection equivalent or superior to that provided by § 78.57. The operator shall request approval under § 78.57(c)(1).]

(a) The operator may request approval by the Department to process fluids generated by the development, drilling, stimulation, alteration, operation or plugging of oil or gas wells at the well site where the fluids were generated or at the well site where all of the fluid is intended to be beneficially used to develop, drill or stimulate a well. The request shall be submitted on forms provided by the Department and demonstrate that the processing operation will not result in pollution of land or waters of the Commonwealth.

(1) The operator shall provide the Department with a copy of the procedures and tests that will be used to characterize waste, to ensure it is properly treated, handled, and disposed.

(2) Onsite processing of volatile materials and wastes shall be conducted in closed-loop tank systems capable of capturing air pollution and using vapors for power (preferably), or, upon a showing of good cause, routing vapors to an incinerator or flare.

(b) Approval from the Department is not required for the following activities conducted at a well site ~~within lined containment areas or centralized impoundment permitted under § 78.59e (relating to centralized impoundments):~~

(1) Mixing fluids with freshwater.

(2) Aerating **of non-volatile** fluids.

(3) Filtering solids from fluids.

(c) The operator may request to process drill cuttings only at the well site where those drilling cuttings were generated by submitting a request to the Department for approval. The request shall be submitted on forms provided by the Department and demonstrate that the processing operation will not result in pollution of land or waters of the Commonwealth.

(d) Processing residual waste generated by the development, drilling, stimulation, alteration, operation or plugging of oil or gas wells other than as provided for in subsections (a) and (b) shall comply with the Solid Waste Management Act (35 P. S. §§ 6018.101—6018.1003).

(e) Processing of fluids in a manner approved under subsection (a) will be deemed to be approved at subsequent well sites provided the operator notifies the Department of location of the well site where the processing will occur prior to the beginning of processing operations. The notice shall be submitted electronically to the Department through its web site and include the date activities will begin.

(f) Sludges, filter cake or other solid waste remaining after the processing or handling of fluids under subsection (a) or (b), including solid waste mixed with drill cuttings, shall be characterized under § 287.54 (relating to chemical analysis of waste) before the solid waste leaves the well site.

§ 78.56, § 78.57, and § 78.58 Vapor Control

Our comments on proposed regulations § 78.56, § 78.57, and § 78.58 recommend that systems be installed to capture air pollution and route vapors to be sold or used for power (preferably), or alternatively to an incinerator or flare. The operator should be required to examine the technical and economic feasibility of using vapors for power, and only incinerate or flare when use as power is not feasible. Direct venting should be prohibited.

Gas flaring is environmentally preferable over venting because flaring reduces hazardous air pollutants (HAPs), Volatile Organic Compound (VOC) emissions, and Greenhouse Gas (GHG) emissions. When incineration or flaring is required, regulations should set an upper bound on the maximum volume of gas incinerated/flared. A minimum incinerator or flare efficiency of 98% should be required. The incinerator and flare systems should be designed in a manner that optimizes reliability, safety, and combustion efficiency. Requirements should include: minimizing the risk of pilot blowout by installing a reliable system; ensuring sufficient exit velocity or provide wind guards for low/intermittent velocity streams; ensuring use of a reliable ignition system; minimizing liquid carry-over and entrainment in the gas stream by ensuring a suitable liquid separation system is in place; and maximizing combustion efficiency by proper control and optimization of fuel/air/steam flow rates.

§ 78.59a Impoundment Embankments

Proposed Regulation: The EQB proposes a new design and construction standards for freshwater and centralized impoundments at § 78.59a.

Comment: We support improved design and construction standards for freshwater impoundments. We oppose the use of centralized impoundments for waste handling, as is explained above.

We recommend that § 78.59a and § 78.59b be combined into one regulation that addresses freshwater impoundments. However, for simplicity we have kept the freshwater impoundment embankment regulations (§ 78.59a) separate from the freshwater impoundment registration, performance, safety and security standards regulations (§ 78.59b) in our comments below. The regulations can be combined by the PADEP in the final draft.

Impoundments that include construction of embankments should be subject to the requirements of Chapter 105, Subchapter B, Dams and Reservoirs. Specifically, impoundments should be subject to the requirements of § 105.91 - § 105.99 related to classification and design criteria for approval of

construction, operation, modification, and maintenance; § 105.101 - § 105.109 related to construction requirements and procedures; § 105.111 related to the commencement of storage of water, fluid, or semifluid; § 105.123 related to the restoration of aquatic life; and § 105.131 - § 105.136 related to operation, maintenance, and emergencies.

We recommend that existing impoundments that do not meet these new standards be removed within one year from the date the regulations are approved, and be replaced to meet the new standard.

More specifically, we recommend the following changes to the proposed regulations at § 78.59a:

§ 78.59a. Freshwater Impoundments Eembankments.

New embankments constructed for freshwater impoundments for oil and gas activities shall meet the applicable requirements of 25 Pa. Code Chapter 105, Subchapter B. Dams and Reservoirs.

~~New embankments constructed for freshwater and centralized impoundments for oil and gas activities must meet the following requirements and any existing freshwater impoundments must meet these standards by _____ (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking.):~~

~~—(1) The foundation for each embankment must be stripped and grubbed to a minimum depth of 2 feet below existing contour prior to any placement and compaction of fill.~~

~~—(2) Any springs encountered in the embankment foundation area shall be drained to the downstream toe of the embankment with a drain section 2 foot by 2 foot in dimension consisting of PennDOT Type A sand, compacted by hand tamper. Geotextiles may not be used around sand. The last 3 feet of this drain at the downstream slope must be constructed of AASHTO #8 material.~~

~~—(3) The minimum top width of the embankment must be 12 feet.~~

~~—(4) The inside and outside slope must have a slope no steeper than 3 horizontal to 1 vertical.~~

~~—(5) Soils to be used for embankment construction must be classified in accordance with ASTM D-2487 (Unified Soils Classification). Soil samples must be classified at a minimum rate of 1 sample per 1,000 cubic yards of placed fill. Results of testing of materials shall be provided to the Department upon request.~~

~~—(6) The embankment must be constructed out of soils designated as GC, GM, SC, SM, CL or ML, only. Soils with split designations when one of the designations is not GC, GM, SC, SM, CL or ML may not be used. Soils must contain a minimum of 20% of No. 200 sieve materials or larger. Results of testing of materials shall be provided to the Department upon request.~~

~~—(7) Particles greater than 6 inches in any dimension may not be used for embankment construction.~~

~~—(8) Soil used in embankment construction must be compacted. Soil compaction shall be conducted in accordance with the following:~~

~~—(i) Compaction shall be conducted with a sheepsfoot or pad roller.~~

~~—(ii) The maximum loose lift thickness must be 9 inches.~~

~~—(iii) Soil shall be compacted until there is no visible nonmovement of the embankment material.~~

~~—(9) Exposed embankment slopes shall be permanently stabilized using one or a combination of the following methods:~~

~~—(i) Exposed embankments shall be limed, fertilized, seeded and mulched, and permanent vegetative ground covering in compliance with § 102.22 (relating to site stabilization) shall be established upon completion of construction of the impoundment.~~

~~—(ii) Compacted rockfill or riprap placed on the downstream face of the embankment as a cover having a minimum depth of 2 feet. The rockfill must be durable, evenly distributed and underlain by a Class 2, Type A geotextile.~~

§ 78.59b Freshwater Impoundments

Proposed Regulation: The EQB proposes new registration, performance, safety and security standards for freshwater impoundments at § 78.59b. The EQB also proposes to allow mine influenced water to be stored in “freshwater” impoundments.

Comment: We support improved registration, performance, safety, and security standards for freshwater impoundments. We oppose the use of centralized impoundments for waste handling, including mine influenced water, as explained above. We recommend that § 78.59a and § 78.59b be combined into one regulation that addresses freshwater impoundments.

We recommend that existing impoundments that do not meet these new standards be removed within one year from the date the regulations are approved, be replaced to meet the new standard.

We recommend improvements in the liner design, quality, installation, and maintenance requirements.

We do not support the storage of mine influenced water in a freshwater impoundment. A “freshwater” impoundment by its title is only designed to store uncontaminated “freshwater” that meets the definition that we proposed at § 78.15 above.⁵⁷ Mine influenced water should be handled as wastewater.

All water stored in a freshwater impoundment should be tested and verified to meet a “freshwater” standard prior to storage, and that test data should be provided to the PADEP.

We do not support § 78.59b(e), allowing for the artificial lowering of the seasonal high water table. The use of an artificial underdrain system is likely to affect the adjoining groundwater system beyond the impoundment, including potentially damaging impacts on wetlands and headwater streams through the lowering of the groundwater. Soil moisture conditions are almost certain to be affected by the centralized impoundment construction, and an artificial underdrain system would further exacerbate these impacts. Altered groundwater and soil moisture conditions will directly impact established woodland vegetation. Additionally, the presence of a seasonal high groundwater table indicates a hydrologic connection to adjacent streams and wetlands, and hence, an additional path for direct contamination, should a leak or discharge from the impoundment occur.

Chapter 73 of the Pennsylvania Code (related to Standards for On-lot Sewage Treatment Facilities) prohibits the installation of on-lot sewage facilities if the seasonal high water table is within 20 inches

⁵⁷ In our comments at § 78.15 above, we recommended that following definitions. Freshwater means “fresh surface water” and “fresh groundwater.” Fresh Groundwater means: “Uncontaminated water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials and all underground sources of drinking water, as defined in 40 CFR §§ 144.3, 146.4, including all primary and principal aquifers.” Fresh surface water means “Uncontaminated water in that portion of the generally recognized hydrologic cycle which occupies the surface of the Earth.”

(§ 73.14(5)). There is no option for an alternate underdrain system if a seasonal high-water table condition exists. The same standards should apply to impoundments.

Impoundments should not be permitted within 20 inches of a seasonal high groundwater table, and should not be allowed to artificially lower the seasonal high groundwater table. The water quality implications from an impoundment can be far more significant than an on-lot sewage treatment system; the standards should not be less stringent.

We do not support impoundment site waivers, even if the landowner consents. Sites must be fully restored to protect interconnected water supplies, forests, and habitats. The impoundment site should be restored based on a survey of existing conditions prior to disturbance, to ensure that the ecological integrity and habitat values of a forested or naturally vegetated area are fully restored. Impoundments require maintenance and inspection for continued safety of the structure, and the landowner may not be fully aware of these requirements. The required removal of the liner will alter the impoundment capacity to retain water and the impoundment structure itself. The PADEP should require restoration to original contours.

More specifically, we recommend the following changes to the proposed regulations at § 78.59 (b):

§ 78.59b. Freshwater impoundments.

Impoundments may be constructed for freshwater (as defined in § 78.15). Only freshwater may be stored in a freshwater impoundment. Centralized waste impoundments are prohibited.

(a) In addition to meeting the requirements of § 78.59a (relating to impoundment embankments), **all new** freshwater impoundments must be in compliance with this section and **any existing freshwater impoundments must meet these standards by _____ (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking.)**

(b) A well operator that constructed a freshwater impoundment shall register the location of the freshwater impoundment by _____, (Editor's Note: The blank refers to 60 days after the effective date of adoption of this proposed rulemaking.) by providing the Department, in writing, with the GPS coordinates, township and county where the freshwater impoundment is located. A well operator shall register the location of a new freshwater impoundment prior to construction. Registration of the freshwater impoundment may be transferred to another operator. Registration transfers shall utilize forms provided by the Department.

(c) Freshwater impoundments shall be constructed with a synthetic impervious liner.

(d) Unless **an individual the operator or its contract staff** is continuously present at a freshwater impoundment, a fence must completely surround the freshwater impoundment to prevent unauthorized acts of third parties and damage caused by wildlife.

~~—(e) The bottom of the impoundment must be at least 20 inches above the seasonal high groundwater table. The applicant may maintain the required separation distance of 20 inches by artificial means such as an under-drain system throughout the lifetime of the impoundment. In no case shall the regional groundwater table be affected. The operator shall document the depth of the seasonal high groundwater table, the manner in which the depth of the seasonal high groundwater table was ascertained, the distance between the bottom of the impoundment and the seasonal high groundwater table, and the depth of the regional groundwater table if the separation between the impoundment bottom and seasonal high groundwater table is maintained by artificial means. The~~

~~operator shall submit records demonstrating compliance with this subsection to the Department upon request.~~

(f) Freshwater impoundments shall be restored by the operator ~~so that the impoundment is registered to~~ by removing excess water and the synthetic liner and returning the site to approximate original baseline conditions to ensure that the ecological integrity and habitat values of a forested or naturally vegetated area are fully restored, including preconstruction contours, and can support the land uses that existed prior to oil and gas activities to the extent practicable within 9 months of completion of drilling the last well serviced by the impoundment. A 2-year restoration extension may be requested under section 3216(g) of the act (relating to well site restoration). If written consent is obtained from the landowner, the requirement to return the site to approximate original contours may be waived by the Department if the liner is removed from the impoundment.

~~—(g) Prior to storing mine influenced water in a freshwater impoundment, the operator shall develop a mine influenced water storage plan and submit it to the Department for approval.~~

~~—(1) The mine influenced water storage plan shall be submitted on forms provided by the Department and include the following:~~

~~—(i) A demonstration that the escape of the mine influenced water stored in the freshwater impoundment will not result in air, water or land pollution, or endanger persons or property.~~

~~—(ii) A procedure and schedule to test the mine influenced water. This testing shall be conducted at the source prior to storage in the impoundment.~~

~~—(iii) A records retention schedule for the mine influenced water test results.~~

~~—(2) An operator with an approved mine influenced water storage plan shall maintain records of all mine influenced water testing prior to storage. These records shall be made available to the Department upon request.~~

(h) The ~~Department may require the~~ operator shall ~~to~~ test water sources proposed to be stored in a freshwater impoundment prior to storage to verify that the water quality meets the § 78.15 freshwater standard. The water test data must be provided to the Department 10 days prior to storing freshwater in the freshwater impoundment.

§ 78.59c Centralized Impoundments

Proposed Regulation: The EQB proposes new requirements for centralized impoundments at § 78.59c.

Comment: We oppose the use of centralized impoundments for waste handling. The PADEP can promote recycling, reduce the need for freshwater, and reduce disposal requirements without permitting centralized impoundments. We recommend that § 78.59c be deleted in its entirety and replaced with the text indicated below.⁵⁸

§ 78.59c. Centralized Impoundments.

Centralized impoundments, as defined in this chapter and used to hold contaminated fluids or semi-fluids associated with oil and gas activities are prohibited. All existing centralized

⁵⁸ In the event that the EQB rejects our recommendation that it prohibit centralized impoundments for anything other than freshwater, as we define that term above, we ask that it adopt the alternative suggestions in Appendix A with respect to the proposed regulation of centralized impoundments.

impoundments must be removed and the impoundment site remediated by _____ (Editor's Note: The blank refers to one year after the effective date of adoption of this proposed rulemaking).

§ 78.60 Discharge Requirements

Proposed Regulation: The EQB proposes additional clarifications and requirements at § 78.60(b) relating to discharge of tophole water to land.

Comment: We do not support discharge of tophole water, unless it meets the standard of “uncontaminated freshwater.” Tophole water that is contaminated must be classified, handled, and disposed of as “wastewater.” We recommend, therefore, that the quality of tophole water and precipitation that accumulates in clean, uncontaminated storage areas be tested and verified prior to discharge and that the test data be provided to the PADEP.

We do not support the use of a sheen test to determine whether tophole water can be discharged to land. Water can contain some amount of oil and grease and still pass a sheen test. Water also can contain contaminants that do not leave a sheen. Water discharged to land must contain no oil or grease at all or any other contaminant introduced by Oil and Gas Operations.

The waiver provision of § 78.60(b)(7) must be deleted, and the wetland setback must be retained, pursuant to the Pennsylvania Supreme Court’s recent decision in *Robinson Township v. Pa.*, 2013 WL 6687290. See our transmittal letter for additional legal argument in support of this comment.

We recommend the following changes to the discharge requirements at § 78.60.

§ 78.60. Discharge requirements.

(a) The owner and operator may not cause or allow a discharge of a substance, **fill or dredged material** to the waters of this Commonwealth unless the discharge complies with this subchapter and Chapters 91—93, 95 **[and]**, 102 **and** 105, The Clean Streams Law (35 P. S. §§ 691.1—691.1001), **the Dam Safety and Encroachments Act (32 P. S. §§ 693.1—693.27)** and the act.

(b) The owner and operator may **not** discharge tophole water or **water in a pit as a result of precipitation that accumulates in clean, uncontaminated storage areas** by land application **unless only if** the discharge is in accordance with the following requirements:

(1) **Tophole water shall not contain any of the following in excess of Pennsylvania Safe Drinking Water Act standards: No additives, chemicals, brine, oil, grease, drilling muds, pollution materials, regulated substances, Naturally Occurring Radioactive Material (NORM), Technologically Enhanced Naturally Occurring Radioactive Material (TENORM), or other toxins, or any drilling fluids other than gases air or fresh water that have been added to or are contained in the water, unless otherwise approved by the Department.**

(2) The pH is not less than 6 nor greater than 9 standard units, or is characteristic of the natural background quality of the groundwater.

(3) The specific conductance of the discharge is less than 1,000 µmHos/cm.

~~(4) There is no sheen from oil and grease.~~

(5) The discharge water shall be spread over an undisturbed, vegetated area capable of absorbing the tophole water and filtering solids in the discharge, and spread in a manner that prevents a direct discharge to surface waters and complies with § 78.53 (relating to erosion and sedimentation control).

(6) Upon completion, the area complies with § 78.53.

(7) The area of land application is not within 200 feet of a water supply or within 100 feet of a [stream,] watercourse, ~~or~~ body of water, ~~for a wetland~~ ~~unless approved as part of a waiver granted by the Department under section [205(b) of the act (58 P. S. § 601.205(b))] 3215(b) of the act (relating to well location restrictions).~~

(8) If the water does not meet the requirements of paragraph (1-2 ~~or~~ through 4), ~~the Department may approve treatment prior to~~ discharge to the land surface ~~is prohibited~~.

(9) The operator shall test water proposed to be discharged prior to discharge to verify that the water quality meets the § 78.60 standards. The water test data must be provided to the Department within 7 days of the test.

(c) Compliance with subsection (b) shall be documented by the operator and made available to the Department ~~upon request~~ while conducting activities under subsection (b) and submitted under § 78.65(f)(1) (relating to site restoration).

§ 78.61 Disposal of Drill Cuttings

Proposed Regulation: The EQB proposes additional clarifications and requirements at § 78.61 for land application of drill cuttings and proposes to allow onsite disposal of contaminated drill cuttings.

Comment: We oppose the land application of all drill cuttings. We oppose long-term onsite burial of any drill cuttings generally contaminated with chemicals, oil, grease, pollutional materials, regulated substances, water-based drilling muds that contain chemical additives, oil-based drilling muds, polymer-based drilling muds containing mineral oil lubricants, NORM, TENORM, mercury, heavy metals, and other chemical additives or toxins.

Contaminated drill cuttings should not be buried onsite or applied to the land surface. Drilling waste should be removed from the drilling location and properly disposed of at an approved waste disposal facility capable of handling the quantity and type of waste generated.

The use of closed-loop tank systems to handle and store drilling muds and cuttings, and disposal of this waste at an offsite approved waste treatment facility is a best practice, as explained above.

It is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drill cuttings and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system to collect the drill cuttings, because the cuttings can be directly transported to a waste handling facility.

A closed-loop tank system offers the following advantages:

- Eliminates the time and expense associated with reserve pit construction and reclamation;
- Reduces the surface disturbance associated with the well pad;
- Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;
- Lowers mud replacement costs by capturing and re-circulating drilling mud;
- Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and,

- Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.⁵⁹

Long-term disposal options for contaminated drill cuttings include disposal at a lined solid waste treatment facility that is designed for and capable of safely treating and disposing of the waste, or Cuttings Reinjection (CRI) Technology can be used to inject drill cutting waste into a subsurface disposal well approved by USEPA.

CRI Technology, also referred to as “grind-and-inject technology,” is commonly used by industry as a best practice to avoid the need for long-term onsite burial of drill cuttings. CRI technology converts drill cuttings into a slurry that can be injected into a subsurface disposal well. CRI also provides a waste disposal method for used drilling mud, because mud can be used in the slurry formulation to reduce supplemental water needs.

CRI is commonly used in Alaska as a best practice to avoid use of long-term reserve pit use and surface burial of contaminated drill cuttings. Waste is collected, ground into a slurry, and injected into a subsurface disposal well.⁶⁰ If an injection well is not available at a well location, operators have collected wastes and transported them back to an injection well location. Operators that do not have their own waste handling facilities or disposal wells typically negotiate an agreement with another operator or a service provider to use its disposal facilities. As a result of this best practice implementation in Alaska, DOE reports there are 58 active Class II-D (disposal) wells and six Class I wells in Alaska.⁶¹

Ohio and Texas have both determined that deep injection of produced water and drilling waste is the preferred disposal option.⁶²

In addition to the environmental mitigation benefit, CRI technology reduces future liability for industry operators, and has been determined to be an environmentally-appropriate method for handling drilling waste containing NORM or TENORM by several major operators.⁶³

International operators report favorable economics for eliminating exploration and production waste by deep well injection. For example, a 2001 Advantek International Corp. report concludes:

Downhole disposal of mud and cuttings waste through hydraulic fracturing provides a zero discharge solution and eliminates future cleanup liabilities... This downhole disposal technology has shown success in both onshore and offshore drilling operations and is

⁵⁹ D. Rogers, et al., *Closed-Loop Drilling System: A Viable Alternative to Reserve Waste Pits*, World Oil, Volume 227, No. 12, December 2006, <http://www.worldoil.com/December-2006-Closed-loop-drilling-system-A-viable-alternative-to-reserve-waste-pits.html>.

⁶⁰ BP Exploration (Alaska), Inc., ARCO Alaska, Inc. and ConocoPhillips, Inc. have published numerous technical papers on grind and injection technology, and the success of disposal wells as a pollution prevention measure in the SPE trade journals, and at industry conferences.

⁶¹ M.G. Puder, et al., *Argonne National Laboratory, Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes* 17 (Feb. 2003) (prepared for the U.S. Dep't of Energy).

⁶² Groundwater Protection Council, *Groundwater Investigations, and their Role in Advancing Regulatory Reforms. A Two-State Review: Ohio and Texas* (Aug. 2011).

⁶³ A. Okorodudu, et al., *Feasibility Study of Cuttings-Injection Operation: A Case Study of the Niger Delta Basin 2* (Apr. 2006) (SPE Paper 98640, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production in Abu Dhabi, U.A.E.).

becoming a routine disposal option...It also offers favorable economics [emphasis added].⁶⁴

The U.S. Department of Energy (DOE) also advocates CRI technology:

Because wastes are injected deep into the earth below drinking water zones, proper slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods.⁶⁵

In 1990, the United States passed the Pollution Prevention Act, establishing a national policy that places priority on pollution prevention and specifies that disposal into the environment should only be allowed as a **last resort**:

*The Congress hereby declares it to be the national policy of the United States that pollution should be prevented or reduced at the source whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and **disposal or other release into the environment should be employed only as a last resort** and should be conducted in an environmentally safe manner[emphasis added].⁶⁶*

Additionally, the amount of drill-cutting waste generated can be significant. If CRI technology is not used to dispose of this waste by deep well injection, then surface waste disposal sites will need to be utilized to handle this waste because several hundred cubic yards of drill cutting waste can be produced from each well.

We recommend the following changes to the discharge requirements at § 78.61.

§ 78.61. Disposal of drill cuttings.

(a) **Closed-loop tank systems shall be used to handle and store drilling muds and cuttings. All drill cuttings must be disposed of at an offsite approved waste disposal facility or injected into an EPA-approved subsurface waste disposal well using cuttings reinjection technology.**

(b) Disposal of all drilling muds and drill cuttings, regardless if from above or below the surface casing seat, in pits is prohibited.

~~*Drill cuttings from above the casing seat—pits. The owner or operator may dispose of drill cuttings from above the casing seat determined in accordance with [§ 78.83(b)] § 78.83(c) (relating to surface and coal protective casing and cementing procedures) in a pit at the well site if the owner or operator satisfies the following requirements:*~~

~~—(1) The drill cuttings are generated from the well at the well site.~~

~~—(2) The drill cuttings are not contaminated with [pollutional material] a regulated substance, including brines, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids or drilling fluids other than tophole water, fresh water or gases.~~

⁶⁴ A. Abou-Sayed, et al., *Design Considerations in Drill Cuttings Re-Injection Through Downhole Fracturing* 1 (Oct. 2001) (IADC/SPE Paper 72308, presented at the IADC/SPE Middle East Drilling Technology Meeting in Bahrain).

⁶⁵ Argonne National Laboratory, *An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes* 2 (Sept. 2003) (publication prepared for the U.S. Department of Energy).

⁶⁶ Pollution Prevention Act of 1990, 42 U.S.C. ch. 133.

- ~~—(3) The disposal area is not within 100 feet of a [stream, body of water or wetland] watercourse or body of water unless approved as part of a waiver granted by the Department under section [205(b) of the act (58 P. S. § 601.205(b))] 3215(b) of the act (relating to well location restrictions).~~
- ~~—(4) The disposal area is not within 200 feet of a water supply.~~
- ~~—(5) The pit is designed, constructed and maintained to be structurally sound.~~
- ~~—(6) The free liquid fraction of the waste shall be removed and disposed under § 78.60 (relating to discharge requirements).~~
- ~~—(7) The pit shall be backfilled to the ground surface and graded to promote runoff with no depression that would accumulate or pond water on the surface. The stability of the backfilled pit shall be compatible with the adjacent land.~~
- ~~—(8) The surface of the backfilled pit area shall be revegetated to stabilize the soil surface and comply with § 78.53 (relating to erosion and [sedimentation] sediment control). The revegetation shall establish a diverse, effective, permanent, vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface of the landowner, the surface shall be stabilized against erosion.~~
- ~~—(b) *Drill cuttings from above the casing seat—land application.* The owner or operator may dispose of drill cuttings from above the casing seat determined in accordance with [§ 78.83(b)] § 78.83(c) by land application at the well site if the owner or operator satisfies the following requirements:~~
 - ~~—(1) The drill cuttings are generated from the well at the well site.~~
 - ~~—(2) The drill cuttings are not contaminated with [pollutional material] a regulated substance, including brines, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids or drilling fluids other than tophole water, fresh water or gases.~~
 - ~~—(3) The disposal area is not within 100 feet of a [stream,] watercourse or body of water [or wetland] unless approved as part of a waiver granted by the Department under section [205(b) of the act (58 P. S. § 601.205(b))] 3215(b) of the act.~~
 - ~~—(4) The disposal area is not within 200 feet of a water supply.~~
 - ~~—(5) The soils have a minimum depth from surface to bedrock of 20 inches.~~
 - ~~—(6) The drill cuttings are not spread when saturated, snow covered or frozen ground interferes with incorporation of the drill cuttings into the soil.~~
 - ~~—(7) The drill cuttings are not applied in quantities which will result in runoff or in surface water or groundwater pollution.~~
 - ~~—(8) The free liquid fraction is disposed in accordance with § 78.60.~~
 - ~~—(9) The drill cuttings are spread and incorporated into the soil. The loading and application rate of drill cuttings may not exceed a maximum of drill cuttings to soil ratio of 1:1.~~
 - ~~—(10) The land application area shall be revegetated to stabilize the soil surface and comply with § 78.53. The revegetation shall establish a diverse, effective permanent vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface by the landowner, the surface shall be stabilized against erosion.~~
- ~~—(c) *Drill cuttings from below the casing seat.* After removal of the free liquid fraction and disposal in accordance with § 78.60, drill cuttings from below the casing seat determined in accordance with [§ 78.83(b)] § 78.83(c) may be disposed of as follows:~~

- ~~—(1) In a pit that meets the requirements of [§ 78.62(a)(5)–(18)] § 78.62(a)(5)–(16) and (b) (relating to disposal of residual waste—pits).~~
- ~~—(2) By land application in accordance with § 78.63(a)(5)–(20) and (b) (relating to disposal of residual waste—land application).~~
- ~~—(d) The owner or operator may request to use solidifiers, dusting, unlined pits, attenuation or other alternative practices for the disposal of uncontaminated drill cuttings by submitting a request to the Department for approval. The request shall be made on forms provided by the Department and shall demonstrate that the practice provides equivalent or superior protection to the requirements of this section. The Department will maintain a list of approved solidifiers on its web site. The operator does not need to request approval from the Department for use of approved solidifiers.~~
- ~~—(e) A pit used for the disposal of residual waste, including contaminated drill cuttings, shall comply with § 78.62. Land application of residual waste, including contaminated drill cuttings, shall comply with § 78.63.~~
- ~~—(f) The owner or operator shall notify the Department at least 3 business days before disposing of drill cuttings under this section. This notice shall be submitted electronically to the Department through its web site and include the date the cuttings will be disposed. If the date of disposal is extended, the operator shall renotify the Department of the date of disposal, which does not need to be 3 business days in advance.~~

§ 78.62 Disposal of Residual Waste - Pits

Proposed Regulation: The EQB proposes amendments to § 78.62 to clarify that solid waste generated by hydraulic fracturing of unconventional wells or processing wastewater under § 78.58 (relating to onsite processing) may not be disposed of in a pit on the well site. However, the EQB proposes to allow residual waste, including contaminated drill cuttings, to be disposed of in a pit at the well site.

Comment: We oppose long-term onsite burial of any residual waste contaminated with chemicals, oil, grease, pollutional materials, regulated substances, water-based drilling muds that contain chemical additives, oil-based drilling muds, polymer-based drilling muds containing mineral oil lubricants, NORM, TENORM, mercury, heavy metals, and other chemical additives or toxins.

Contaminated drill cuttings should not be buried onsite or applied to the land surface. Drilling waste should be removed from the drilling location and properly disposed of at an approved waste disposal facility capable of handling the quantity and type of waste generated.

Alternative best practices for waste handling are described in our § 78.61 comments above.

We recommend the following changes to the discharge requirements at § 78.62.

§ 78.62. Disposal of residual waste—pits.

(a) Closed-loop tank systems shall be used to handle and store residual waste. All residual waste must be disposed of at an offsite approved waste disposal facility.

~~(a) After the removal and disposal of the free liquid fraction of the waste under § 78.60(a) (relating to discharge requirements), the owner or operator may dispose of residual waste, including~~

~~contaminated drill cuttings, in a pit at the well site if the owner or operator satisfies the following requirements:~~

~~(1) The residual waste is generated by the drilling, or stimulation [or production] of an oil or gas well that is located on the well site where the residual waste is disposed. Solid waste generated by hydraulic fracturing of unconventional wells and solid waste generated by processing of fluids pursuant to § 78.58, may not be disposed of on the well site.~~

~~(2) The well is permitted under section [201] 3211 of the act [(58 P. S. § 601.201)] (58 Pa.C.S. § 3211) or registered under section [203] of the act (58 P. S. § 601.203).~~

~~(3) The requirements of section [215] 3225 of the act [(58 P. S. § 601.215)] (58 Pa.C.S. § 3225) are satisfied by filing a surety or collateral bond for wells drilled on or after April 18, 1985.~~

~~(4) Compliance is maintained with the act and this title.~~

~~(5) The owner or operator shall notify the Department at least 3 business days before disposing residual waste according to this section. This notice shall be submitted electronically to the Department through its website and include the date the residual waste will be disposed. If the date of disposal changes, the operator shall re-notify of the new proposed date of disposal.~~

~~[(5)] (6) The disposal area is not within 200 feet measured horizontally from an existing building, unless the current owner thereof has provided a written waiver consenting to the disposal closer than 200 feet. The waiver shall be knowingly made and separate from a lease or deed unless the lease or deed contains an explicit waiver from the current owner.~~

~~[(6)] (7) The disposal area is not within 100 feet of a [stream,] watercourse or body of water [or wetland].~~

~~[(7)] (8) The disposal area is not within 200 feet of a water supply.~~

~~[(8)] (9) The bottom of the pit is a minimum of 20 inches above the seasonal high groundwater table. The well operator shall determine that the pit bottom is at least 20 inches above the seasonal high groundwater table prior to using the pit. The determination shall be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The individual's determination shall contain a statement certifying that the pit bottom is at least 20 inches above the seasonal high groundwater table according to observed field conditions. The name, qualifications and statement of the individual making the determination and the basis of the determination shall be provided to the Department upon request.~~

~~[(9)] (10) The pit is designed, constructed and maintained to be structurally sound and impermeable.~~

~~[(10)] (11) The pit and liner meet the requirements of 78.56 (a)(8)-(10). [is lined with a synthetic flexible liner that is compatible with the waste and has a coefficient of permeability of no greater than 1×10^{-7} cm/sec. The liner shall be of sufficient strength and thickness to maintain the integrity of the liner. The liner thickness shall be at least 30 mils.~~

~~Adjoining sections of liners shall be sealed together in accordance with the manufacturer's directions to prevent leakage. The operator may use an alternate liner or natural materials, if the material and the installation procedure to be used are approved by the Department.~~

~~Notice of the approved liners and installation procedures will be published by the Department in the *Pennsylvania Bulletin*.~~

~~(12) The liner shall be designed, constructed and maintained so that the physical and chemical characteristics of the liner are not adversely affected by the waste and the liner is resistant to~~

~~physical, chemical and other failure during transportation, handling, installation and use. Liner compatibility shall satisfy EPA Method 9090, *Compatibility Test for Wastes and Membrane Liners*, or other documented data approved by the Department.~~

~~(13) The pit shall be constructed so that the liner subbase is smooth, uniform and free of debris, rock and other material that may puncture, tear, cut, rip or otherwise cause the liner to fail. The liner subbase and subgrade shall be capable of bearing the weight of the material above the liner without settling. If the pit bottom or sides consist of rock, shale or other material that may cause the liner to fail and leak, a subbase of at least 6 inches of soil, sand or smooth gravel, or sufficient amount of an equivalent material shall be installed over the area as the subbase for the liner.~~

~~(14) Prior to placing material in the pit, the liner shall be inspected for lack of uniformity, damage and other imperfections that may cause the liner to leak. The owner or operator shall correct damages or imperfections before placing waste in the pit, and shall maintain the pit until closure of the pit.~~

~~[(14)] (12) Prior to encapsulating the residual waste within the liner, the free liquid fraction of the residual waste shall be removed and disposed under § 78.60(a).~~

~~[(15)] (13) The liner shall be folded over, or an additional liner shall be added, to completely cover the residual waste and the residual waste is shaped so that water does not infiltrate the liner and is not confined above the liner.~~

~~[(16)] (14) Puncturing or perforating the liner is prohibited.~~

~~[(17)] (15) The pit shall be backfilled to at least 18 inches over the top of the liner and graded to promote runoff with no depressions that would accumulate or pond water on the surface. The stability of the backfilled pit shall be compatible with the adjacent land.~~

~~[(18)] (16) The surface area of the backfilled pit area shall be revegetated to stabilize the soil surface and comply with § 78.53 (relating to erosion and sediment [ation] control). The revegetation shall establish a diverse, effective permanent vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface by the landowner, the surface shall be stabilized against erosion.~~

~~(b) A person may not dispose of residual waste, including contaminated drill cuttings, at the well site unless the residual waste meets the following requirements:~~

~~(1) The concentration of contaminants in the leachate from the residual waste does not exceed 50% of the maximum concentration in 40 C.F.R. § 261.24 Table I (relating to characteristic of toxicity).~~

~~(2) The concentration of contaminants in the leachate from the residual waste does not exceed 50 times the primary maximum contaminant level in effect under § 109.202 (relating to State MCLs, MRDLs and treatment technique requirements).~~

~~(3) For other health related contaminants, the concentration of contaminants in the leachate from the residual waste does not exceed 50 times the safe drinking water level established by the Department.~~

~~(4) Leachate characteristics are determined in accordance with methods approved by the Department.~~

~~(c) The owner or operator may request to use solidifiers or other alternate practices for the disposal of residual waste, including contaminated drill cuttings, by submitting a request to the Department for approval. The request shall be made on forms provided by the Department and~~

~~shall demonstrate that the practice provides equivalent or superior protection to the requirements of this section.~~

§ 78.63 Disposal of Residual Waste – Land Application

Proposed Regulation: The EQB proposes additional requirements at § 78.63 to clarify that solid waste generated by hydraulic fracturing of unconventional wells or processing of fluids under § 78.58 to may not be disposed of by land application at the well site, but that residual waste (including contaminated drill cuttings) may be disposed of at the well site by land application.

Comment: We support the EQB's proposal to prohibit land disposal of solid waste generated by hydraulic fracturing of unconventional wells or processing of fluids under § 78.58.

However, we oppose the land application of any other oil and gas waste, and we do not support the EQB's proposal to allow the land application of residual waste (including **contaminated** drill cuttings). We also do not support the distinction made here between unconventional and other oil and gas wells; this rule should apply to all wells in Pennsylvania.

We oppose the long-term onsite burial of any waste contaminated with chemicals, oil, grease, pollutional materials, regulated substances, water based drilling muds that contain chemical additives, oil-based drilling muds, polymer-based drilling muds containing mineral oil lubricants, NORM, TENORM, mercury, heavy metals, or any other chemical additives or toxins.

We recommend that § 78.63 be revised as follows:

§ 78.63. Disposal of **residual** waste **prohibited**—land application.

(a) The owner or operator **is prohibited from disposing of any waste from Oil and Gas Operations by land application.**

~~may dispose of residual waste, including contaminated drill cuttings, at the well site by land application of the waste if the owner or operator satisfies the following requirements:~~

~~—(1) The residual waste is generated by the drilling [or production] of an oil or gas well that is located on the well [side] site. Residual waste generated by hydraulic fracturing of unconventional wells and residual waste generated by processing under § 78.58 (relating to onsite processing) may not be disposed of by land application.~~

~~—(2) The well is permitted under section [201 of the act (58 P. S. § 601.201)] 3211 of the act (relating to well permits) or registered under section [203 of the act (58 P. S. § 601.215)] 3213 of the act (relating to well registration and identification).~~

~~—(3) The requirements of section [215 of the act (58 P. S. § 601.215)] 3225 of the act (relating to bonding) are satisfied by filing a surety or collateral bond for wells drilled on or after April 18, 1985.~~

~~—(4) Compliance with the act and this title is maintained.~~

~~—(5) The owner or operator shall notify the Department electronically through its web site at least 3 [working] business days before the land application activity is to occur. The notification must include the date on which the land application is to occur. If the date of land application is extended, the operator shall renotify the Department of the new proposed date, which does not need to be 3 business days in advance.~~

~~*****~~

~~—(20) The land application area shall be revegetated to stabilize the soil surface and comply with [§ 78.53] Chapter 102 (relating to erosion and [sedimentation] sediment control). The revegetation shall establish a diverse, effective permanent vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface by the landowner, the surface shall be stabilized against erosion.~~

~~—(21) If [a chemical] additional analysis conducted under paragraph (19) fails to show compliance with [paragraph (18)] this section, the owner or operator shall remediate the land application area until compliance is demonstrated.~~

~~—(b) A person may not dispose of residual waste, including contaminated drill cuttings, at the well site unless the concentration of contaminants in the leachate from the waste does not exceed the maximum concentration stated in [§ 261.24 Table I (relating to characteristic of toxicity)] 40 CFR 261.24, Table 1 (relating to maximum concentration of contaminants for the toxicity characteristic).~~

~~—(c) The owner or operator may request to dispose of residual waste, including contaminated drill cuttings, in an alternate manner from that required in subsection (a) by submitting a request to the Department for approval. The request shall be made on forms provided by the Department and shall demonstrate that the practice provides equivalent or superior protection to the requirements of this section.~~

~~—(d) The operator shall document compliance with subsection (b) and be made available to the Department upon request while conducting activities under subsection (a) and submitted under § 78.65(f)(7) (relating to site restoration).~~

§ 78.64a Containment Systems and Practices at Unconventional Well Sites

Proposed Regulation: The EQB proposes new containment systems and practices at unconventional wells sites (§ 78.64a).

Comment: We support proposals to improve containment systems and practices. Overall, this new section provides a number of positive spill prevention requirements. We do, however, have some recommendations for improvement.

Foremost, we recommend that containment systems and practices should be improved at all oil and gas operations, not just unconventional well sites, and the containment systems should be impervious and impermeable. The proposed regulation would allow some permeability through the containment liner, albeit a small coefficient of permeability is proposed. However, we request that no amount of leakage be allowed. Containment systems should be “leak proof.”

When a containment system is damaged, the operator should be required to immediately remove regulated substances from that damaged containment system.

We recommend that § 78.64a be revised as follows:

§ 78.64a. Containment systems and practices at Oil and Gas Operations~~unconventional well sites~~.

(a) This section applies to ~~unconventional~~all Oil and Gas Operations.

(b) All Oil and Gas Operations and well sites shall be designed and constructed using containment systems and practices that prevent spills of regulated substances to the ground surface and to prevent spills from leaving the Oil and Gas Operation well-site.

(c) All regulated substances, including solid wastes and other regulated substances in equipment or vehicles, shall be managed within a containment system. This subsection does not apply to fuel stored in equipment or vehicle fuel tanks unless the equipment or vehicle is being refueled at the well site.

~~—(d) Pits and centralized impoundments that comply with this chapter are deemed to meet the requirements of this section.~~

(e) Containment systems must meet all of the following:

(1) A containment system must be used ~~on the well site at the Oil and Gas Operation~~ when any equipment that will be used for any phase of drilling, casing, cementing, hydraulic fracturing or flowback operations is brought onto a well site and when regulated substances including drilling mud, drilling mud additives, hydraulic oil, diesel fuel, hydraulic fracturing additives, chemicals, or flowback are brought onto or generated at the well-site Oil and Gas Operation.

(2) A containment system must be impervious and impermeable. ~~have a coefficient of permeability no greater than 1×10^{-10} cm/sec~~

(3) The physical and chemical characteristics of all liners, coatings or other materials used as part of the containment system, that could potentially come into direct contact with regulated substances being stored, must be compatible with the regulated substance and be resistant to physical, chemical and other failure during handling, installation and use. Liner compatibility shall satisfy ASTM Method D5747, Compatibility Test for Wastes and Membrane Liners, or other more stringent standards as approved by the Department.

(f) An operator shall utilize secondary containment when storing additives, chemicals, oils or fuels, or regulated substances. The secondary containment must have sufficient containment capacity to hold the volume of the largest container within the secondary containment area plus 10% to allow for precipitation, unless the container is equipped with individual secondary containment such as a double walled tank. Where double-walled tanks are used, a secondary containment liner must be placed under all valves, flanges, and connection points to capture potential leaks.

Tanks that are manifolded together shall be designed in a manner to prevent the uncontrolled discharge of multiple manifolded tanks. A well site liner that is not used in conjunction with other containment systems does not constitute secondary containment for the purpose of this subsection.

(g) Subsurface secondary containment systems may be employed at the well-site Oil and Gas Operation. Subsurface secondary containment must meet the following requirements:

(1) Subsurface secondary containment systems must be impervious, impermeable and have have a coefficient of permeability of no greater than 1×10^{-10} cm/sec with sufficient strength and thickness to maintain the integrity of the containment system. The thickness of a subsurface containment system must be at least 30 mils. Adjoining sections of the subsurface containment system must be sealed together, in accordance with the manufacturer's directions, to prevent leakage. All seams of the adjoining sections shall have their integrity tested prior to being covered.

(2) Subsurface secondary containment systems must be designed to allow for the management or removal of stormwater.

(3) Subsurface secondary containment systems must be designed and installed in a manner that prevents damage to the system by the sub-base or the movement of equipment or other activities on the surface.

(4) Subsurface secondary containment systems may not be used to store regulated substances.

(5) A written standard of operational procedure for the inspection, maintenance and repair of the subsurface secondary containment system shall be included in the preparedness, prevention and contingency plan.

(h) **The operator shall submit a report to the Department documenting compliance with § 78.64 within 30 days of installation of the containment system and at least 14 days prior to operation. The Department shall make the report available to the public on the Department's website within 7 days.** All surface containment systems shall be inspected weekly to ensure integrity. If the containment system is damaged or compromised, the **well** operator shall **immediately** repair the containment system. **If the containment system cannot be immediately repaired, all regulated substances must be removed from the containment system and removed from the site, or placed in another on-site containment system that has not been damaged. If as soon as practicable.** The **well** operator shall maintain records of any repairs until the **well-site containment system** is restored. Stormwater shall be removed as soon as possible and prior to the capacity of secondary containment being reduced by 10% or more.

(i) Regulated substances that escape from primary containment or are otherwise spilled onto a containment system shall be **cleaned up and** removed **as soon as possible within 24 hours**. After removal of the regulated substances the operator shall inspect the containment system. A Department-approved leak detection system capable of rapidly detecting a leak shall satisfy the requirement to inspect the integrity of a subsurface containment system. Groundwater monitoring wells do not constitute a leak detection system for the purpose of this subsection. If the containment system did not completely contain the material, the operator shall notify the Department, **all regulated substances shall be removed from the containment system and removed from the site, or placed in another on-site containment system that has not been damaged,** and the **operator shall immediately** remediate the affected area in accordance with § 78.66 (relating to reporting and remediating releases).

(j) Stormwater that comes into contact with regulated substances stored within the secondary containment area shall be managed as residual waste.

(k) Inspection reports and maintenance records shall be available at the well site for review by the Department, **shall be submitted to the Department annually, and shall be made available to the public on the Department's website within 7 days.**

(l) Documentation of chemical compatibility of containment systems with material stored within the system shall be provided to the Department upon request.

§ 78.65 Site Restoration

Proposed Regulation: The EQB proposes new site restoration requirements (§ 78.65) to clarify when restoration must occur and what constitutes restoration.

Comment: We support new site restoration requirements to clarify when restoration must occur and what constitutes restoration. We recommend a number of improvements to the proposed rules.

As a preliminary matter, this section confuses “restoration” with “reclamation.” Restoration is the process whereby the original structural and functional diversity of the site is reproduced as closely as possible. This process typically involves a pre-disturbance assessment of baseline conditions or the use of a reference system as a template. Reclamation, as typically practiced, is simply site stabilization in order to reduce erosion and sedimentation. The proposed EQB rules promote the more limited reclamation, rather than the restoration required to ensure that the public natural resources are not degraded. We recommend

that full restoration be required as soon as possible, and that reclamation be acceptable only as required to maintain safe operation of the well.

Clear guidelines and performance criteria are needed to define what represents site restoration or reclamation. We recommend that the proposed rule provide technical performance standards that define restoration, including type and density of perennial vegetation, soil characteristics (e.g., depth of topsoil, organic content, bulk density, pH), and drainage patterns. We have provided suggested language for these criteria below and recommend that the PADEP require documentation and approval of restoration plans that meet the defined criteria.

The standards for restoration should require full compliance with Chapter 102 (governing erosion and sediment control, stormwater management, and riparian buffers), notwithstanding the regulatory exceptions granted to oil and gas activities under § 102.8(n), until site restoration is complete and permanent. In particular, all post-construction stormwater control features identified in a site restoration plan should be supported by the stormwater analysis described in § 102.8(g).

The proposed language under § 78.65(d) would specifically allow a pad with multiple wells to be exempt from restoration until “30 calendar days after the expiration of all existing well permits on the site.” This period of time may extend for years, so it is critical that operations on site comply fully with Chapter 102, as we recommend in our comments on § 78.53, above. Proposed § 78.65(d)(2) further extends the deadline for restoration by up to two years. We oppose extension of the restoration deadline.

In § 78.65(e), no contingency or requirement has been made for long term monitoring of the integrity of the plug following decommissioning of the well. Given that the concrete plug and steel casing will eventually degrade, along with the fact that thousands of gallons of contaminated fluids remain under pressure at the base of the well, migration of these materials into the groundwater aquifer and surface water is highly probable. This eventuality will have profound ecological consequences. We recommend changes to § 78.101 to address this issue.

We also recommend removing the proposed language in § 78.65(f)(3) related to removal and restoration of pits, because we oppose their continued construction, use, and on-site burial. As is explained above, we also oppose the land application of Oil and Gas Operation waste; therefore, we recommend removing the language in § 78.65(f)(4) relating to land application of waste.

Dry holes or wells that are determined to be uneconomic should be permanently plugged and abandoned before moving the drilling equipment from the well site. Drill holes used to facilitate drilling of a well should be filled with cement.

We do not agree that written consent of the landowner should be the determining factor as to whether the operator has met the restoration requirements of § 78.65. The PADEP should solicit input from the landowner, neighboring property owners, and residents on those properties, as to whether they are satisfied with the restoration. In addition to addressing any concerns raised by the landowner, neighboring property owners, or residents, the PADEP should determine whether the regulatory requirement has been met through a record audit and on-site inspection. It is not satisfactory for the landowner to be the arbiter of the final restoration requirements, since a private contractual arrangement between the landowner and the Oil and Gas Operator may allow for restoration that is less robust than the proposed § 78.65 requirement, with adverse impacts on neighboring properties and residents. Landowners are not necessarily qualified to determine if restoration is sufficient to meet the requirements of Chapter 102, the provisions of the Clean Streams Law, or the guarantees of the Pennsylvania Constitution.

We recommend that § 78.65 be revised as follows:

§ 78.65. Site **reclamation and** restoration.

[In addition to complying with section 206 of the act (58 P. S. § 601.206), an owner or operator shall meet the following requirements:]

(a) The owner or operator shall restore the land surface within the area disturbed under section 3216 of the act (relating to well site restoration) and Chapter 102 (relating to erosion and sediment control).

[(1)] (b) A drill hole or bore hole used to facilitate the drilling of a well shall be filled with cement, **soil, uncontaminated drill cuttings or other earthen material and all dry holes or wells that are determined to be uneconomic shall be plugged and abandoned according to the requirements of §§ 78.91 through 78.98 (permanent well plugging requirements)** before moving the drilling equipment from the well site.

[(2)] (c) If a well site is constructed and the well is not drilled, the well site shall be restored **to meet the standards set forth in paragraph (e)** within 30 calendar days after the expiration of the well permit unless the Department approves an extension for reasons of adverse weather or lack of essential fuel, equipment or labor.

(d) Within 9 months after completion of drilling a well, the owner or operator shall restore the well site, remove ~~or fill all pits used to contain produced fluids or residual~~ wastes, and remove all drilling supplies, equipment, and containment systems not needed for production. When multiple wells are drilled on a single well site, post-drilling restoration is required within 9 months after completion of drilling of all permitted wells on the well site or 30 calendar days after the expiration of all existing well permits on the well site, whichever occurs later. **Notwithstanding the provisions of § 102.8(n), full compliance with § 102.8(a)-(m) shall be maintained at the well site until restoration following the plugging of all wells is complete and stable.** Drilling supplies and equipment not needed for production may only be stored on the well site if written consent of the surface landowner is obtained and, ~~for unconventional well sites,~~ the supplies or equipment are maintained in accordance with § 78.64a (relating to containment systems and practices at **unconventional Oil and Gas Operations well sites**).

(1) An area is restored under this subsection if the following are met:

(i) **Notwithstanding the provisions of § 102.8(n), a**All permanent post-construction stormwater control features as identified in the PCSM plan or site restoration plan are in place consistent with § 102.8(a)-(m) (relating to PCSM requirements).

(ii) Remaining impervious areas are **minimized eliminated, except for areas required for safe well operations**. Impervious areas include areas where the soil has been compacted, areas where the soil has been treated with amendments to firm or harden the soil and areas where soil is underlain with an impermeable liner.

(iii) All areas of the site not needed to safely operate the well are restored to **the standards set forth in paragraph (e)**~~approximate original conditions, including preconstruction contours, and can support the land uses that existed prior to oil and gas activities to the extent practicable~~. The areas needed to safely operate the well include ~~to~~ the following:

- (A) Areas used for service vehicle, **well workover equipment**, and rig access.
- (B) Areas used for storage tanks and secondary containment facilities.
- (C) Areas used for wellheads and appurtenant processing facilities.

(D) Area used for any necessary safety buffer limited to the area surrounding equipment that is physically cordoned off to protect the facilities.

(E) Area used to store ~~any~~ supplies or equipment required for exploration or production operation consented to by the surface landowner.

(F) Area used for operation and maintenance of long-term PCSM best management practices.

(iv) Notwithstanding the provisions of § 102.8(n), eEarth disturbance associated with oil and gas activities that are not included in an approved site restoration plan, and other remaining impervious surfaces, must comply with all post-construction stormwater management requirements in Chapter 102, including § 102.8(a)-(m).

(v) The site is permanently stabilized according to § 102.22(a) (relating to site stabilization).

~~—(2) The restoration period in this subsection may be extended by the Department for an additional period of time, not to exceed 2 years, upon demonstration by the well owner or operator of either of the following:~~

~~—(i) The extension will result in less earth disturbance, increased water reuse or more efficient development of the resources.~~

~~—(ii) Site restoration cannot be achieved due to adverse weather conditions or a lack of essential fuel, equipment or labor.~~

~~—(3) The demonstration under paragraph (2) shall be submitted on forms provided by the Department 6 months after the completion of drilling for approval by the Department. The demonstration must include a site restoration plan that must provide for:~~

~~—(i) The timely removal or fill of all pits used to contain produced fluids or residual wastes.~~

~~—(ii) The removal of all drilling supplies and equipment not needed for production, including containment systems.~~

~~—(iii) The stabilization of the well site that includes interim post-construction storm water management best management practices in compliance with § 102.8, including § 102.8(a)-(m).~~

~~—(iv) Other measures to be employed to minimize accelerated erosion and sedimentation in accordance with The Clean Streams Law (35 P. S. §§ 691.1—691.1001).~~

~~—(v) A minimum uniform 70% perennial vegetative cover over the disturbed area, with a density capable of resisting accelerated erosion and sedimentation, or a best management practice which permanently minimizes accelerated erosion and sedimentation.~~

~~—(vi) The return of the portions of the site not occupied by production facilities or equipment to approximate original conditions, including preconstruction contours, and supporting the land uses that existed prior to oil and gas activities to the extent practicable.~~

(42) Written consent of the landowner on forms provided by The Department shall verify that satisfies the restoration requirements of this section are met provided the operator develops and implements a site restoration plan that complies with paragraph (3)(i)-(v) and all PCSM requirements in Chapter 102 by conducting a site inspection, completing a record audit, and by ensuring that concerns of the landowner, and nearby property owners, and residents on those properties concerns are addressed. The Department shall issue a summary report with its findings within 30 days of receiving notice from the operator that the site has been restored. The Department's report shall be made available to the public on the Department's website.

(e) Within 9 months after plugging a well, the owner or operator shall remove all production or storage facilities, supplies and equipment and, to the extent technically feasible, completely and permanently restore the well site to ~~approximate~~ original conditions, including pre-construction contours, drainage patterns, type and density of native plant community, soil characteristics, and pre-development habitat features and conditions. The operator shall bear the burden of proving that complete and permanent restoration in compliance with paragraphs (1)-(5) is not technically feasible. Restoration must support the land uses that existed prior to oil and gas activities.

(1) Restoration of pre-construction contours requires restoration of individual topographic contour lines to within 1 foot of the original contour, based on original topographic conditions for areas to be disturbed. Existing topographic conditions must be documented at contours not less than 2 feet in interval.

(2) Restoration of drainage patterns requires that there be no change in drainage area to a point of discharge to a stream (as defined at § 78.1), waterbody, wetland, or spring.

(3) Restoration of the native plant community requires restoration of the type and density of native vegetation that existed at the site prior disturbance by Oil and Gas Operations. Restoration of non-native plant species shall not include plants classified as invasive or noxious vegetation. Restored vegetation must be maintained and monitored for a period of two years in order to assure plant establishment. Plants classified as invasive and/or noxious vegetation shall not exceed 5% of the site cover at the end of each growing season during the two-year maintenance period.

(4) Restoration of soil characteristics requires restoration of the depth of topsoil, organic content, bulk density, pH, and soil particle gradation that existed prior to site disturbance. The surface and sub-grade soil conditions must not be compacted to greater than 85% density.

(5) Restoration of habitat requires the restoration of conditions necessary to support the number and type of plant and animal organisms that existed prior to disturbance by Oil and Gas Operations.

~~and supporting the land uses that existed prior to oil and gas activities to the extent practicable.~~

[(3)] (f) Within 60 calendar days after the restoration of the well site, the operator shall submit a well site restoration report to the Department. The report shall be made on forms provided by the Department and shall identify the following:

~~—[(i)] (1) The date of land application of the topsoil, the results of pH and specific conductance tests and an estimated volume of discharge.~~

~~[(ii)] (2)~~ A description of the method used for disposal or reuse of the free liquid fraction of the waste, and the name of the hauler and disposal facility, if any.

~~—[(iii)] (3) The location, including GPS coordinates, of the pit in relation to the well, the depth of the pit, the type and thickness of the material used for the pit subbase, the type and thickness of the pit liner, the type and nature of the waste, the type of any approved solidifier, a description of the pit closure procedures used and the pit dimensions.~~

~~—[(iv)] (4) The location of the area used for land application of the waste, and the results of a chemical analysis of the waste soil mixture if requested by the Department.~~

[(v)] (25) The types and volumes of waste produced, ~~and~~ the name and address of the waste disposal facility and waste hauler used to dispose of the waste, and copies of all manifests documenting the disposition of the waste.

~~—(6) The name, qualifications and basis for determination that the bottom of a pit used for encapsulation is at least 20 inches above the seasonal high groundwater table.~~

~~—(7) The test results required under §§ 78.62 and 78.63 (relating to disposal of residual waste—pits; and disposal of residual waste—land application) for all unconventional wells or any conventional wells with a horizontal well bore.~~

~~—(g) The well operator shall forward a copy of the well site restoration report to the surface landowner if the well operator disposes of drill cuttings or residual waste at the well site.~~

(g) The Department shall verify that final restoration requirements of this subsections §§ 78.65(e) through 78.65(f) are met by conducting a site inspection, completing a record audit, and by ensuring concerns of the landowner, nearby property owners, and residents on those properties the landowner, and nearby property owners concerns are addressed. The Department shall issue a summary report with its findings within 30 days of receiving notice from the operator that the site has been restored. The Department's finding report shall be made available to the public on the Department's website.

§ 78.66 Reporting and Remediating Releases

Proposed Regulation: The EQB proposes to strengthen reporting and remediation requirements at § 78.66 for oil and gas well sites and access roads.

Comment: We support the proposal to strengthen reporting and remediation requirements at oil and gas well sites and access roads. Additionally, we recommend that this regulation be expanded to cover more than oil and gas well sites and access roads. Spills anywhere within the full footprint and area used by Oil and Gas Operations as defined in § 78.1 should be required to meet the improved reporting and remediation requirements.

The type and amount of material spilled or released, initial source control and containment actions, and the amount of material recovered should be reported. Spills or releases to land and air, in addition to the waters of Pennsylvania, should be reported. The PADEP should provide the reported information to the public on its website.

In addition to the list of actions proposed, the operator should be required to take action to prevent and immediately respond to fire, explosion, or other imminent hazards and dangers to human health, crops, or nearby wildlife.

We oppose the recommendation to treat contaminated wash water, waste solutions and residues generated from washing or decontaminating equipment used for spill remediation as residual waste, because those wastes contain the spilled material, albeit at a lower concentration. The EQB has proposed to allow residual waste to be disposed of in pits at the well site (§ 78.62), or by land application (§ 78.63). It is inconsistent to require an operator to clean up a spill because of the risks of contamination, and then allow recovered materials or fluids contaminated with recovered materials to be re-categorized as “residual waste,” which can be re-applied back on the land and pose a risk of contamination. All recovered spilled, or released material, and all fluids contaminated with spilled or released materials, should be collected and transported to an approved waste handling facility appropriate for treating and disposing of the spilled material.

We do not agree that the operator should be given ½ a year (180 days) to complete a site characterization to determine the extent and magnitude of the contamination and submit a site characterization report to

the appropriate PADEP regional office. Site characterization work should receive high priority, and should be done within 30 days. This work is needed to guide immediate clean-up and remediation efforts.

The proposed regulation at § 78.66(c)(3)(iii) would require the operator or responsible party to provide a report containing the site characterization and a description of any “interim remedial actions.” The proposed regulation at § 78.66(c)(3)(iv) would consider the report submitted as a “final remedial action” report if the “interim remedial actions” meet a certain standard. We recommend that § 78.66(c)(3)(iii) be clarified to require the operator to submit a report describing its “interim remedial actions” and explaining whether those actions met the clean-up standard, or whether additional remediation is required. If the site characterization indicates that the interim remedial actions taken did not adequately remediate the release, the operator or responsible party should develop and submit a remedial action plan. Remedial action plans should contain the elements outlined in § 245.311(a) (relating to remedial action plan). The report should be reviewed by the PADEP and either be deemed complete and satisfactory, or the PADEP should require additional site characterization or remediation work to be performed.

An Incident Command should be formed to contain, control and clean up the spills or releases of significance. Incident Command System (ICS) forms or reports completed as part of the response action should be made available to the public.

The PADEP should require that the operator submit a lessons learned report that summarizes its plans, actions, equipment, or procedural changes to prevent or minimize the risk of future releases.

We recommend that the proposed spill threshold of 5 gallons be revised to require immediate reporting of all spills to water regardless of volume. The PADEP’s regulations at § 91.33 require immediate reporting to PADEP of all spills to water and notification of downstream users that could be adversely affected. Alaska,⁶⁷ South Dakota,⁶⁸ North Dakota⁶⁹ and New York⁷⁰ also require reporting of spills to water as soon as the person has knowledge of the discharge.

We recommend immediate reporting of hazardous substances that meet the reportable quantities of 40 CFR § 302.4 and § 302.5, and immediate reporting of all spills greater than one gallon to land followed by a monthly report documenting spills to land of all sizes.

The EQB proposes to allow spills of less than 42 gallons to land to be cleaned up by removing the impacted soils and submitting a report to the PADEP documenting that the soil contamination has been reduced to below the § 250.707(b)(1)(iii)(B) thresholds. As proposed, the operator would not be subject to the full remediation and reporting requirements of Chapter 250. We do not support streamlined remediation requirements for spills less than 42 gallons, because some spills in small quantities can pose a significant environmental risk. For example, a 41-gallon spill of hazardous substances that meet the reportable quantities of 40 CFR §§ 302.4 and 302.5 should be required to meet the full remediation and reporting requirements of Chapter 250.

The PADEP regulations in Chapter 245 include specific remediation requirements for releases from storage tanks and associated facilities; those requirements should apply to oil and gas tanks.

⁶⁷ Alaska Dep’t of Env’tl. Conserv., *Spill Reporting Requirements*, <http://dec.alaska.gov/spar/spillreport.htm#requirements>.

⁶⁸ S.D. Dep’t of Env’t and Natural Res., *Spill Reporting Requirements*, <http://denr.sd.gov/des/gw/Spills/Spills.aspx>.

⁶⁹ N.D. Dep’t of Health, *Spill Reporting Requirements*, <https://www.ndhealth.gov/WQ/GW/spills.htm>.

⁷⁰ NYSDEC, *Spill Guidance Manual*, Section 1.1 Spill Reporting and Initial Notification Requirements, <http://www.dec.ny.gov/regulations/2634.html>.

We recommend that the PADEP take a consistent and transparent approach to remediation, and require all spills to meet the Chapter 250 requirements. The remediation method should be approved by the PADEP, and confirmation of the remediation be submitted and made available to the public via the PADEP's website. Preferably, the PADEP should consolidate the remediation reports into a website accessible to the public by GPS location.

We recommend that § 78.66 be revised as follows:

§ 78.66. Reporting **and remediating** releases.

[(a) A release of a substance causing or threatening pollution of the waters of this Commonwealth shall comply with the reporting and corrective action requirements of § 91.33 (relating to incidents causing or threatening pollution).

(b) If a reportable release of brine on or into the ground occurs at the well site, the owner or operator shall notify the appropriate regional office of the Department as soon as practicable, but no later than 2 hours after detecting or discovering the release.

(c) The notice required under subsection (b) shall be by telephone and describe:

(1) The name, address and telephone number of the company and person reporting the incident.

(2) The date and time of the incident or when it was detected.

(3) The location and cause of the incident.

(4) The quantity of the brine released.

(5) Available information concerning the contamination of surface water, groundwater or soil.

(6) Remedial actions planned, initiated or completed.

(d) If, because of an accident, an amount of brine less than the reportable amount as described in § 78.1 (relating to definitions), spills, leaks or escapes, that incident does not have to be reported.

(e) Upon the occurrence of any release, the owner or operator shall take necessary corrective actions to:

(1) Prevent the substance from reaching the waters of this Commonwealth.

(2) Recover or remove the substance which was released.

(3) Dispose of the substance in accordance with this subchapter or as approved by the Department.]

(a) *Scope.* This section applies to reporting and remediating spills or releases of regulated substances on or adjacent to the Oil and Gas Operations defined in § 78.1, well sites, and access roads.

(b) *Reporting releases.*

(1) An operator or responsible party shall report the following spills and releases of regulated substances to the Department in accordance with paragraph (2):

(i) A spill or release of a regulated substance causing or threatening pollution of the air, land or waters of this Commonwealth.

(ii) Any spill or release to water or that may threaten water resources, or of 5 gallons or more of a regulated substance over a 24-hour period to land, and any hazardous substance that meets the

reportable quantities of 40 CFR §§ 302.4 and 302.5 that is not completely contained by a containment system.

(2) In addition to the notification requirements of § 91.33 (relating to incidents causing or threatening pollution), the operator or responsible party shall contact the appropriate regional Department office by telephone or call the Department's Statewide toll free number at (800) 541-2050 as soon as practicable, but no later than 2 hours after discovering the spill or release, **and notify the local government and water suppliers immediately thereafter. The operator must also submit a spill/release report on a form furnished by the Department to the Department through its web site within 12 hours. The spill/release report shall be immediately made available to local emergency responders and the public on the Department's website. Spill/release reports must be submitted to the Department through its web site each day thereafter until the spill/release is contained, controlled, and cleaned up. The initial spill/release report and each update submitted daily thereafter shall be immediately made available to local emergency responders and the public on the Department's website. The Department shall also make available to the public on its website any Incident Command System (ICS) Forms or Reports completed as part of the response action.**

To the extent known, the following information shall be provided:

- (i) The name of the person reporting the incident and telephone number where that person can be reached.
- (ii) The name, address and telephone number of the responsible party.
- (iii) The date and time of the incident or when it was discovered.
- (iv) The location of the incident, including directions to the site, GPS coordinates or the 911 address, if available.
- (v) A brief description of the nature of the incident and its cause, what potential impacts to public health and safety or the environment may exist, including any available information concerning the contamination of surface water, groundwater or soil.
- (vi) **The type of material.** The estimated weight or volume of each regulated substance spilled or released **and the amount contained, controlled, or recovered.**
- (vii) The nature of any injuries.
- (viii) **Source control and containment actions initiated or completed and** remedial actions planned, initiated or completed.

(3) Upon the occurrence of any spill or release, the operator or responsible party shall take necessary corrective actions to prevent:

- (i) The regulated substance from reaching the waters of the Commonwealth.
- (ii) **Fire, explosion or other imminent hazards; dangers to human health, domestic or farm animals, crops and other vegetation, or nearby wildlife; and dD**amage to property.
- (iii) Impacts to downstream users of waters of the Commonwealth.

(4) The Department may immediately approve temporary emergency storage or transportation methods necessary to prevent or mitigate harm to the public health, safety or the environment. Storage may be at the site of the incident or at a site approved by the Department.

(5) After responding to a spill or release, the operator shall decontaminate equipment used to handle the regulated substance, including storage containers, processing equipment, trucks and loaders, before returning the equipment to service. Contaminated wash water, waste solutions and

residues generated from washing or decontaminating equipment shall be managed as **residual regulated waste and be collected and transported to an approved waste handling facility appropriate for treating and disposing of the spilled or released material.**

(c) *Remediating releases.* Remediation of an area affected by a spill or release **must be completed in accordance with Act 2, Chapter 250, and the following requirements: is required. The operator or responsible party shall remediate a release in accordance with one of the following:**

~~—(1) Spills or releases to the ground of less than 42 gallons at a well that do not impact or threaten to pollute waters of the Commonwealth may be remediated by removing the soil visibly impacted by the release and properly managing the impacted soil in accordance with the Department's waste management regulations. The operator or responsible party shall notify the Department of its intent to remediate a spill or release in accordance with this paragraph at the time the report of the spill or release is made. Completion of the cleanup should be documented through the process outlined in § 250.707(b)(1)(iii)(B) (relating to statistical tests);~~

~~—(2) For spills or releases to the ground of more than 42 gallons or that impact or threaten pollution of waters of the Commonwealth, the operator or responsible person may satisfy the requirements of this subsection by demonstrating attainment of one or more of the standards established by Act 2 and Chapter 250 (relating to administration of land recycling program);~~

~~—(3) For releases of more than 42 gallons or that impact or threaten polluting waters of the Commonwealth, as an alternative to paragraph (2), the responsible party may remediate a spill or release using the Act 2 background or Statewide health standard in the following manner:~~

(i) Within 15 business days of the spill or release, the operator or responsible party shall provide an initial written report **to the Department through its web site. The spill/release report shall be immediately made available to the public on the Department's website. The 15-day report shall that** includes, to the extent that the information is available, the following:

(Ai) The regulated substance involved. **The estimated weight or volume of each regulated substance spilled or released, and the amount contained, controlled, or recovered. Source control and containment actions initiated or completed and remedial actions planned, initiated or completed.**

(Bii) The location where the spill or release occurred.

(Ciii) The environmental media affected.

(Div) Impacts and continued dangers to human health, domestic or farm animals, crops and other vegetation, or nearby wildlife. Impacts to water supplies, property, buildings or utilities. **The nature of any injuries or damage.**

(Ey) Interim remedial actions planned, initiated or completed.

(ii2) The initial report must also include a summary of the actions the operator or responsible party **has taken since the spill or release has occurred and the actions it** intends to take at the site to address the spill or release such as a schedule for site characterization, to the extent known, and the anticipated time frames within which it expects to take those actions. After the initial report, any new impacts identified or discovered during interim remedial actions or site characterization shall also be reported in writing to the Department within 15 calendar days of their discovery **to the Department through its web site. The spill/release report shall be immediately made available to the public on the Department's website.**

(iii3) Within ~~180~~ **30** calendar days of the spill or release, the operator or responsible party shall perform a site characterization to determine the extent and magnitude of the contamination and

submit a site characterization report to the appropriate Department regional office describing the findings. The report shall be provided to the Department through its web site. The report shall be immediately made available to the public on the Department's website. The report must include a description of any interim or final remedial actions taken. If the site characterization indicates that the interim remedial actions taken did not adequately remediate the release, the operator or responsible party shall develop and submit a remedial action plan. Remedial action plans should contain the elements outlined in § 245.311(a) (relating to remedial action plan). For a background standard remediation, the site characterization must contain information required under § 250.204(b)—(e) (relating to final report). For a Statewide health standard remediation, the site characterization must contain information required under § 250.312(a) (relating to final report). The report shall be reviewed by the Department and either be deemed complete and satisfactory or the Department shall require additional site characterization or remediation work to be performed.

~~(iv4) This~~ The report described in § 78.66 (c)(3) may be a final remedial action report if the interim remedial actions meets all of the requirements of an Act 2 background or Statewide health standard remediation or combination thereof and the Department has deemed the remediation to be complete and satisfactory. ~~Remediation conducted under this section may not be required to meet the notice and review provisions of these standards except as described in this section.~~

~~—(v) If the site characterization indicates that the interim remedial actions taken did not adequately remediate the release the operator or responsible party shall develop and submit a remedial action plan to the appropriate Department regional office for approval. The plan is due within 45 calendar days of submission of the site characterization to the Department. Remedial action plans should contain the elements outlined in § 245.311(a) (relating to remedial action plan).~~

~~(vi5)~~ (v5) Once the remedial action plan is implemented the responsible party shall submit a final report to the appropriate Department regional office for approval. The Department will review the final report to ensure that the remediation has met all the requirements of the background or Statewide health standard, or combination thereof, except the notice and review provisions. Relief from liability will not be available to the responsible party, property owner or person participating in the cleanup.

~~(vii6)~~ (vii6) An operator or responsible party remediating a release under this paragraph may elect to utilize Act 2 at any time.

(7) Within 30 days of the spill or release, the operator shall submit a lessons learned report that summarizes its plans, actions, equipment, or procedural changes to prevent or minimize the risk of future spills or releases, including proposed amendments to its PPC plan for Department review and approval. The report shall be provided to the Department through its web site. The report shall be immediately made available to the public on the Department's website.

§ 78.67 Borrow Pits

Proposed Regulation: The Environmental Quality Board proposes a new regulation at § 78.67 for noncoal borrow areas for oil and gas well development, including performance, registration and restoration requirements.

Comment: We support the proposed new regulation at § 78.67. However, we request the proposed regulation be strengthened by referencing the proposed site restoration standards of § 78.65, and by including a PADEP review and approval process including public review.

We recommend that the regulation clarify that waste may not be stored in, disposed of or buried in a borrow pit. We do not support a two-year extension of the borrow pit restoration requirements.

We recommend that § 78.67 be revised as follows:

§ 78.67. Borrow pits.

(a) An operator who owns or controls a borrow pit that does not require a permit under the Noncoal Surface Mining Conservation and Reclamation Act (52 P. S. §§ 3301—3326), under the exemption in section 3273.1(b) of the act (relating to relationship to solid waste and surface mining), shall operate, maintain and reclaim the borrow pit in accordance with the performance standards in Chapter 77, Subchapter I and Chapter 102 (relating to environmental protection performance standards; and erosion and sediment control), and other applicable laws. **Waste shall not be stored in, disposed of or buried in a borrow pit.**

(b) Operators shall register the location of their existing borrow pits by _____, (*Editor's Note: The blank refers to 60 calendar days after the effective date of adoption of this proposed rulemaking.*) by providing the Department, in writing, with the GPS coordinates, township and county where the borrow pit is located. The operator shall ~~register the location~~ **submit an application for the use** of a new borrow pit **to the Department for review and approval** prior to construction. **The application shall be submitted electronically to the Department through its web site. The permit application shall be immediately made available to the public on the Department's website. The Department shall provide a 30-day public comment period on the proposed permit application. After considering comment received, the Department shall issue a decision on the permit.**

(c) Borrow pits used for the development of **Oil and Gas Operations** ~~oil and gas well sites and access roads~~ that no longer meet the conditions under section 3273.1 of the act must meet one of the following:

(1) Be restored within 9 months after completion of drilling all permitted wells on the well site or 30 calendar days after the expiration of all existing well permits on the well site **if the borrow pit is to be continually utilized for all permitted wells**, whichever occurs later, **to the site restoration standards of § 78.65.**

(2) Obtain a noncoal surface mining permit for its continued use **after the completion of drilling all permitted wells**, unless relevant exemptions apply under the Noncoal Surface Mining Conservation and Reclamation Act and regulations promulgated thereunder. ~~A 2-year extension of the restoration requirement may be approved under § 78.65(d) (relating to site restoration).~~

§ 78.68 Oil & Gas Gathering lines

Proposed Regulation: The EQB proposes a new regulation at § 78.68 for oil and gas gathering line construction disturbance, installation, and corrosion control requirements.

Comment: We support new requirements for oil and gas gathering lines.

Gathering lines (also referred to as “flowlines”) are more likely to corrode than “transportation pipelines” because they may contain oil, gas, and water produced along with the oil and gas (“produced water”). Gathering lines are more likely to erode because they may operate at high pressure and high throughput velocity and contain abrasive materials such as sand and sediment that is produced from the well.

We have a number of recommendations to strengthen the proposed regulations.

The EQB proposes to require all “buried” metallic “gathering lines” to meet the requirements of 49 CFR Part 192 (gas transportation pipelines) or 195 (liquid transportation pipelines). The proposed regulation at § 78.68 (h) reads:

(h) All buried metallic gathering lines shall be installed and placed in operation in accordance with 49 CFR Part 192 or 195 (relating to transportation of natural and other gas by pipeline: minimum Federal safety standards; and transportation of hazardous liquids by pipeline).

The EQB defines a “gathering pipeline” (§ 78.1) as a pipeline that gathers oil, liquid hydrocarbons, or gas *prior* to delivery to an intrastate or interstate transmission pipeline:

***Gathering pipeline*—A pipeline that transports oil, liquid hydrocarbons or natural gas from individual wells to an intrastate or interstate transmission pipeline.**

The defined term “gathering pipeline” should be used in § 78.68 instead of the undefined term “gathering line.”

The proposed rule would benefit from further clarification. First, § 78.68 appears to require application of federal standards governing *transmission* lines to *gathering* pipelines ordinarily excluded from federal requirements. We request that the EQB clarify that it intends to extend the federal standards to gathering lines built in Pennsylvania, which we agree is appropriate. Second, § 78.68 appears to require application of federal standards to rural pipelines ordinarily excluded from federal requirements, which would bring many pipelines in Pennsylvania under regulation. We request that the EQB clarify that it plans to extend federal standards to rural pipelines, which we agree is appropriate. Third, the EQB proposes to regulate only “buried metallic gathering lines,” which would exclude regulation of aboveground gathering pipelines. Both aboveground and buried gathering pipelines warrant regulation.

The proposed regulation would direct the operator of a buried metallic gathering line to the federal regulations at 49 CFR Part 192 or 195. The operator would review those regulations and determine that many, if not most, onshore and rural gathering lines in Pennsylvania are exempt from federal standards governing the transportation of gas and hazardous liquids. The outcome would be that many, if not most, gathering pipelines in Pennsylvania would not meet those standards.

If it was the EQB’s intent to require all gathering pipelines, as defined in § 78.1 of this proposed rulemaking, to meet the standards applicable to “regulated onshore gathering lines” or “regulated rural gathering lines” under 49 CFR Part 192 or 195, respectively, then this requirement needs to be made clear in the proposed regulatory language.

The operator should be reminded to comply with all applicable provisions of Chapters 102 and 105 and should obtain any required approvals prior to commencing gathering pipeline construction. The operator also should be reminded that, under 25 Pa. Code §§ 105.1, 105.14(b), 105.15, and 105.18a(a)(1), no construction activity, including temporary construction of pipelines, may adversely impact exceptional value wetlands.

We recommend that the operator be required to provide the PADEP with a final as-built construction drawing and Geographic Information System (GIS) map file of the gathering pipeline route to incorporate into the Pennsylvania state pipeline database and mapping system and make the pipeline information available to the public on the PADEP’s website.

We recommend that the proposed regulations be made clear that they will apply to both existing pipelines and new pipelines. New pipelines should be co-located with existing or proposed roads, trails or pipelines whenever possible.⁷¹

Regarding topsoil used for gathering lines, we do not support the import or export of topsoil because it can mix soil fauna species. Best practice is to create an engineered organic soil layer following the PADEP's Stormwater Best Management Practices Manual (363-0300-002). We anticipate that this manual will be updated soon, and the new standards should apply when they are available.

We recommend that § 78.68 be revised as follows:

§ 78.68. New and Existing Oil and gas gathering pipelines.

(a) All earth disturbance activities associated with oil and gas gathering **pipe**line installations and supporting facilities are limited to the construction right-of-way, work space areas, pipe storage yards, borrow and disposal areas, access roads and other necessary areas identified on the erosion and sediment control plan.

Any person installing gathering pipelines shall comply with all applicable provisions of Chapters 102 and 105 and shall obtain any required approvals prior to commencing gathering pipeline construction.

New gathering pipelines should be co-located with existing or proposed roads, trails or pipelines whenever possible to minimize footprint.

Clearing for construction right-of-way, work space areas, pipe storage yards, borrow and disposal areas, and access roads should be limited only to those areas essential for active use to minimize footprint.

(b) Highly visible flagging, markers or signs must be used to identify the shared boundaries of the limit of disturbance, wetlands and locations of threatened or endangered species habitat prior to land clearing. The flagging, markers or signs shall be maintained throughout earth disturbance activities and restoration or PCSM activities.

(c) The operator shall maintain topsoil and subsoil during excavation under the following, unless otherwise authorized by the Department:

(1) Topsoil and subsoil must remain segregated **on site** until restoration. **Topsoil may not be exported from a site.**

(2) Topsoil and subsoil must be prevented from entering watercourses and bodies of water.

(3) The soil horizons of topsoil, subsoil, and existing vegetation must be retained intact as fully as possible until replaced for restoration.

~~(4)~~ Topsoil cannot be used as bedding for pipelines.

~~(5)~~ Native topsoil **or imported engineered topsoil** must be of equal or greater quality to ensure the land is capable of supporting the uses that existed prior to earth disturbance. **Engineered soil shall meet the latest requirements of the Department's Stormwater Best Management Practices Manual (363-0300-002).**

⁷¹ Ohio Dep't of Natural Resources, *BMP's and Recommendations for Oil and Gas Activities on State of Ohio Lands, Version R2.0* (Jan. 30, 2012).

(d) Backfilling of the gathering **pipeline** trench shall be conducted in a manner that minimizes soil compaction to ensure that water infiltration rates of the soil have not been decreased.

(e) Equipment may not be refueled within the jurisdictional floodway of any watercourse or within 50 feet of any body of water.

(f) Material staging areas shall be outside of a jurisdictional floodway of any watercourse or greater than 50 feet from any body of water.

(g) The gathering **pipe**line operator shall maintain the pipeline right-of-way, service roads and points of access to minimize the potential for accelerated erosion and sedimentation and **soil compaction and** to manage post-construction stormwater and minimize impacts to existing riparian buffers in accordance with Chapter 102.

(h) All **buried new and existing** metallic gathering **pipelines used to transport gas or hazardous liquids (including crude oil, condensates, natural gas liquids, and associated produced water) between the well head and transmission line** shall be installed and placed in operation in accordance with ~~all~~ **the requirements of** 49 CFR Part 192 or 195 (relating to transportation of natural and other gas by pipeline: minimum Federal safety standards; and transportation of hazardous liquids by pipeline) **applicable, respectively, to Type B regulated onshore gathering lines or Category 3 low-stress pipelines in rural areas.**

(i) For all new gathering pipelines installed after _____ (date these regulations are approved), the operator shall provide final as-built construction drawings and a Geographic Information System (GIS) map file of the gathering pipeline route to the Department within 30 days of completing gathering pipeline construction. For all existing gathering pipelines installed prior to _____ (date these regulations are approved), the operator shall provide final as-built construction drawings and a GIS map file of the gathering pipeline route to the Department within 60 days. The Department shall incorporate the new and existing gathering pipelines into the Pennsylvania state pipeline database and mapping system and make the pipeline route information available to the public on the Department's website.

(j) All new buried gathering pipelines on slopes greater than 5% or traversing areas of shallow seasonal groundwater shall be constructed with impermeable waterstops at intervals of not less than 200 feet to prevent the unintended lateral movement of surface and shallow groundwater. Waterstops must extend for the horizontal width and vertical depth of the bottom of the pipe excavation below the pipe, and to a height of 1 foot below final surface grades.

§ 78.68a Horizontal Directional Drilling for Oil and Gas Pipelines

Proposed Regulation: The EQB proposes § 78.68a, governing horizontal directional drilling associated with gathering and transmission pipelines, including new planning, notification, construction, and monitoring requirements.

Comment: We support the requirements for horizontal directional drilling associated with gathering and transmission pipelines. We support the required authorization by the PADEP under Chapters 102 and 105 (relating to erosion and sediment control; and dam safety and waterway management) for horizontal drilling. We recommend the use of directional drilling under all watercourses, unless the PADEP determines that a dry crossing presents less risk to waters of the Commonwealth.

We recommend that the EQB make clear that horizontal directional drilling for oil and gas pipelines includes all non-vertical drilling required to install a pipeline below grade, even if some sections of hole

may not be strictly horizontal (drilled exactly 90 degrees to a vertical plane).

We recommend that drilling additives be limited to non-toxic materials, since there is a potential risk to the environment of exposure to these additives. We also recommend changes to the PPC Plan requirement similar to those we recommended for § 78.55, above. In addition to the PADEP, the operator should notify the landowner, neighboring owners, local resident, the local government and local emergency response resources relied on in the PPC at least 24 hours prior to beginning of any directional drilling activities.

We support the proposal for the monitoring of drilling fluid and pressure losses at the directional drilling operations to prevent waterbody contamination. We recommend, however, that the regulation governing drilling fluid discharge or loss of circulation be expanded to include immediate action by the directional drilling operator to shut down the drilling operations, notify the PADEP and immediately implement the PPC plan.

The proposed language of § 78.68a(i) should be revised to clarify that an emergency permit shall be requested under § 105.64 following a drilling fluid discharge or loss of drilling fluid circulation, to allow immediate remedial action necessary to alleviate an imminent threat to life, property or the environment.

We are concerned about the proposal to allow material staging areas within 50 feet of a water body. We recommend that material staging areas be located at least 100 feet away from a water body to provide a protective buffer.

We recommend that § 78.68a be revised as follows:

§ 78.68a. Horizontal directional drilling for oil and gas pipelines.

(a) Any horizontal directional drilling associated with pipeline construction related to oil and gas operations, including gathering and transmission pipelines, that occurs beneath any body of water or watercourse will be authorized by the Department in accordance with Chapters 102 and 105 (relating to erosion and sediment control; and dam safety and waterway management). **Horizontal directional drilling shall be used for crossing all bodies of water or watercourses, unless the operator demonstrates that a dry crossing presents less risk to waters of the Commonwealth. Horizontal directional drilling for oil and gas pipelines includes all non-vertical drilling required to install a pipeline below grade, even if some sections of the hole are not precisely 90 degrees to the vertical plane.**

(b) Prior to beginning of any horizontal directional drilling activity, the directional drilling operator shall develop a PPC plan under § 102.5(l) (relating to permit requirements). The PPC plan must include a site specific contingency plan that describes the measures to be taken to control, contain and collect any discharge of drilling fluids and minimize impacts to waters of the Commonwealth.

The PPC plan shall include information to demonstrate that the Oil and Gas Operator has sufficient equipment and trained and qualified personnel immediately available, or on contract, to contain, control and clean-up the worst-case discharge or respond to the worst-case emergency.

If local emergency response resources are relied on in the PPC plan, the operator must demonstrate that the local responders are trained, qualified, and equipped to respond to an industrial accident. If the local responders are not trained, qualified, and equipped to respond to an industrial accident, the operator should be required to provide its own industrial response equipment and personnel.

The operator must conduct a drill to test the PPC plan prior to commencing directional drilling, and must provide 3 days' notice of the test to the Department and local emergency response resources relied on in the PPC Plan, to provide them with the opportunity to participate.

The operator shall submit the PPC plan to the Department for review and approval as part of the permit application. Operations may not commence until Department approval of the PPC plan is complete.

Proposed revisions to the PPC plan must be submitted to the Department for review and approval prior to implementing a change to the practices identified in the PPC plan. Once approved, the Department will audit each PPC at least once during the construction operation to verify that there is sufficient trained and qualified personnel and equipment available to carry out the plan.

The PPC plan must be present onsite during drilling operations and ~~made available to~~ **filed with** the Department ~~upon request~~.

(c) The Department, **the landowner, the local government and local emergency response resources (if relied on in the PPC plan)** shall be notified at least 24 hours prior to beginning of any horizontal directional drilling activities, including conventional boring, beneath any body of water or watercourse. Notice shall be made electronically to the Department through its web site and include the name of the municipality where the activities will occur, GPS coordinates of the entry point of the drilling operation and the date when drilling will begin.

(d) All required permits and Material Safety Data Sheets shall be on site during horizontal directional drilling operations and be made available to the Department upon request.

(e) Material staging areas shall be outside of a **regulated floodplainway**, as defined in § 105.1 (relating to definitions), of any watercourse or greater than **100 50** feet from any body of water, **whichever is greater. As is required under §§ 105.1, 105.14(b), 105.15, and 105.18a(1), no construction activity, including construction of temporary pipelines, may adversely impact exceptional value wetlands.**

(f) **Non-toxic d**Drilling fluid additives other than bentonite and water must be approved by the Department prior to use. **The use of toxic drilling fluid additives is prohibited.** All approved horizontal directional drilling fluid additives will be listed on the Department's web site.

(g) Horizontal directional drilling operations shall be monitored for pressure and loss of drilling fluid returns. Bodies of water, ~~and~~ watercourses, **and wetlands** over and adjacent to horizontal directional drilling operations shall also be monitored for any signs of drilling fluid discharges. Monitoring shall be in accordance with the PPC plan. **Directional drilling operations must cease immediately if there is a drilling fluid loss or pressure drop or there is any sign of a drilling fluid discharge into any body of water, water course, or wetland.**

(h) Horizontal directional drilling activities may not result in a discharge of drilling fluids to waters of the Commonwealth. If a discharge occurs during horizontal directional drilling activities, the drilling operator shall immediately implement the contingency plan developed under subsection (b).

(i) When a drilling fluid discharge or loss of drilling fluid circulation is discovered, the loss or discharge shall be immediately reported to the Department, and the operator shall request an emergency permit under § 105.64 (relating to emergency permits), if **immediate remedial action is necessary to alleviate an imminent threat to life, property or the environment.**

(j) Any water supply complaints received by the operator shall be reported **immediately** to the Department **by telephone and** within 24 hours through the Department's web site. **The Department shall implement the requirements of § 78.51 when responding to the complaint.**

(k) -Horizontal directional drilling fluid returns and drilling fluid discharges shall be contained, stored and recycled or disposed of in accordance with Part I, Subpart D, Article IX (relating to residual waste management).

§ 78.68b Temporary Pipelines for Oil and Gas Operations

Proposed Regulation: The EQB proposes a new regulation at § 78.68b for the installation, construction, testing, inspection, operation and removal requirements for temporary pipelines used for Oil and Gas Operations.

Comment: We support requirements for temporary pipelines used for Oil and Gas Operations.

The Delaware Riverkeeper Network previously submitted comments to the PADEP outlining its concerns about, and recommendations for, the GP8 Permit for temporary pipelines and stream crossing. Those comments are attached hereto as Appendix B for the EQB's ease of reference.

As is explained above in our comments on § 78.1 with respect to the definition of "temporary pipelines," the difference between a gathering pipeline and a temporary pipeline is that the gathering pipeline is used to transport hydrocarbons to a transmission pipeline that brings it to the market, whereas a temporary pipeline is used to construct the oil or gas well or for waste generated by drilling or stimulation of a well. Because temporary pipelines are not designed to safely transport hydrocarbons to market, and these pipelines could potentially be operating at the well site while hydrocarbons are initially produced, the definition should make it clear that temporary pipelines may not be used to transport hydrocarbons to market.

We support limits on temporary pipeline crossing of water bodies and wetlands. We recommend, however, that temporary pipelines be designed and routed to avoid water or wetland crossings, unless it is not technically feasible. Where crossings cannot be avoided, operators of temporary pipelines should be required comply with all applicable provisions of Chapters 102 and 105 and to protect wetlands.

Pipelines that fail pressure tests should be successfully retested prior to use. Pressure testing should be completed using uncontaminated freshwater.

Additional criteria should be included for inspector training and qualifications, and a list of inspection components to determine fitness for service should be added. PADEP inspection and audit requirements should be added.

We recommend that § 78.68b be revised as follows:

§ 78.68b. Temporary pipelines for oil and gas operations.

(a) Temporary pipelines must meet **applicable all** requirements in Chapters 102 and 105 (relating to erosion and sediment control; and dam safety and waterway management), **notwithstanding the provisions of § 102.8(n) and regardless of the extent of land disturbed. Use of temporary pipelines for transportation of hydrocarbons is prohibited.**

(b) Temporary pipelines that transport fluids other than fresh groundwater, surface water, water from water purveyors or **approved other** sources **of uncontaminated water approved by the Department,** shall be installed aboveground except when crossing pathways, roads or railways where the pipeline may be installed below ground surface.

(c) Temporary pipelines cannot be installed through existing stream culverts, storm drain pipes or under bridges without approval by the Department under § 105.151 (relating to permit applications for construction or modification of culverts and bridges).

(d) **Temporary pipelines shall be designed and routed to avoid crossings of bodies of water, watercourses, or wetlands, unless the Oil and Gas Operator demonstrates to the Department that it is not technically feasible to route the pipeline around the body of water, watercourse, or wetland. If a temporary pipeline must cross a body of water, watercourse, or wetland, the following requirements must be met:**

(1) The section of a temporary pipeline crossing over a watercourse or body of water, ~~except wetlands,~~ may not have joints or couplings.

(2) Temporary pipeline crossings over wetlands must utilize a single section of pipe ~~to the extent practicable unless the Oil and Gas Operator demonstrates to the Department that it is not technically feasible.~~

(3) Shut off valves shall be installed on both sides of the water or wetland temporary crossing.

(4) The temporary pipeline shall be properly supported along the span to mitigate pipeline sagging and bending stresses.

(e) In addition to the requirements of subsection (c), temporary pipelines used to transport fluids other than fresh ground water, surface water, water from water purveyors or **approved** sources **of uncontaminated water approved by the Department**, must have shut off valves, check valves or other method of **segmenting immediately isolating the pipeline flow**. The control valves shall be placed at designated intervals, to be determined by the pipeline diameter, that prevent the discharge of no more than 1,000 barrels of fluid. Elevation changes that would effectively **limit stop** flow in the event of a pipeline leak shall be taken into consideration when determining the placement of shut off valves and be considered effective flow barriers.

(f) Highly visible flagging shall be placed at regular intervals, no greater than 75 feet, along the entire length of the temporary pipeline.

(g) Temporary pipelines shall be pressure tested prior to being first placed into service and after the pipeline is moved or altered. A passing test is holding 125% of the anticipated maximum pressure for 2 hours. Leaks or other defects discovered during pressure testing shall be repaired **and the pipeline shall be retested. Every temporary pipeline shall pass pressure testing** prior to use or re-use.

(h) Water used for hydrostatic pressure testing **of the temporary pipeline must be uncontaminated freshwater. If the pipeline is new and uncontaminated, the test water may be returned to its original source, as long as it remained uncontaminated during the testing. If the pipeline has been previously used, the test water must be collected and transported to an approved treatment and disposal facility. ~~shall be discharged in a manner that does not result in a discharge to waters of the Commonwealth unless approved by the Department.~~**

(i) Temporary pipelines shall be inspected **by a trained and qualified inspector to determine fitness for service** prior to and during each use.

(1) The inspector shall examine the temporary pipeline for leaks, cracks, bending stress, corrosion, erosion, material incompatibility, weld failure, joint failure, valve failure, and other forms of deterioration or physical damage, and to and verify that all the requirements of this section are met.

(2) The initial inspection must be completed by a piping inspector who applies the API 570 Piping Inspection Code Standard for Inspection, Repair, Alteration and Rerating of in-service

Piping Systems. The entire length of the temporary pipeline shall be inspected prior to use by the API 570 inspector. The API 570 inspector must determine, in writing, that the temporary pipeline is fit for service, and a record of that determination must be kept on file by the operator and made available to the Department upon request. Any repairs recommended by the API 570 inspector must be made prior to use.

(3) The operator must inspect and monitor the temporary pipeline during use and must immediately shut down the pipeline if leaks or other integrity deficiencies are identified. The temporary pipeline must be repaired, re-inspected, and found to satisfy the API 570 standard prior to use.

(4) Inspection dates and any defects and repairs to the temporary pipeline shall be documented and made available to the Department upon request.

(j) Temporary pipelines not in use for more than 7 calendar days shall be emptied and depressurized.

(k) Flammable materials may not be transported through a temporary pipeline.

(l) Temporary pipelines shall be removed in accordance with the required restoration timeline of the well site it serviced under § 78.65 (relating to site restoration).

(m) An operator shall keep records regarding the location of all temporary pipelines, the type of fluids transported through those pipelines, ~~and~~ the approximate period of time that the pipeline was installed, **inspections, testing and repair**. The records shall be ~~made available to~~ **filed annually with** the Department ~~upon request~~.

(n) The Department shall inspect each temporary pipeline at least once during its operating life, and shall conduct an audit of the temporary pipeline inspection, testing and repair records within 30 days of receipt.

§ 78.69 Water Management Plans

Proposed Regulation: The EQB proposes a new regulation at § 78.69 for water management plans.

Comment: We support the requirement to prepare a WMP. However, we recommend that this requirement be applied to all well operations, not just unconventional well operations (shale gas wells).

We recommend that § 78.69 be revised as follows:

§ 78.69. Water management plans (WMPs).

(a) *WMPs for ~~unconventional~~ well operators.* An ~~unconventional~~ well operator shall obtain a Department-approved WMP under section 3211(m) of the act (relating to well permits) prior to withdrawal or use of water sources for drilling or completing an ~~unconventional~~ well **(including stimulation treatments and well workovers)**.

(b) *Implementation.* The **following** requirements imposed by the Susquehanna River Basin Commission ~~pertaining to~~ **shall be implemented for the Ohio River Basin, Potomac River Basin, and all other river basins without River Basin Commissions:**

- (1) Posting of signs at water withdrawal locations.
- (2) Monitoring of water withdrawals or purchases.
- (3) Reporting of withdrawal volumes, in-stream flow measurements and water source purchases.
- (4) Recordkeeping **shall be implemented in the Ohio River Basin.**

Reports required in all river basins of the Commonwealth shall be submitted electronically to the Department.

(c) *Reuse plan.* A ~~nonconventional~~ well operator submitting a WMP application shall develop a reuse plan for fluids that will be used to hydraulically fracture wells. The reuse plan shall meet or improve upon the standards required for a~~A~~ wastewater source reduction strategy in compliance with § 95.10(b) (relating to treatment requirements for new and expanding mass loadings of Total Dissolved Solids (TDS))~~will satisfy the reuse plan requirement.~~ A ~~nonconventional~~ well operator shall ~~make submit~~ the reuse plan ~~available for review by to~~ the Department, ~~upon request and the plan shall be made available to the public on the Department's web site.~~

(d) *Approval.* When applicable, the requirements of this section are presumed to be achieved for those portions of a WMP for which there is an approval from the Susquehanna River Basin Commission, the Delaware River Basin Commission or the Great Lakes Commission. This subsection does not affect the requirement in subsection (a) for a WMP approved by the Department. The Department shall adopt and incorporate the requirements imposed by any of the Commissions into its approval, and may supplement those requirements.

(e) *Expiration.* Individual water sources within a WMP are valid for 5 years.

(f) *Renewal.* A WMP renewal application shall be submitted at least 6 months prior to the expiration of the 5-year term for withdrawal or use of a water source under a WMP.

(g) *Suspension and revocation.* The Department may suspend or revoke an approved water source within a WMP for failure to comply with the WMP or for any reasons in sections 3211(m), 3252 and 3259 of the act (relating to well permits; public nuisances; and unlawful conduct).

(h) *Termination.* A WMP holder may terminate approval of any water source within an approved WMP by submitting a letter to the Department's Oil and Gas District Office requesting termination of the water source approval.

(i) *Denial.* The Department may deny approval of a WMP for any of the following reasons:

- (1) The WMP application is administratively incomplete.
- (2) The WMP will adversely affect the quantity or quality of water available to other users of the same water sources.
- (3) The WMP does not protect and maintain the designated and existing uses of the water sources.
- (4) The WMP will cause an adverse impact to water quality in the watershed as a whole.

(5) The Susquehanna River Basin Commission, the Delaware River Basin Commission, or the Great Lakes Commission has denied a water withdrawal application.

§ 78.70 Road-Spreading of Brine for Dust Control

Proposed Regulation: The EQB proposes a new regulation at § 78.70 that allows road-spreading of water produced from oil and gas wells (“production brine”) on unpaved roads for dust control from conventional wells. This means brine produced from all oil and gas wells in the state of Pennsylvania, except shale gas wells (unconventional wells), can be spread on unpaved roads. The EQB prohibits the spreading of brine from coalbed methane wells, drilling, hydraulic fracture stimulation flowback, plugging fluids, or production brines mixed with well servicing or treatment fluids.

Comment: We support prohibition of brine from coalbed methane wells, drilling, hydraulic fracture stimulation flowback, plugging fluids, or production brines mixed with well servicing or treatment fluids.

However, we believe that this prohibition should apply to all road-spreading of production brine, until the EQB provides the public with scientific data demonstrating that the production brine treatment provided by Oil and Gas Operations in Pennsylvania results in treated brine that meets both EPA's and Pennsylvania's safe drinking water standards, unless the EQB allows spreading only of treated waters that meet that standard.

We are concerned that the production brine proposed to be spread on Pennsylvania's road system may contain hydrocarbons, heavy metals, radionuclides, and other chemicals that can be harmful to humans, wildlife, and ecosystems and that it may contaminate nearby waters and soils. Oil and Gas Operations typically do not treat production brine to drinking water quality standards (as further explained below), and the amount and type of contaminants can vary widely by operator, field, and over time.

Currently the PADEP requires the operator to test any road-spreading brine for: calcium, sodium, chloride, magnesium and total dissolved solids.⁷² The operator does not have to test for hydrocarbons, heavy metals, radionuclides, and other chemicals. While the PADEP requires "free oil" to be separated from the brine before spreading, the agency does not set a limit on the amount of oil, grease or other hydrocarbon contamination that can remain in the brine. Typically, produced brine, after one to two phases of separation, including gravity separation, can still contain 5 to 10 mg/l of hydrocarbons.

The term "production brine" is not defined at § 78.1, and should be defined to clarify intent.

Production brine (more commonly called "produced water" by petroleum engineers and the oil and gas industry) means the water produced along with the oil and/or gas from the formation. It also includes water and chemicals injected into the ground to enhance hydrocarbon production (e.g., water flooding or enhanced oil recovery (EOR) operations).

Produced water (mixed with hydrocarbons and other waters or chemicals introduced into the formation during water flooding or EOR) is produced at the wellhead and then routed by pipeline to be processed at the surface. Because produced water is in direct contact with hydrocarbons in the reservoir and is mixed with hydrocarbons as it is produced through the well and into the surface processing facilities, produced water ("production brine") typically contains some amount of hydrocarbons (5-10 mg/l),⁷³ depending on the amount and type of processing that is completed prior to use. Hydrocarbons remaining in the production brine may contain VOCs such as benzene, toluene, ethyl benzene, and xylene (BTEX), which are known carcinogens. The production brine also will contain any contaminants in the water or chemicals with which it comes into contact along the pathway. Therefore, if production brine is spread on the road, residual hydrocarbon components and chemicals contained in the production brine may be released to the air, contaminate the road surface, and be washed by precipitation into streams and onto land, from which it can pollute groundwater.

In 2011, the Society of Petroleum Engineers (SPE) issued a paper describing the challenges of reusing produced water (production brine").⁷⁴ The SPE paper explains:

Produced Water and Typical Treatment. *Produced water is the aqueous liquid phase that is co-produced from a producing well along with the oil and/or gas phases during normal production operations. This includes water naturally occurring alongside*

⁷² PADEP, *Roadspreading of Brine for Dust Control and Road Stabilization, Fact Sheet*, 5500-FS-DEP1801 (rev. July 2010.)

⁷³ SPE, *Challenges in Reusing Produced Water 2* (Oct. 2011) (SPE White Paper).

⁷⁴ SPE, *Challenges in Reusing Produced Water 2* (Oct. 2011) (SPE White Paper).

hydrocarbon deposits, as well as water injected into the ground. The following are the main contaminants of concern in produced water:

- *High level of total dissolved solids (TDS)*
- *Oil and grease*
- *Suspended solids*
- *Dispersed oil*
- *Dissolved and volatile organic compounds*
- *Heavy metals*
- *Radionuclides*
- *Dissolved gases and bacteria.*
- *Chemicals (additives) used in production such as biocides, scale and corrosion inhibitors, and emulsion and reverse-emulsion breakers*

The amount of produced water, and the contaminants and their concentrations present in produced water usually vary significantly over the lifetime of a field. Early on, the water generation rate can be a very small fraction of the oil production rate, but it can increase with time to tens of times the rate of oil produced. In terms of composition, the changes are complex and site-specific because they are a function of the geological formation, the oil and water (both in-situ and injected) chemistry, rock/fluid interactions, the type of production, and required additives for oil-production-related activities.

SPE further explains that to remove the main contaminants in produced water, many of the same methods used for drinking water treatment must be employed. Yet, most oil and gas processing plants do not include this level of treatment for produced water, unless required by regulation. SPE described treatment needs and alternatives:

Treatment Alternatives

Considering the main contaminants present in produced water, treatment goals include deoiling, desalination, degassing, suspended solids removal, organic compounds removal, heavy metal and radionuclides removal, and disinfection. These treatment goals are essentially the same for potable, nonpotable reuse, or disposal, although the level of contaminant removal required for potable reuse can be significantly higher, depending on the quality of the produced water.

The SPE paper lists the type of produced water treatment options available (e.g., aeration, settling, sand filtration, ion exchange, reverse osmosis, coagulation, flocculation, filtration, etc.) describing treatment methods that are not typically used at Oil and Gas Operations and would have to be added to treat the water prior to road spreading. Alternatively, the produced water would need to be transported to a facility that could provide this treatment.

Ohio has tested production brine at various locations over a period of many years.⁷⁵ Ohio's testing found metals, including heavy metals, in the production brine. Table 4 from the Ohio report shows that metal content in Ohio production brine exceed EPA's maximum contaminant level for drinking water for several metals, including barium, cadmium, chromium, lead and nickel. While Ohio notes in their report that production brine, once applied to the road may be diluted further, there is no guarantee of the timing

⁷⁵ Oh. Dep't of Natural Res., Div. of Mineral Res. Mgt., *Spreading Oil-Field Brine for Dusts and Ice Control in Ohio, A Guidance for Local Authorities* 20 (rev. Sept. 2004)

or magnitude of that dilution process. Dilution is not guaranteed or a reliably effective way to avoid contaminant accumulation above acceptable drinking water levels.

Trace Element	Range in Ohio Brines	Maximum Contaminant Level for Drinking Water
Barium	0.1 to 255 (mg/l)	2 mg/l
Zinc	0.05 to 4.1 (mg/l)	
Cadmium	0.4 to 181 (ug/l)	5 ug/l
Chromium	0.6 to 644 (ug/l)	100 ug/l
Cobalt	0.4 to 155 (ug/l)	
Copper	0.3 to 220 (ug/l)	1300 ug/l
Lead	5 to 1300 (ug/l)	50 ug/l
Mercury	0.70 to 0.915 (ug/l)	2 ug/l
Molybdenum	4 to 51 (ug/l)	
Nickel	0.7 to 637 (ug/l)	100 mg/l
Vanadium	0.6 to 30 (ug/l)	

The PADEP has not addressed well-founded environmental and health concerns with the road-spreading of production brine. The PADEP also has not issued—subject to impact analysis and public review—a specific “beneficial use” permit for the practice. This process should not be circumvented by allowing road-spreading in the proposed regulations.

We therefore recommend that § 78.70 be deleted in its entirety.

§ 78.70a Pre-Wetting, Anti-icing, and De-icing

Proposed Regulation: The EQB proposes a new regulation at § 78.70a for spreading of water produced from oil and gas wells (“production brine”) for pre-wetting, anti-icing, and de-icing purposes on paved road surfaces. The proposed regulation includes limitations on the type of wells that the brine can come from and requires an approved plan. The EQB Board proposes to allow only “production brine” from conventional wells to be used.

Comment: We support prohibition of brine from coalbed methane wells, drilling, hydraulic fracture stimulation flowback, plugging fluids, or production brines mixed with well servicing or treatment fluids. However, we believe that this prohibition should apply to all production brine. Because salinity loads must be kept elevated in order for production brine to function as an effective de-icer, the practice will push salinity loads far above natural conditions—making the practice inherently damaging to water quality and vegetation, particularly in areas already under stress from pollution.

While the proposed regulation at § 78.70a (for paved roads) is an improvement over the proposed regulation at § 78.70 (for unpaved roads), because it includes more specific limitations on the maximum contaminant levels allowed and the required tests that must be performed on the brine, the same environmental and health concerns apply here. We remain concerned the required sampling does not examine for the full suite of contaminants that may be contained in the brine and that the PADEP has not subjected the practice to the public review required for a beneficial use permit. For more detail, please see our comments on § 78.70.

We therefore recommend that § 78.70a be deleted in its entirety.

§ 78.72 Use of Safety Devices – Blowout Prevention Equipment

Proposed Regulation: The EQB proposes a very minor update to the blowout prevention equipment regulation at § 78.72 to change a Chapter 78 reference number.

Comment: We recommend that the blowout prevention equipment regulation at § 78.72 be revised more substantially to improve safe well control practices.⁷⁶ The improvements are necessary to address problems such as that seen in 2010, when Pennsylvania suspended EOG Resources Inc.'s drilling activities at the Punxsutawney Hunting Club after a 16-hour well blowout caused by a failed blowout preventer.⁷⁷

All oil and gas wells should have a blowout preventer installed after the surface casing seat is set.⁷⁸ Diverter systems should be installed and used prior to the blowout preventer installation.⁷⁹ Design, pressure rating, installation, testing, and maintenance requirements should be improved to meet best technology and operating practice standards, such as those required in the states of Alaska,⁸⁰

⁷⁶ Most states currently require a blowout preventer to be designed to handle the maximum anticipated well pressure. This approach does not provide an additional margin of safety. For example, if the maximum anticipated well pressure is 5,000 psi and the blowout preventer selected is also 5,000 psi there is no room for error. An additional margin of safety should be provided of at least 20%. Engineers commonly used safety factors of 20% or higher.

⁷⁷ *Pa. Orders Company to Halt Drilling After Well Blowout*, Philly.com, (June 8, 2010), http://articles.philly.com/2010-06-08/news/24961451_1_eog-resources-blowout-drilling-operations.

⁷⁸ Texas requires operators to install a BOP as soon as the surface casing is set. *See* Texas Admin. Code § 3.13 (a)(6)(B)(i).

⁷⁹ Alaska requires a high capacity flow diverter system on the conductor casing. *See* 20 AAC § 25.035(c).

⁸⁰ *See, e.g.*, 20 AAC §§ 25.035(e)(4) (requiring that an accumulator system 1.5 times the volume of fluid capacity necessary to close and hold closed all blow-out prevention components be installed with an automatic backup and that the system have a minimum pressure of 200 psi above the pre-charge pressure without assistance from a charging); 25.035(e)(10)(C) (requiring that any blowout preventer components that have been used for well control or the use of which may have compromised its effectiveness be function pressure-tested before use); §25.035(e)(4) (requiring locking devices and a fire wall to shield accumulators and primary controls); 25.035(e)(4) (requiring one complete set of operable remote blowout preventer controls on or near the operator's station and a second control on the drilling floor); 25.035(e)(10)(G) (requiring blowout preventer test data to be provided within 5 days of the test); 25.035(e)(10)(H) (requiring 24 hours' notification to provide the responsible agency an opportunity to witness the blowout preventer test); 25.035(e)(10)(A) and (B) (requiring testing every 7 days for exploration wells and every 14 days for other types of wells where pressure data is known).

California,⁸¹ and Texas.⁸² We also recommend the use of a blind shear ram. Blind shear rams are designed to cut drill pipe and shut in the well in an emergency well control situation, they are a critical piece of equipment in a blowout preventer. Pipe rams can close off the annulus around the drill pipe, and blind rams can close the well off if the drill pipe is not in the hole obstructing the closure of the blind ram. However, a blind shear ram is the only device that is capable of severing the drill pipe and shutting in the well if the drill pipe is located in the hole.⁸³

If the EQB believes that there should be exceptions to this requirement, and drilling should be allowed to continue below the surface casing seat of any oil or gas well in Pennsylvania without a blowout preventer, the EQB should provide technical information to support its position.

We recommend that § 78.72 be revised as follows:

§ 78.72. Use of safety devices—blow-out prevention equipment.

(a) The operator shall ~~use~~ **install and test** blow-out prevention equipment **as soon as practicable, but no later than** after setting **surface** casing with a competent casing seat and prior to drilling out of the surface casing. ~~in the following circumstances: Blowout prevention equipment shall be installed, operated, tested and maintained in accordance with API RP 53 (Recommended Practices for Blowout Prevention Equipment Systems).~~

A diverter system shall be installed on the conductor casing while drilling surface casing in geographic areas that have not yet been drilled, unless waived by the Department based on prior drilling data that confirms shallow gas and other drilling hazards are not present.

The required working pressure rating of all blowout preventers, and other well control equipment, shall be based on known or anticipated subsurface pressure, geologic conditions, and professional engineering practices and shall exceed the maximum anticipated pressure to be contained at the surface by a safety factor of at least 20%.

An accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all blow-out prevention components must be installed with an automatic backup. The system must perform with a minimum pressure of 200 psi above the pre-charge pressure without assistance from a charging. Minimum requirements for accumulator testing shall include pre-charge of accumulator bottle, accumulator response time, and the capability of closing on the minimum size drill pipe being used.

~~—(1) When drilling a well that is intended to produce natural gas from an unconventional formation.~~

~~—(2) When drilling out solid core hydraulic fracturing plugs to complete a well.~~

~~—(3) When well head pressures or natural open flows are anticipated at the well site that may result in a loss of well control.~~

⁸¹ California requires an accumulator system. See Calif. Code Regs. tit. 14, § 1722.5.

⁸² See, e.g., Texas Admin. Code §§ 3.13(a)(6)(B)(vii) (requiring that operators meet API RP 53); 3.13(a)(6)(B)(i) (requiring that operators install a diverter on the conductor casing when shallow gas is anticipated); 3.13(a)(6)(B)(vii) (requiring that operators test the blowout preventer using API RP 53 test procedures); 3.13(a)(6)(B)(vii) (requiring operators use have the blowout preventer independently certified once every 5 years).

⁸³ The federal government and states including Alaska and California require blind shear rams to be installed in offshore blowout preventers. Blind shear rams provide an additional measure of safety and should be considered for use in Pennsylvania.

~~—(4) When the operator is drilling in an area where there is no prior knowledge of the pressures or natural open flows to be encountered.~~

~~—(5) On wells regulated by the Oil and Gas Conservation Law (58 P. S. §§ 401—419).~~

~~—(6) When drilling within 200 feet of a building.~~

(b) Blow-out prevention equipment used must be in good working condition at all times. Prior to use on a well, the operator must ensure that the blow-out preventer selected is appropriate for the planned rig and well type, that the blow-out preventer or auxiliary equipment has not been compromised or damaged from previous service, and that the blow-out preventer will operate in the conditions for which it will be used. A blind shear ram must be installed and be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures.

Operational and physical barriers must be installed on the blow-out preventer control panels to prevent accidental disconnect functions. The blow-out preventer control panel system must be clearly labeled. There must be a management system for operating the blow-out preventer, including for the prevention of accidents or unplanned disconnects of the system. There must be minimum requirements for personnel authorized to operate critical blow-out preventer equipment.

~~(b)(c)~~ Controls for the blow-out preventer shall be accessible on the rig floor and allow for remote actuation of the blow-out preventer equipment in a rig evacuation. ~~Additional~~ Remote blow-out preventer controls ~~for a blow-out preventer with a pressure rating of greater than 3,000 psi, not associated with the rig hydraulic system,~~ shall be located at safe distance least 50 feet away from the drilling rig, calculated by the drilling engineer responsible for the well design, based on the maximum well blow-out trajectory distance, so that the blow-out preventer can be actuated if control of the well is lost.

(d) The operator shall use pipe fittings, valves and unions placed on or connected to the blow-out prevention systems that have a working pressure capability that exceeds the anticipated pressures by at least by a safety factor of at least 20%.

(e) The operator shall conduct a complete test of the ram type blow-out preventer and related equipment for both pressure and ram operation before placing it in service on the well. The operator shall test the annular type blow-out preventer ~~in accordance with the manufacturer's published instructions, or the instructions of a professional engineer,~~ prior to the device being placed in service. Testing shall be conducted in accordance with American Petroleum Institute publication API RP53, "API Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells." Blow-out prevention equipment that fails the test may not be used until it is repaired and passes the test.

Blowout preventer testing certification shall be obtained through an independent company that tests blowout preventers. Certification shall be performed every five (5) years and the proof of certification shall be provided to the Department within 7 days of certification.

The operator must notify the Department at least 24 hours prior to commencing any blow-out preventer testing. The operator must keep a written record of all design, installation, testing, and repairs on the blow-out preventer.

~~(e)(f)~~ When the equipment is in service, the operator shall visually inspect blow-out prevention equipment during each tour of drilling operation and during actual drilling operations test the pipe rams for closure daily and the blind rams for closure on each round trip. When more than one round trip is made in a day, one daily closure test for blind rams is sufficient. The annular-type preventer shall be tested by closing on the drill pipe at least once each week. Testing shall be conducted in accordance with American Petroleum Institute publication API RP53, "API Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells," ~~or other procedure approved by the Department.~~

The operator shall record the results of the inspection and closure test in the drillers log before the end of the tour. If blow-out prevention equipment is not in good working order, drilling shall cease when cessation of drilling can be accomplished safely **and the Department must be immediately notified. Alternative well control measures must be immediately instituted to secure the well. Drilling shall and** not resume until the blow-out prevention equipment is repaired or replaced and **successfully** retested.

(g) All lines, valves and fittings between the closing unit and the blow-out preventer stack must be flame resistant and have a rated working pressure that meets or exceeds the requirements of the blow-out preventer system **by a safety factor of at least 20%**.

(h) When a blowout preventer is installed or required under subsection (a), there shall be present on the well site an individual with a current certification from a well control course accredited by the International Association of Drilling Contractors or other organization approved by the Department. The certification shall be available for review at the well site. The Department will maintain a list of approved accrediting organizations on its web site.

(i) Well drilling and completion operations requiring pressure barriers, as identified by the operator under [**§ 78.55(b) (relating to control and disposal plan)**] **§ 78.55(d) (relating to control and disposal planning; emergency response for unconventional well sites)**, shall employ at least two mechanical pressure barriers between the open producing formation and the atmosphere that are capable of being tested. The mechanical pressure barriers shall be tested according to manufacturer specifications prior to operation. If during the course of operations the operator only has one functioning barrier, operations must cease until additional barriers are added and **successfully** tested or the redundant barrier is repaired and **successfully** tested. Stripper rubber or a stripper head may not be considered a barrier.

(j) A coiled tubing rig or a hydraulic workover unit with appropriate blowout prevention equipment must be employed during post completion cleanout operations **or during a well workover in horizontal unconventional formations.**

(k) The minimum amount of intermediate casing that is cemented to the surface to which blow-out prevention equipment may be attached, shall be in accordance with the following:

<i>Proposed Total Vertical Minimum Cemented Casing</i>	
<i>Depth (in feet)</i>	<i>Required (in feet of casing cemented)</i>
Up to 5,000	400
5,001 to 5,500	500
5,501 to 6,000	600
6,001 to 6,500	700
6,501 to 7,000	800
7,001 to 8,000	1,000
8,001 to 9,000	1,200
9,001 to 10,000	1,400
Deeper than 10,000	1,800

(l) Upon completion of the drilling operations at a well, the operator shall install and utilize equipment, such as a shut-off valve of sufficient rating to contain anticipated pressure, lubricator or similar device, as may be necessary to enable the well to be effectively shut-in while logging and servicing the well and after completion of the well.

78.73 General Provisions for Well Construction and Operation

Proposed Regulation: The EQB proposes to add requirements to the existing regulation at § 78.73 requiring orphaned/abandoned well monitoring during stimulation activities at a nearby well. The proposed regulation would require the operator to plug the orphaned/abandoned well after it confirms that the stimulation job altered the well.

Comment: As explained in our comments on proposed regulation § 78.52a (Abandoned and Orphaned Well Identification), we recommend that all improperly abandoned and orphaned wells be identified and properly P&A'd before an operator pursues site development for new wells or conducts a stimulation in a nearby well. We do not support a regulation that would intentionally risk damage to existing wells – possibly causing groundwater contamination through the migration of methane and other contaminating substances – and then require that the operator to plug the well after the damage already has been done. Furthermore, there is no proposed requirement that the operator identify whether groundwater has been contaminated or to remediate any contamination. The operator is instructed only to plug the well.

It is also unclear how the EQB is proposing to meet the standard of “visual monitoring of an orphaned or abandoned well.” Does this mean posting a staff member on watch at the surface of each orphaned or abandoned to see if the well leaks to surface during the entire stimulation process at the nearby well? Even such a measure would be insufficient, since while flow to surface would certainly be a catastrophic failure, and observation at the surface would not detect subsurface contamination that is not visually indicated aboveground. The proposed method appears to place both the public and ecosystems at unnecessary risk and to give precedence to operator convenience over environmental protection.

We also recommend that the regulation clarify the type of casing seat it references, require immediate notification to the PADEP of the potential for well failure and groundwater contamination, and the preferential use of gas for fuel.

As explained in our comments on proposed regulations §§ 78.56, 78.57 and 78.58, we recommend that systems be installed to capture air pollution and route vapors to be sold or used for power (preferably), or alternatively to an incinerator or flare. The operator should be required to examine the technical and economic feasibility of using vapors for power, and only incinerate or flare when use as power is not feasible. Direct venting should be prohibited.

Gas flaring is environmentally preferable over venting because flaring reduces HAPs, VOC emissions, and GHG emissions. When incineration or flaring is required, regulations should set an upper bound on the maximum volume of gas incinerated/flared. A minimum incinerator or flare efficiency of 98% should be required. The incinerator and flare systems should be designed in a manner that optimizes reliability, safety, and combustion efficiency. Requirements should include: minimizing the risk of pilot blowout by installing a reliable system; ensuring sufficient exit velocity or provide wind guards for low/intermittent velocity streams; ensuring use of a reliable ignition system; minimizing liquid carry over and entrainment in the gas stream by ensuring a suitable liquid separation system is in place; and maximizing combustion efficiency by proper control and optimization of fuel/air/steam flow rates.

Therefore, we recommend that § 78.73 be modified as follows:

§ 78.73. General provision for well construction and operation.

(a) The operator shall construct and operate the well in accordance with this chapter and ensure that the integrity of the well is maintained and health, safety, environment, and property are protected.

(b) The operator shall prevent gas, oil, brine, completion and servicing fluids, and any other fluids or materials from below the water protection casing string casing seat (e.g., surface casing seat or intermediate casing seat, when intermediate casing is installed for water protection) from entering fresh groundwater, and shall otherwise prevent pollution or diminution of fresh groundwater.

~~(c) Orphaned or abandoned wells identified under § 78.52a (relating to abandoned and orphaned well identification) that likely penetrate a formation intended to be stimulated shall be visually monitored during stimulation activities. The operator shall immediately notify the Department of any change to the orphaned or abandoned well being monitored and take action to prevent pollution of waters of the Commonwealth or discharges to the surface. An operator that alters an orphaned or improperly abandoned well by hydraulic fracturing shall plug the orphaned or abandoned well.~~

[(c)] ~~(ed)~~ After a well has been completed, recompleted, reconditioned or altered the operator shall prevent surface shut-in pressure and surface producing back pressure inside the surface casing or coal protective casing from exceeding the following pressure: 80% multiplied by 0.433 psi per foot multiplied by the casing length (in feet) of the applicable casing.

[(d)] ~~(fe)~~ After a well has been completed, recompleted, reconditioned or altered, if the surface shut-in pressure or surface producing back pressure exceeds the pressure as calculated in subsection [(c)] ~~(ed)~~, the operator shall immediately notify the Department and take immediate action to prevent the migration of gas and other fluids from lower formations into fresh groundwater. To meet this standard the operator may cement or install on a packer sufficient intermediate or production casing or take other actions approved by the Department. This section does not apply during testing for mechanical integrity in accordance with State or Federal requirements.

[(e)] ~~(gf)~~ Excess gas encountered during drilling, completion or stimulation shall be used for fuel, where technically feasible, and otherwise flared, captured or diverted away from the drilling rig in a manner that does not create a hazard to the public health or safety. Notwithstanding the provisions of § 78.102(3), direct venting is prohibited. The operator must examine the technical and economic feasibility of using vapors for power or sale as fuel and may incinerate or flare only when use for power or sale as fuel is not feasible. If incineration or flaring is the only feasible option, an incinerator or flare efficiency of 98% is required. The incinerator and flare systems shall be designed in a manner that optimizes reliability, safety, and combustion efficiency. Requirements include: minimizing the risk of pilot blowout by installing a reliable system; ensuring sufficient exit velocity or provide wind guards for low/intermittent velocity streams; ensuring use of a reliable ignition system; minimizing liquid carry over and entrainment in the gas stream by ensuring a suitable liquid separation system is in place; and maximizing combustion efficiency by proper control and optimization of fuel/air/steam flow rates.

[(f)] ~~(h)~~ Except for gas storage wells, the well must be equipped with a check valve to prevent backflow from the pipelines into the well.

§ 78.91 Plugging – General Provision

Proposed Regulation: The EQB did not propose revisions to the general plugging requirements at § 78.91.

Comment: We recommend that the general plugging provisions at § 78.91 be expanded to clarify both the PADEP's and the Oil and Gas Operator's obligations for permanently plugging and abandoning wells and monitoring wells for subsurface contamination and surface gas leaks until the well can be permanently plugged and abandoned to meet the PADEP plugging standards at §§ 78.91 - 78.98.

The highest risk of subsurface contamination and surface gas leaks are wells that:

- (1) Were improperly plugged and abandoned, where the procedure used did not comply with the improved, current the PADEP plugging requirements at §§ 78.91 - 78.98. This could include wells that were plugged and abandoned using older methods, or wells that were not plugged in compliance with the PADEP regulations;
- (2) Are currently inactive, and have not been plugged; and,
- (3) Are orphaned and have not been plugged.

Operating wells (§ 78.88) and inactive wells (§ 78.103) are both subject to monitoring requirements; however, improperly plugged and abandoned wells and orphan wells are not.

First, we recommend that the PADEP complete an audit of all the wells in the state, and make that audit available to the public, to verify exactly which wells are currently:

- (1) Operating wells subject the ongoing mechanical integrity monitoring requirements of § 78.88;
- (2) Inactive wells that meet the criteria of §§ 78.101 - 78.105, subject to the monitoring requirements of § 78.103;
- (3) Wells that have been previously plugged and abandoned, and the methods used meet the current PADEP plugging requirements at §§ 78.91 - 78.98, or provide equivalent or better protection;
- (4) Wells that have been previously plugged and abandoned, and do not meet the current PADEP plugging requirements at §§ 78.91 - 78.98, or do not provide equivalent or better protection; or,
- (5) Orphaned wells that have not been plugged at all.

Second, we recommend that the EQB request additional legislative funding appropriation to immediately remedy the existing back-log of unplugged orphaned wells and plug those wells to the PADEP's plugging standards at §§ 78.91 - 78.98. The PADEP's orphaned well funding is insufficient to complete this work for all wells in Pennsylvania on a timely basis.

We recognize that plugging all the orphaned wells in Pennsylvania could take a period of a few years; therefore, we recommend that the EQB also request a legislative funding appropriation to conduct surface and subsurface monitoring of the orphaned wells in the interim until they are plugged. Monitoring will aid the PADEP in identifying and prioritizing the plugging order of the wells based on the wells with the highest subsurface contamination and surface gas leak risk.

Third, for wells that have been previously plugged and abandoned, and do not meet the current PADEP plugging requirements at §§ 78.91 - 78.98, or do not provide equivalent or better protection, we recommend that the regulations require these wells to be re-entered and plugged to meet the current PADEP plugging requirements at §§ 78.91 - 78.98. During the interim, before the well is plugged to the current standard, the regulation should require surface gas monitoring for leaks on at least a quarterly basis, and annual subsurface monitoring (if the well was left in a condition where monitoring equipment re-entry is feasible).

Fourth, for all wells (even those plugged to the requirements of §§ 78.91 - 78.98), we recommend periodic monitoring for surface leaks, at least once every five years.

We recommend that four new subsections be added to § 78.91. Because all of the following text is new, we have used regular font to enhance readability.

§ 78.91. General provisions

- (i) By December 31, 2015, the Department will complete an audit of all the oil and gas wells in the state, and make that audit available to the public within 30 days of completion, to verify the status of each oil and gas well in Pennsylvania. The Department will produce a list containing the name of each well, and the status of each well. The well status for each well will fall into one of the following categories:
 - (1) An operating well subject the ongoing mechanical integrity monitoring requirements of § 78.88;
 - (2) An inactive well that meets the criteria of §§ 78.101 - 78.105, subject to the monitoring requirements of § 78.103;
 - (3) A well that has been previously plugged and abandoned that meets the current Department plugging requirements at §§ 78.91 - 78.98;
 - (4) A well that has been previously plugged and abandoned and does not meet the current Department plugging requirements at §§ 78.91 - 78.98, or does not provide equivalent or better protection; or,
 - (5) An orphaned well that has not been plugged at all.
- (j) By December 31, 2017, the Department will plug all existing orphaned oil and gas wells in Pennsylvania to meet the PADEP plugging requirements of §§ 78.91 - 78.98. During the period from ____ (Editor's note: enter effective date of regulations) to December 31, 2015, the Department will prioritize the orphaned wells risk based on the potential for subsurface or surface leaks and contamination and issue the prioritized list to the public by January 31, 2016. Surface and subsurface monitoring will be conducted by the Department at orphaned wells to assess the risk, and to continue to monitor the risk of these wells and reprioritize the plugging order, to ensure the highest risk wells are plugged first.
- (k) By January 31, 2016, the Department will notify each operator of a well that was previously plugged and abandoned, but does not meet the current Department plugging requirements at §§ 78.91 - 78.98 or provide equivalent or better protection, to re-enter the well and plug and abandon the well to meet the current Department plugging requirements at §§ 78.91 - 78.98 by no later than December 31, 2017. During the interim, before the well is re-plugged, quarterly surface gas monitoring for leaks and annual subsurface monitoring of the well must be completed must be performed by the operator, (if the well was left in a condition where monitoring equipment re-entry is feasible), and the results must be reported to the Department within 30 days of collection. The Department will require immediate plugging and abandonment of wells where monitoring data shows leakage, potential contamination, or actual contamination.
- (l) Effective ____ (Editor's note: enter effective date of regulations) each well plugged to the requirements of §§ 78.91 - 78.98, must be periodically monitored for surface leaks. Monitoring must consist of a physical on-site visit to the well to examine for any surface leaks of oil or gas, including hydrocarbon testing of any contaminated soil around the well and for gas leaks. Testing at each well must be conducted by the Oil and Gas Operator, or for orphaned wells by the Department, at least once every five years. All monitoring and testing results must be reported to the Department within

30 days of collection. The Department will require immediate action to re-enter the well and remedy any well where monitoring data indicates leakage or contamination.

§ 78.102 Criteria for Approval of Inactive Status

Proposed Regulation: The EQB did not propose any changes to § 78.102 (Criteria for approval of inactive status).

Comment: We recommend changes to the criteria for approval of inactive status.

First, we recommend that wells granted inactive status be required to meet the PADEP's current casing and cementing standards. We do not support exemptions for continued inactive operation of wells that do not meet the PADEP's casing and cementing standards (§§ 78.81—78.86). As evidenced by the PADEP's adoption of these regulations, these casing and cementing standards are critical to ensure groundwater protection and safety. Wells constructed with outdated technology and practices should be plugged and abandoned and should not be granted inactive status for a period of 5 years or longer (if renewed).

Second, we recommend that § 78.102(3) be revised to prohibit direct venting of greenhouse gases to the atmosphere. Gas should either be produced and sold or used as local fuel, or the well should be physically modified (temporarily plugged) to control the gas or permanently plugged and abandoned. We also recommend that § 78.102(4) be revised, including to require that any plan for inactive status include wellbore diagrams illustrating the current and proposed mechanical configuration and condition of the well during inactive status.⁸⁴

Third, we recommend that a petroleum engineer be required to complete a record review of the well's condition, conduct an on-site inspection, conduct a mechanical integrity test on the well, and certify that the requirements of § 78.102(1)-(4) have been met.⁸⁵ The petroleum engineer's report should include photographs of the wellhead, well pressure readings, a copy of the mechanical integrity test, and confirmation that there was not discoloration, fluid or sheen visible on the ground near the well or in any nearby water.⁸⁶

We recommend the following revisions of § 78.102:

§ 78.102. Criteria for approval of inactive status.

To obtain inactive status, the applicant shall affirmatively demonstrate to the Department's satisfaction that:

- (1) The condition of the well is sufficient to:
 - (i) Prevent damage to the producing zone or contamination of fresh water or other natural resources or surface leakage of substances.
 - (ii) Stop the vertical flow of fluid or gas within the well bore.
 - (iii) Protect fresh groundwater.

⁸⁴ Alaska requires this information to be submitted with an application to suspend a well. 20 AAC § 25.110.

⁸⁵ New Mexico requires the operator to demonstrate that the wells casing and cementing are mechanically and physically sound and demonstrate both internal and external mechanical integrity of the well is achieved. N.M. Code, § 19.15.25.

⁸⁶ Alaska requires this information to be submitted with an application to suspend a well. 20 AAC § 25.110.

(iv) Pose no threat to the health and safety of persons, property or the environment.

(2) The well complies with **one of the following:**

~~—(i) The well meets casing and cementing requirements of §§ 78.81—78.86 (relating to casing and cementing).~~

~~—(ii) For wells not drilled in conformance with casing and cementing requirements of §§ 78.81—78.86, and for the purpose of the annual monitoring of wells granted inactive status as required by § 78.103 (relating to annual monitoring of inactive wells), the applicant demonstrates that:~~

~~—(A) For oil and gas wells equipped with surface casing, the operator shall demonstrate that the liquid level in the well bore is maintained at a level at no higher than the water protection depth. For purposes of this clause where oil or gas bearing formations are encountered less than 100 feet below the surface casing seat, the water protection depth shall be that point midway between the top of the oil or gas bearing formation and the surface casing seat.~~

~~—(B) If the liquid level in an oil or gas well equipped with surface casing stands above the water protection depth and below the groundwater table depth, the operator shall test the liquid to determine its quality. If the liquid has a total dissolved solids content or conductivity generally equivalent to fresh groundwater in the immediate area, the casing is assumed to be either leaking or not set deep enough to shut off groundwater, and mechanical integrity is not demonstrated and inactive status will not be granted unless the operator demonstrates that the well is in compliance with the shut-in portion of the mechanical integrity test requirements of the Under Ground Injection Control program under the Safe Drinking Water Act (21 U.S.C.A. § 349; 42 U.S.C. § § 201, 300f—300j-11). If the liquid has a total dissolved solids content or conductivity equivalent to the production formation or production liquid, mechanical integrity is considered to be demonstrated.~~

~~—(C) For oil wells not equipped with surface casing or for oil wells equipped with surface casing that cannot be approved for inactive status under paragraph (2)(ii)(A) or (B), the operator shall modify the well to meet one of the following:~~

~~—(I) The operator shall set a string of casing on a packer sufficiently deep to isolate the fresh groundwater system. The casing shall be set to the water protection depth for wells in the area, and the requirements of paragraph (2)(ii)(A) or (B) shall be met.~~

~~—(II) The operator has set a temporary plug or mechanical seal at the water protection depth and isolated the fresh groundwater system. The operator may demonstrate the integrity of the plug by demonstrating that water standing above the plug is, and continues to be, fresh water not contaminated by production fluids, or by other means acceptable to the Department.~~

~~—(III) The operator shall fill the well with a freshwater bentonite gel or other material approved by the Department which will restrict vertical migration of gas or fluids in the well bore. The operator shall monitor the gel level and report significant changes to the Department on an annual basis and take remedial action approved by the Department.~~

~~—(D) For gas wells equipped with production casing separate from the surface casing, the annulus between the surface or coal protective casing and the production casing is vented to the atmosphere. The owner or operator of a well granted inactive status under this clause shall monitor the annular vents for gas flow volumes. If the gas flow volume~~

~~exceeds 5,000 cubic feet per day, the owner or operator shall notify the Department and take remedial action approved by the Department.~~

~~—(E) For gas wells not equipped with separate production casing, but with cemented or uncemented surface casing present, the produced gas shut-in pressure is less than the pressure necessary to cause gas migration into the adjacent formation at the surface casing seat. Compliance with this condition may be demonstrated by mechanical tests of the casing and by evidence that the gas wellhead shut-in pressure does not exceed 0.433 psi per foot of surface or coal protective casing depth.~~

(3) If gas exists at an inactive oil well, the operator ~~may vent the gas to the atmosphere or~~ **must capture it for use or sale as fuel**, equip the well to confine the gas to the producing formation, **or permanently plug and abandon the well**. If this gas flow is greater than 5,000 cubic feet per day, the owner or operator shall notify the Department and take remedial action approved by the Department.

(4) The applicant shall certify that the well is of future utility and shall present a viable plan for utilizing the well within ~~a reasonable time~~ **the five year period allowed for inactive status under §§ 78.101 and 78.104**. In addition to providing information to demonstrate compliance with paragraphs (1) and (2), the application for inactive status shall include the following:

(i) A plan showing when the well will be used **within the five-year period allowed for inactive status under §§ 78.101 and 78.104**.

(ii) A certification identifying that one of the following applies:

(A) Significant reserves remain in place and the operator plans to produce the well.

(B) The well will be used as a disposal well.

(C) The well will be used as a storage well.

(D) The well will be used as an observation well.

(E) The well will be used as a secondary or tertiary recovery injection well or that the well will be used for other purposes specified by the applicant.

(iii) Wellbore diagrams illustrating the current and proposed mechanical configuration and condition of the well during inactive status.

~~(iv)~~ Other information necessary for the Department to make a determination on inactive status.

(5) A petroleum engineer must complete a record review of the well's condition, conduct an on-site inspection, conduct a mechanical integrity test, and certify that the requirements of § 78.102 (1)-(4) have been met. The petroleum engineer's report must be included in the application to the Department for consideration of inactive well approval. The petroleum engineer's report must include photographs of the wellhead, well pressure readings, a copy of the mechanical integrity test, and confirmation that there was not discoloration, fluid or sheen visible on the ground near the well or in any nearby water.

§ 78.103 Annual Monitoring of Inactive Wells

Proposed Regulation: The EQB proposes a revision to language of § 78.103 to clarify that the notice requirement is three business days.

Comment: We do not support a three-business-day notification period. A three-day period is too short for the PADEP to plan for and schedule inspectors to be at the well site. We recommend that proposed § 78.103 be further revised to require notice of at least 7 working days.

We do not support only annual inspections of inactive wells. This limited inspection schedule could result in a leaking well going undetected and unmonitored for a year. We recommend the operator be required to inspect inactive wells on a monthly basis and immediately report and remedy any problems found during the inspection.

The regulation is unclear about what type of monitoring and testing is required. We recommend this rule be clarified to read that monthly visual monitoring be conducted from the surface and that a mechanical integrity test be completed annually.

We recommend that a petroleum engineer be required to complete a record review of the well's condition, conduct an on-site inspection, conduct a mechanical integrity test on the well, and certify that the requirements of § 78.102(1)-(4) have been met on an annual basis. This requirement will give the PADEP confidence that an engineer with specific expertise has examined the well condition and has certified that inactive status is still safe and appropriate for this well.

We recommend the following revisions of § 78.103:

§ 78.103. ~~Annual m~~Monitoring of inactive wells.

The owner or operator of a well granted inactive status shall monitor the integrity of the well on a monthly basis, conduct an annual mechanical integrity test on the well, and ~~shall~~ report the results to the Department.

Any deficiency found during the inspection must be immediately remedied and a record of the work completed be submitted to the Department within 7 days of completion.

The owner or operator shall give the Department ~~3~~ 7 **[working] business** days prior notice of the annual and monthly monitoring and mechanical integrity testing.

A petroleum engineer must annually complete a record review of the well's condition, conduct an on-site inspection, conduct a mechanical integrity test, and certify that the requirements of § 78.102 (1)-(4) have been met. The petroleum engineers report must be submitted to the Department annually.

~~For wells that were drilled in accordance with the casing and cementing standards of §§ 78.81—78.86 (relating to casing and cementing), the operator shall monitor the integrity of the well by using the method described in § 78.102(2)(ii)(A), (B), (D) or (E) (relating to criteria for approval of inactive status), as appropriate.~~

~~For a well that was not drilled in accordance with the casing and cementing standards, the wells shall be monitored in accordance with § 78.102(1).~~ To qualify for continued inactive status, the owner or operator shall demonstrate, by the data in the monitoring reports, that the condition of the well continues to satisfy the requirements of § 78.102. ~~The owner or operator shall submit the report by March 31 of the following year.~~

§ 78.104 Term of Inactive Status

Proposed Regulation: The EQB did not propose a revision to § 78.104 for the term of inactive wells.

Comment: We recommend that § 78.104 be amended to limit the maximum term for an inactive well for a period of 5 years, without the opportunity for unlimited numbers of annual extensions.⁸⁷ This limit will ensure that inactive wells that do not have a beneficial use after five years are properly plugged and abandoned to reduce environmental risk, while the operator is actively working in the well area and is solvent. If the EAB does not support a 5-year limit, it should explain why unlimited numbers of annual extensions are appropriate.

We also recommend that the PADEP's approval of inactive wells be made publically available on the PADEP website, with an explanation of why the PADEP granted the approval and a copy of the application.

We recommend that § 78.104 be revised as follows:

§ 78.104. Term of inactive status.

Approval of inactive status for a well is valid for 5 years unless revoked. After 5 years, the owner or operator shall plug or return to active status a well granted inactive status, ~~unless the Department grants an application for a 1-year extension. The operator of a well granted inactive status may apply for renewal of inactive status by demonstrating that the well continues to satisfy the conditions imposed on the well by §§ 78.102 and 78.103 (relating to criteria for approval of inactive status; and annual monitoring of inactive wells).~~

A copy of the Department's approval shall be made publically available on the Department website within 15 days of approval, with an explanation of why the Department granted the approval and a copy of the application.

§ 78.121 Production Reporting

Proposed Regulation: The EQB proposes a revision to language of § 78.121 to require all unconventional wells to submit bi-annual reports.

Comment: We recommend several amendments to § 78.121. First, we recommend that all wells in Pennsylvania be required to file consistent amounts of production reporting information and that the two-tier reporting system be eliminated. Second, we request that the production reporting data be made available to the public on the PADEP's website. We also recommend that the waste manifests be reported, including a characterization of the waste.

We recommend that § 78.121 be revised as follows.

§ 78.121. Production reporting.

⁸⁷ BLM requires that no well be temporarily abandoned for more than 30 days without BLM approval, and then BLM grants only 12-month temporary abandonment approvals. 43 CFR § 3162.3-4(c). Alabama Rule 400-2-4-.14 limits temporary abandonment or well shut-in to one-year periods.

(a) ~~The well operator shall submit an annual production and status report for each permitted or registered well on an individual basis, on or before February 15 of each year. [The operator of a well permitted to produce gas from the Marcellus shale formation]~~ Each operator of an **unconventional well** shall submit a production and status report for each well on an individual basis, on or before February 15 and August 15 of each year. Production shall be reported for ~~the preceding calendar year or in the case of [a Marcellus shale] an unconventional well, for~~ the preceding ~~{6 months}~~ reporting period. When the production data is not available to the operator on a well basis, the operator shall report production on the most well-specific basis available. The annual production report must include information on the amount and type of waste produced and the method of waste disposal or reuse, **including a waste manifest and waste characterization data**. Waste information submitted to the Department in accordance with this subsection is deemed to satisfy the residual waste biennial reporting requirements of § 287.52 (relating to biennial report). **Production reporting data shall be made publically available by the Department on its website within 30 days of receipt.**

§ 78.122 Well Record and Completion Report

Proposed Regulation: The EQB proposes a revision to language of § 78.122 to make the well record and completion reporting requirements consistent with the statute.

Comment: We support some of the improvements, but overall find that the reporting requirements do not provide the PADEP with an adequate record of the work completed on the well. We recommend that the proposed requirements at § 78.122 be expanded to include submission of a complete description of the sequence of events during all required blow-out prevention tests and copies of test results,⁸⁸ the grade and weight of each casing,⁸⁹ the final cementing report,⁹⁰ a driller's log (including the results of coring, electric log, mud-logging, or testing completed),⁹¹ an as-built well construction drawing, directional survey, and test data.⁹² We also recommend that the operator (who holds the permit) be required to gather the data and ensure that the terms of its permit are met.

We recommend that proposed § 78.122 be revised as follows:

§ 78.122. Well record and completion report.

⁸⁸ California requires operators to submit a detailed well history that includes the chronological order on a daily basis all significant operations carried out and equipment used during all phases of drilling, testing, completion, recompletion and plugging and abandonment of the well. *See* Calif. Code Regs., tit. 14, § 1937.1.

⁸⁹ Alabama requires a completion report to be submitted on Form OGB-7 and requires casing size, grade and weight. *See* <http://www.ogb.state.al.us/documents/ogbforms/OGBForms/ogb07form.pdf>. New Mexico requires a completion report to be submitted on Form C-105. *See* N.M. Code, § 19.15.16. Form C-105 requires casing size, grade and weight.

⁹⁰ Alabama requires a completion report to be submitted on Form OGB-7 and requires information on the amount of cement used, depth it was placed, date it was installed, the type of cement, pressure test results and the name of the service company that installed the cement. *See* <http://www.ogb.state.al.us/documents/ogbforms/OGBForms/ogb07form.pdf>.

⁹¹ California and Texas require that operators submit log results. Calif. Code Regs., tit. 14, § 1724.; Texas Admin. Code § 3.16(c-d).

⁹² Alaska's well completion report requires submittal of a final well schematic diagram on Form 10-407. *See* <http://doa.alaska.gov/ogc/forms/10-407.pdf>. North Dakota requires that operators have their contractors submit a directional survey as part of their well completion Form 6, which also requires detailed testing information. *See* <https://www.dmr.nd.gov/oilgas/rules/forms/form6.PDF>.

(a) For each well that is drilled or altered, the operator shall keep a detailed drillers log at the well site available for inspection until drilling is completed. Within 30 calendar days of cessation of drilling or altering a well, the well operator shall submit a well record to the Department on a form provided by the Department that includes the following information:

- (1) Name, address and telephone number of the permittee.
- (2) Permit number, and farm name and number.
- (3) Township and county.
- (4) Date drilling started and completed.
- (5) Method of drilling. **A complete description of the sequence of events during all required blow-out prevention tests and copies of test results.**
- (6) Size and depth of conductor pipe, surface casing, coal protective casing, intermediate casing, production casing and borehole, **and the grade and weight of each casing. A complete description of the sequence of events during all required casing tests and copies of test results.**
- (7) **Type and amount of cement and results of cementing procedures. The final cementing report, including: cement type and grade; list of all cement additives; mix water pH and temperature; cement volume, yield, and density; amount of cement returned to surface; cement pumping rate and pressures; a complete description of the sequence of events during the cementing operation; and a copy of all temperature logs and cement evaluation tool tests.**
- (8) Elevation and total depth.
- (9) Drillers log that includes the name and depth of formations from the surface to total depth, depth of oil and gas producing zone, depth of fresh water and brines and source of information. **The depth of lost circulation zones, depth of over-pressured zones and pressure. The results of coring, electric log, mud-logging, or testing completed.**
- (10) **An as-built well construction drawing, a directional survey, along with a copy of the final casing and cementing report, signed by the well owner and the well owner/operator's lead engineer certifying Certification by the operator** that the well has been constructed in accordance with this chapter and any permit conditions imposed by the Department.
- (11) **Whether methane was encountered other than in a target formation, the location of the gas, and test or log data collected.**
- (12) **The country of origin and manufacture of tubular steel products used in the construction of the well.**
- (13) **The borrow pit used for well site development, if any.**

[(11)] (14) Other information required by the Department.

(b) Within 30 calendar days after completion of the well, ~~when the well is capable of production,~~ the well operator shall ~~submit~~ ~~arrange for the submission of~~ a completion report to the Department on a form provided by the Department that includes the following information:

- (1) Name, address and telephone number of the permittee.
- (2) Name, address and telephone number of the service companies.
- (3) Permit number and farm name and number.
- (4) Township and county.
- (5) Perforation record.

- (6) Stimulation record which includes the following:
- (i) A descriptive list of the chemical additives in the stimulation fluid, including any acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor and surfactant.
 - (ii) The percent by ~~volume~~ **and** mass of each chemical additive in the stimulation fluid.
 - (iii) **[A list of the chemicals in the Material Safety Data Sheets, by name and chemical abstract service number, corresponding to the appropriate chemical additive.] The trade name, vendor and a brief descriptor of the intended use or function of each chemical additive in the stimulation fluid.**
 - (iv) **[The percent by volume of each chemical listed in the Material Safety Data Sheets.] A list of the chemicals intentionally added to the stimulation fluid, by name and chemical abstract service number, and the chemical characteristics of the base fluid if it does not meet the freshwater definition at § 78.1.**
 - (v) **The maximum concentration, in percent by volume and mass, of each chemical intentionally added to the stimulation fluid and contained in the base fluid.**
 - ~~[(v)]~~ (vi) The total volume of the base fluid.
 - ~~[(vi)]~~ (vii) A list of water sources used under an approved water management plan and the volume of water used from each source.
 - ~~[(vii)]~~ (viii) The total volume of recycled water used.
 - ~~[(viii)]~~ (ix) The pump rate and pressure used in the well.
 - (7) Actual open flow production and shut in surface pressure.
 - (8) Open flow production and shut in surface pressure, measured 24 hours after completion.
 - (9) The freshwater ~~and centralized~~ impoundment, if any, used in the development of the well.**
 - (c) When the well operator submits a stimulation record, it may designate specific portions of the stimulation record, **other than the chemicals intentionally added to the stimulation fluid or in the base fluid and the maximum concentrations thereof,** as containing a trade secret or confidential proprietary information. **The operator shall have the burden of proving, and shall submit with the stimulation record evidence proving, that any so designated portion of the record is a trade secret or confidential proprietary information.** The Department ~~will~~**shall review the submitted evidence, make a determination whether the operator has satisfied its burden of proof as to each designated portion of the record, and** prevent disclosure under the Right-to-Know Law (65 P. S. §§ 67.101—~~[67.3103] 67.3104~~) **only** of the designated confidential information **proven to be a trade secret or confidential proprietary information**~~to the extent permitted or other applicable State law.~~
 - [(d) In addition to submitting a stimulation record to the Department under subsection (b), and subject to the protections afforded for trade secrets and confidential proprietary information under the Right-to-Know Law, the operator shall arrange to provide a list of the chemical constituents of the chemical additives used to hydraulically fracture a well, by chemical name and abstract service number, unless the additive does not have an abstract service number, to the Department upon written request by the Department.]**

Subchapter G, Bonding Requirements

Proposed Regulation: The EQB proposes revisions to Subchapter G. Bonding Requirements (§§ 78.301 – 78.314) with the intent of aligning the regulations with the recent changes to § 3225 of the Act.

Comment: We support the PADEP's collection of bonds and other forms of financial security before issuing well permits. Bonds and other forms of financial assurance require potential polluters to demonstrate—before the fact—that there is sufficient funding to correct and compensate for property, health, and natural resource damages and to fund resource reclamation obligations. However, we are concerned that the amount and type of financial assurance required by § 3225 of the Act is insufficient to meet the stated purpose of § 3225 of the Act. We recommend the EQB propose legislative amendments to § 3225 of the Act to make improvements in the amount and type of financial assurance required.

Foremost, we are concerned that the bond amount collected is based solely on the cost to plug and abandon a well. This is inconsistent with § 3225(a)(1) of the Act's stated intent to provide funds to cover *all* drilling, water supply replacement, restoration and plugging requirements. If the stated purpose of requiring a bond is to provide funds for damage that may arise during drilling operations, to correct adverse impacts to water supplies (including replacement), and to provide funds to restore the well site or plug the well, then the amount of the bond should include all these potential liabilities, not just the cost of plugging the well.

It is our position that operators should be required to hold bonds and/or pollution insurance in an amount sufficient to cover *all* drilling, water supply replacement, restoration and plugging requirements, and that operators that are unable to obtain a bond due to an inability to demonstrate sufficient financial resources should not be allowed to operate in Pennsylvania.

During the last revision to § 3225(a)(1)(i), the bond amount of \$2,500 per well was increased to \$4,000 per well (less than 6000' deep) and \$10,000 per well (6,000' or deeper). While, the bond increase was an improvement, these amounts are still well below the actual cost to plug and abandon a well and do not provide funds to address the other costs the Act proposes to cover. By comparison, Colorado uses a substantially higher cost estimate of \$10,000 for wells less than 3,000' deep and \$20,000 for wells 3,000' deep or greater, and requires several other types of financial assurance to address to correct and compensate for property, health, and natural resource damages and to fund resource reclamation obligations.⁹³ California requires a bond of \$25,000 for each well up to 10,000' deep, and \$40,000 for wells over 10,000' deep, plus a bond of \$5,000 for each idle well more than 5 years old.⁹⁴

We recommend that the EQB gather information on the actual current cost to plug and abandon wells in Pennsylvania. Based on that information, we request that the EQB propose legislative changes to increase the amount of financial security to plug and abandon both new and existing wells.

We also recommend that the EQB gather information on the actual current cost to correct and compensate for property, health, and natural resource damages and to fund resource reclamation obligations. Based on that information, the EQB should propose legislative changes to increase the amount of financial security required.

During the last revision to § 3225 the maximum statewide blanket bond of \$25,000 for a company drilling wells less than 6,000' deep was increased to \$35,000 (for 1-50 wells) and to \$250,000 (more than 250 wells). The maximum statewide blanket bond for wells 6,000' and deeper was raised to \$140,000 (for 1-25 wells) and to \$600,000 (more than 150 wells). While increases in the maximum statewide blanket bond amounts are an improvement over the prior cap of \$25,000 per operator, the statewide blanket bond

⁹³ Colo. Oil & Gas Comm'n, 700. Series Rules, Financial Assurance, Rule 706.

⁹⁴ Calif. Dep't of Conserv., Div. of Oil, Gas, and Geothermal Res., Bond Information (Feb. 2014)

will be insufficient to plug all the wells owned by a single operator (existing and new) and address other damages if an operator were to go bankrupt. By comparison, California requires a statewide blanket bond of \$2,000,000⁹⁵ and Colorado requires an additional \$10,000 to \$20,000 per idle well over and above its statewide blanket financial assurance requirement to ensure there are sufficient funds to address both new wells and the backlog of idle wells that still have yet to be plugged.⁹⁶

For example, the EQB estimates a cost of \$10,000 per well to plug and abandon a well 6,000' or deeper. If the operator has 150 wells, the total cost to actually complete the plugging work would be \$1,500,000. Therefore, the proposed maximum blanket bond cap of \$600,000 falls \$900,000 short to complete the plugging and abandonment work alone; there would be no funds left to address other damages or restoration required under the Act. If the operator has more than 150 wells or if adverse impacts to water supplies (including replacement), or restoration the well site must be completed, the funding shortfall grows.

The statewide blanket bond reduces the per well bond amount by offering a reduced rate based for operators with large numbers of wells. For example, if an operator in Pennsylvania just has one well (6,000' or deeper), it must have a \$10,000 bond for that well. However if an operator in Pennsylvania has more than 150 wells (6,000' or deeper), it is only required to have a \$600,000 maximum statewide blanket bond, which equates to \$4,000 per well. If the cost to plug a well is actually \$10,000 (as currently estimated by Pennsylvania), then there will be an actual shortfall of \$6,000 per well if an operators goes bankrupt. This means that if an operator goes bankrupt, and the bond must be used to plug all 150 wells (in this scenario) the bond would be \$900,000 short. The amount of the bond should be consistent with the actual cost. Discounts should not be given to operators with larger numbers of wells.

We oppose the bond alternatives provided in § 3225(d) that afford substantial leniency to operators that are unable to obtain a bond due to an inability to demonstrate sufficient financial resources. The bond alternatives provided in § 3225(d) allow operators that are not able to obtain a bond to pay a fraction of the bond cost over a period of time. Operators that are unable to obtain a bond due to an inability to demonstrate sufficient financial resources should not be granted a permit to drill oil and gas wells in Pennsylvania. All applicants should be required to meet the same financial standards, without waiver.

We are concerned that § 3225 of the Act includes no financial responsibility requirement to address general pollution liability, surface facilities, and seismic operations (in addition to well plugging and abandonment costs) for oil and gas operators. By comparison, California, Ohio Colorado, and Alaska require substantially more financial assurance for oil and gas operators in total.

To provide the best protection, we recommend that the EQB propose legislative changes to § 3225 of the Act that consider California, Ohio, Colorado, and Alaska financial assurance requirements explained below.

- Colorado requires financial assurance to: protect surface owners that are not party to a lease (Rule 703); reclaim centralized exploration and production waste management facilities (Rule 704); conduct seismic operations (Rule 705); plug and abandon new wells (Rule 706); plug and abandon existing inactive wells (Rule 707); provide \$1,000,000 in general liability insurance (Rule 708); and, address damages that could occur from natural gas facilities (Rule 711) and injection wells (Rule 712).⁹⁷

⁹⁵ Calif. Dep't of Conserv. Div. of Oil, Gas, and Geothermal Resources, Bond Information (Feb. 2014).

⁹⁶ Colo. Oil & Gas Comm'n, 700. Series Rules, Financial Assurance, Rule 707.

⁹⁷ Colo. Oil & Gas Comm'n, 700. Series Rules, Financial Assurance.

Rule 703 requires operators to provide financial assurance to the Commission, prior to commencing any operations with heavy equipment, to protect surface owners who are not parties to a lease, surface use or other relevant agreement with the operator from unreasonable crop loss or land damage caused by such operations. Financial assurance of \$2,000 per well for non-irrigated land, or \$5,000 per well for irrigated land, or a statewide, blanket financial assurance of \$25,000 is required.

Rule 704 requires operators of centralized exploration and production waste management facilities to provide the Commission financial assurance in an amount equal to the estimated cost necessary to ensure the proper reclamation, closure, and abandonment of such facility.

Rule 705 requires operators conducting seismic operations (ahead of drilling to determine where to drill) to provide a statewide blanket of financial assurance, in the amount of \$25,000, to ensure proper plugging and abandonment of any shot holes and any required surface reclamation.

Rule 706 requires operators to provide a financial assurance for each new well permitted to provide funding to plug and abandon that well in the future. The amount of the bond is \$10,000 for wells less than 3,000' deep and \$20,000 for wells 3,000' deep or greater. Alternatively, a statewide blanket financial assurance of \$60,000 (for 1-100 wells) or \$100,000 (for more than 100) wells is required.

Rule 707 provides funding for inactive wells. The operator must provide an additional \$10,000 for wells less than 3,000' deep and \$20,000 for wells 3,000' deep or greater for each inactive well if the funding provided in the statewide blanket financial assurance under rule 706 is insufficient to cover the total number of wells owned/operated.

Rule 708 requires the operator to provide \$1,000,000 in general liability insurance.

Rule 711 requires natural gas gathering, natural gas processing, and underground natural gas storage facilities to provide \$50,000 for statewide blanket of financial assurance.

Rule 712 requires Class II Commercial Underground Injection Control (UIC) wells to provide \$50,000 for statewide blanket of financial assurance for each injection facility.

- California requires a bond of \$25,000 for each well up to 10,000' deep, and \$40,000 for wells over 10,000' deep, plus a bond of \$5,000 for each idle well more than 5 years old.⁹⁸ Alternatively, an operator can obtain a blanket bond of \$200,000 for 1-50 onshore wells (\$5,000 for each idle well more than 5 years old), or \$400,000 for more than 50 onshore wells (\$5,000 for each idle well more than 5 years old), or a blanket bond of \$2,000,000 that covers all onshore wells including idle wells. The bond funds are available to California if an operator fails to plug and a plug and abandon a well; but it can also be forfeited for other reasons, such as a failure to clean up a spill or screen a sump associated with a well.
- Ohio requires a well bond and insurance. A surety bond for single well is \$5,000, \$10,000 for two wells, or a blanket bond for all wells of \$15,000.⁹⁹ Additionally, liability and bodily injury coverage not less than \$1,000,000 must be maintained until all wells are plugged or transferred to another

⁹⁸ Calif. Dep't of Conserv., Div. of Oil, Gas, and Geothermal Res., Bond Information (Feb. 2014).

⁹⁹ Ohio Rev. Code (ORC) ch. 1509 ; Oh. Admin. Code (OAC) § 1501:9-1-03 (A).

insured owner. In urban areas, all well owners shall obtain liability insurance of not less than \$3,000,000 for bodily injury and property damage coverage.¹⁰⁰

- Alaska requires a \$100,000 bond for each well, or a blanket bond of \$200,000 for all wells in the state. An applicant can obtain approval for a bond less than \$100,000 if it can show that the cost of well abandonment and location clearance will be less than \$100,000.¹⁰¹ Additionally, Alaska requires financial responsibility of: \$1,670,000 per incident for onshore oil exploration and production facilities less than 2,500 barrels of oil per day; \$8,360,000 for oil production facilities 2,500 to less than 5,000 barrels of oil per day; \$16,720,000 for oil production facilities 5,000 to less than 10,000 barrels of oil per day; and \$33,440,000 for oil production facilities more than 10,000 barrels of oil per day.¹⁰²

Section 3225(a)(1) of the Act requires bonds for wells drilled on or before April 18, 1985:

A bond for a well in existence on April 18, 1985, shall be payable to the Commonwealth and conditioned upon the operator's faithful performance of all water supply replacement, restoration and plugging requirements of this chapter.

The proposed regulations do not require a bond for wells drilled before April 18, 1985. Therefore, the proposed regulations are inconsistent with the revised statute. Section 3225(a)(1) of the Act requires new well bonds to cover all drilling, water supply replacement, restoration and plugging requirements, and wells drilled on or before April 18, 1985 to cover water supply replacement, restoration, and plugging requirements. This key component of the statute is not reflected in the regulations. We recommend that the purpose for the bonds be clearly stated in the regulation.

We are also concerned that § 3225(a)(3) and § 3225(b) has an internal inconsistency about when liability under the bond is released. Section 3225(a)(3) states that liability under the bond continues until one year after the well is plugged and the plugging certificate is filed with the PADEP. Section 3225(b) states that liability under the bond is not released until the requirements of § 3225(a) are met, which includes more than just plugging the well. The bond should not be released until plugging, water supply replacement and restoration obligations are all complete. We believe the more stringent of the two should be codified in the regulations.

¹⁰⁰ ORC § 1509.07.

¹⁰¹ 20 AAC § 25.025(b). A bond and, if required, security must be in the amount of not less than \$100,000 to cover a single well or not less than \$200,000 for a blanket bond covering all of the operator's wells in the state, except that the commission will allow an amount less than \$100,000 to cover a single well if the operator demonstrates to the commission's satisfaction in the application for a Permit to Drill (Form 10-401) that the cost of well abandonment and location clearance will be less than \$100,000.

¹⁰² 18 AAC § 75.235

Appendix A

Throughout the foregoing comments, we made specific recommendations for improvements to the proposed revisions of Chapter 78. We are troubled by the failure of the EQB to include supporting scientific and technical documents with the regulatory package.

Our comments included recommendations with respect to the topics addressed below. Should the EQB reject those recommendations, this Appendix provides less protective alternative suggestions for improvement of some of the proposed regulations. We request that the EQB provide scientific and technical data and analysis to support the next version of the proposed regulations, so that we can better understand the basis for any decisions inconsistent with our preferred recommendations or alternative suggestions.

Induced Seismicity

Proposed Regulation: Not applicable.

Comment: The proposed regulations do not address the potential for induced seismicity related to well stimulation, including hydraulic fracturing, or include requirements that the operator examine and mitigate the potential impact. Hydraulic fracturing has been confirmed or is suspected as the cause of induced seismicity strong enough to be felt at the surface in a number of incidents.

- In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Shortly after several stages of the Preese Hall 1 well were fracture stimulated, 50 seismic events were observed with a maximum magnitude of 2.3 M_L .¹⁰³
- A report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8 M_D , could have been induced by hydraulic fracturing.¹⁰⁴
- A total of 38 seismic events were recorded by the Canadian National Seismograph Network (CNSN) in the Etsho and Tattoo areas of the Horn River Basin between 2009 and 2011, ranging in magnitude from 2.2 to 3.8 M_L . After reviewing the locations, depths, and magnitudes of the earthquakes and comparing them to the timing and location of hydraulic fracturing, the researchers concluded that fracturing resulted in slippage along pre-existing faults, which caused the earthquakes. In all but one case, the earthquakes occurred along faults that had not previously been mapped.¹⁰⁵

Induced seismicity can result in environmental and human health impacts identical to those caused by natural earthquakes of similar intensity, including the potential for property damage and injury.

¹⁰³ C.J. de Pater & S. Baisch, *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report 71* (2011) (prepared for Cuadrilla Resources Ltd).

¹⁰⁴ A. Holland, *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma* 31 (2011) (Oklahoma Geological Survey, Open-File Report OF1-2011).

¹⁰⁵ BC Oil and Gas Comm'n, *Investigation of Observed Seismicity in the Horn River Basin* 29 (2012).

Earthquakes may also result in changes to groundwater or surface water level or quality.¹⁰⁶ Seismicity can also compromise wellbore integrity by damaging the cement sheath and metal casing installed as pressure control and ground water protection barriers. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250-foot length.¹⁰⁷ Deformation of the metal casing wall may crack inflexible cement that is placed in the annulus between the metal casing and the wellbore. Damage to the cement bond could allow fluids (gas and liquids) to migrate upwards and potentially contaminate the groundwater it was intended to protect. Even in the absence of actual damage, induced seismic events can be a nuisance to communities and a source of anxiety; they also may have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

We recommend that the EQB, in consultation with the Pennsylvania Geological Survey, develop regulations to address induced seismicity. Operators should be required to evaluate seismic risk and the potential for induced seismicity at a proposed well site. This evaluation should include an analysis of background seismicity, local geology (including faults and tectonically active features), local and regional stress state, proposed stimulation practices, and nearby instances of induced seismicity. The evaluation also should include: an evaluation of the maximum magnitude of an earthquake that could be induced based on anticipated injection volume;¹⁰⁸ the probability that such an earthquake may occur, based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, minimum horizontal stress; and anticipated pore pressure as a result of fluid injection.¹⁰⁹ The results of this evaluation should be provided with the permit application.

Researchers at Lawrence Berkeley National Laboratory¹¹⁰ and the National Academy of Sciences¹¹¹ have published detailed information on the elements that should be considered for inclusion in a protocol for addressing induced seismicity, including but not limited to:

- Plans for outreach and communication with the public, regulators, and other stakeholders about seismic hazard, mitigation, and any incidents of induced seismicity. This includes involving stakeholders at all phases of the project, providing meaningful opportunities for input, and being responsive to stakeholder questions and concerns.
- Selecting criteria for damage, vibration, and noise to assess the potential impact of induced seismicity on the built environment and human activity. This includes identifying thresholds for damage to structures, ground shaking, and noise, below which no impact would occur. At a minimum, impact criteria should be evaluated for: buildings; civil structures, such as bridges,

¹⁰⁶ See, e.g., G.M. Fleeger, *et al.*, USDOI, USGS, *Hydrologic Effects of the Pymatuning Earthquake of September 25, 1998, in Northwestern Pennsylvania* (1999); C.Y. King, *et al.*, *Earthquake-induced groundwater and gas changes*, 163 *Pure and Applied Geophysics* 633-45 (2006).

¹⁰⁷ *Id.* n. 1.

¹⁰⁸ See, e.g., A. McGarr, *Maximum Magnitude Earthquakes Induced by Fluid Injection*, *J. of Geophysical Research: Solid Earth* (2014); M. Hallo, *Prediction of Magnitude of the Largest Potentially Induced Seismic Event*, *J. of Seismology* 1-11 (2014).

¹⁰⁹ See, e.g., S.A. Shapiro, *et al.*, *Probability of a Given-Magnitude Earthquake Induced by a Fluid Injection*, 34 *Geophysical Research Letters* 22 (2007).

¹¹⁰ See, e.g., E. Majer, *et al.*, *Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems*. U.S. Dep't of Energy. (2012); E. Majer, *et al.*, *Best Practices for Addressing Induced Seismicity Associated With Enhanced Geothermal Systems (EGS)*, U.S. Dep't of Energy (2013).

¹¹¹ D. Clarke, *et al.*, *Induced Seismicity Potential in Energy Technologies*, National Academies Press (2012).

highways, tunnels, etc.; buried structures, such as wells, pipelines, and basement walls; landslides; human response to vibration and noise; and laboratory and manufacturing facilities, particularly those with equipment that may be sensitive to ground vibration.

- An assessment of site-specific natural and induced seismic hazard. This study may include both probabilistic and deterministic seismic hazard assessments. The analysis of natural seismicity hazard will serve as a baseline against which to compare induced seismicity hazard and should include an evaluation of the seismic history of the region, fault identification and characterization, geologic site characterization, ground motion models, and the generation of hazard curves and maps. The induced seismicity hazard assessment may include an evaluation of local geology and existing seismic monitoring data, review of known instances of induced seismicity, available predictive models for induced seismicity maximum magnitude, ground motion models, and the generation of hazard curves and maps. Limited data may be available to evaluate induced seismic hazard and therefore it is critical that these assessments be updated as additional data become available.
- Probabilistic and scenario risk assessments. Several different scenario assessments may be appropriate but, at a minimum, the assessments should include a “worst case” scenario analysis. These analyses should include: vulnerability assessments for possible receptors including residential and community buildings; commercial, industrial, research, and medical facilities; infrastructure; socioeconomic impacts, including business disruptions; and, nuisance due to vibration or noise. Particular attention should be paid to older structures, and plugged and abandoned wells. The costs of consequences should also be evaluated, including monetary costs due to physical damage or loss as well as non-physical damages such as nuisance. Risk should be assessed for both natural and induced seismicity to enable comparisons.
- Seismic monitoring. This includes real-time seismic monitoring before, during, and after stimulation activities. The design and placement of the monitoring array should at a minimum take into account the location of potential seismic sources and background seismicity, the location of sensitive receptors, depth and seismic properties of the formation that will be fractured, necessary sensitivity, and predicted size of the fracture network.
- A mitigation plan based on the hazard and risk assessments. If necessary, based on the results of the hazard and risk assessments, the proposed hydraulic fracture design should be revised to control the level and impact of induced seismicity. Operators should also develop an appropriate “traffic light” control system for responding to an instance of induced seismicity. Under a traffic light system, increases in induced seismic activity beyond predetermined thresholds trigger actions by the operator, which may include additional monitoring, reducing injection volume or pressure, or ceasing operations completely. Thresholds may be based on earthquake magnitude, intensity of ground motion, or other measures. The threshold levels and required actions by operators when those thresholds are exceeded must be developed based on site-specific conditions.

Subsurface waste water injection also has been documented to cause induced seismicity.¹¹² While recognizing that the PADEP does not have primacy to implement the Underground Injection Control

¹¹² See, e.g., D.F. Sumy, *et al.*, *Observations of Static Coulomb Stress Triggering of the November 2011 M5.7 Oklahoma Earthquake Sequence*, *J. of Geophysical Research: Solid Earth* (2014); W.L. Ellsworth, *Injection-Induced Earthquakes*, *341 Science* 6142 (2013).

(UIC) program, we encourage the PADEP to coordinate with EPA Region 3 on addressing the risk of induced seismicity from Class II disposal wells. The same elements listed above should be considered for inclusion in a protocol to address induced seismicity from disposal wells.

In sum, we recommend that the EQB, in consultation with the Pennsylvania Geological Survey, develop regulations to address the risk of induced seismicity from hydraulic fracturing. The regulations should include requirements for operators to: (1) develop a stakeholder communications and outreach plan; (2) determine criteria for ground vibration and noise; (3) perform a hazard assessment; (4) perform a risk assessment; (5) conduct seismic monitoring, and; (6) develop mitigation plans. These elements should be developed using the operator's proposed hydraulic fracture design for that well along with site-specific data. Additional information and guidance on developing an appropriate protocol is available in the publications cited in the footnotes to this comment.

§ 78.1 Water Management Plan Definition

If the EQB disagrees with our recommendation at § 78.1, that WMPs should apply to all oil and gas wells, we request that the Board:

- (1) Provide an explanation of why not, or set a specific volume threshold for water use in any cases where detailed planning is not warranted; and,
- (2) Provide evidence that the proposed regulation would not result in adverse impacts to local water resources (e.g., the dewatering of streams).

§ 78.52a Abandoned and Orphaned Well Identification

If the EQB disagrees with our recommendation for improving the proposed regulation at § 78.52a, for abandoned and orphaned well identification, and allows the PADEP to issue permits without requiring all improperly abandoned wells (including orphaned wells) to be P&A'd according to the PADEP's requirements for long-term plugging and abandonment, we request that the EQB:

- (1) Explain how its proposal is consistent with Pennsylvania law;
- (2) Provide statistics on the number of improperly abandoned wells (including orphaned wells) in Pennsylvania;
- (3) Provide a quantitative technical assessment of the cumulative adverse impact these wells have had on the air, surface water, and groundwater; and,
- (4) Provide a projection of potential future cumulative impacts.

§ 78.57. Control, storage and disposal of production fluids.

In our comments at § 78.57, we supported the proposal to require removal of underground or partially buried storage tanks. However, we did not support the proposed waiver clause "unless approved by the Department." We requested that clause be deleted, because it was unclear under what circumstances the PADEP might allow the waiver. If the EQB envisions that the PADEP will waive the required removal of underground or partially buried storage tanks and the prohibition on their use, it should explain the circumstances where this would be allowed and define the criteria that would be used in issuing the waivers.

§ 78.59c Centralized Impoundments

In our comments at § 78.59c, we opposed the use of centralized impoundments for waste handling. We recommended that § 78.59c be deleted in its entirety. If the EQB disagrees with this recommendation, and considers the continued use of centralized impoundments, we request that the EQB provide a written scientific and technical analysis justifying the proposal, including:

- (1) A quantitative technical assessment of the amount of air pollution (by pollutant type) that will be emitted to the atmosphere from these impoundments and estimate the corresponding impact on human health and the environment;
- (2) The amount of pollution that could potentially impact groundwater sources from these pits;
- (3) Data on the historic use of centralized impoundments in Pennsylvania, including those known to have leaked or overflowed, and quantification of the cumulative adverse impact of these impoundments on air, soil, surface water, groundwater and animal life; and
- (4) A projection of future cumulative impact if the use of pits continues.

If, after this analysis is complete, the EQB finds that use of centralized impoundments provides a net environmental and human health benefit, we request that the EQB improve the centralized impoundment regulations as follows:

- (1) **Maximum Impoundment Size:** The use of large centralized impoundments requires large areas of surface excavation (cut) and embankment placement (fill). The proposed regulation does not include any upper limit on the size or depth of centralized impoundment. We request limits be set as follows: the greatest water depth at maximum storage is limited to 15 acre feet, and the greatest storage capacity at maximum storage elevation is less than or equal to 50 acre feet.
- (2) **Stream Setbacks:** None of the proposed setback distances in § 78.59c provide sufficient protection for water quality in the event of a centralized impoundment overtopping or surface discharge. A dam breach analysis should be required for all centralized impoundments, including a water quality analysis component to determine the appropriate project specific setbacks for centralized impoundments on an individual structure basis.

Stream setbacks should use the watercourse definition in 25 Pa. Code Chapter 105.1. Chapter 105 defines a watercourse as: "A channel or conveyance of surface water having defined bed and banks, whether natural or artificial, with perennial or intermittent flow." The United States Geologic Society 7.5 minute topographic quadrangle map blue lines do not have a formal process associated with their determination or documentation. Topographic blue lines should not provide a minimum setback standard for Pennsylvania streams.

Each centralized impoundment should provide documentation and analysis to support and justify the project-specific setbacks for that installation, sufficient to protect water quality.

- (3) **Seasonal High Water Table:** 25 Pa. Code Chapter 73 (Standards for Onlot Sewage Treatment Facilities) prohibits the installation of onlot sewage facilities if the seasonal high water table is within 20 inches (§ 73.14(a)(5)). There is no option for an alternate underdrain system if a seasonal high water table condition exists. The presence of a seasonal high groundwater table indicates a hydrologic connection to adjacent streams and wetlands, and hence, an additional path for direct contamination, should a leak or discharge from the impoundment occur. At a minimum, the Chapter 73 standards

should apply to centralized impoundments under Chapter 78.

Centralized impoundments should not be permitted within 20 inches of a seasonal high groundwater table, and should not be allowed to artificially lower the seasonal high groundwater table. The water quality implications from a centralized impoundment can be far more significant than an on-lot sewage treatment system; the standards should not be less stringent. Additionally, 25 Pa. Code §§ 289.121—289.123 define site analysis requirements for geology, soils, and hydrology for Residual Waste Impoundments. The data collection does not negate the potential impacts of constructing a centralized impoundment within 20 inches of soil mottling and potential seasonal high water table. We strongly oppose the allowance of any centralized impoundment within 20 inches of a seasonal high water table.

The use of an artificial underdrain system is likely to affect the adjoining groundwater system beyond the impoundment, including potentially damaging impacts on wetlands and headwater streams through the lowering of the groundwater. Soil moisture conditions are almost certain to be effected by the centralized impoundment construction, and an artificial underdrain system would further exasperate these impacts. Altered groundwater and soil moisture conditions will directly impact established woodland vegetation.

- (4) **Recordkeeping and Reporting:** Centralized impoundments should be subject to the full recordkeeping and reporting requirements of §§ 289.301—289.303, including with respect to the type and amount of material stored in the centralized impoundment, records of activity, transporters and generators, materials rejected and reason, material removed from the centralized impoundment, etc.
- (5) **Site Restoration Plan:** A centralized impoundment site restoration plan should be a required permitting and approval component. This restoration plan should document existing (pre-construction) site conditions with supporting photographs, and include data related to existing soils types, depth of topsoil, organic content and compaction, type and extent of vegetation within a 100-foot perimeter of the disturbed area. Existing topographic conditions should be documented and restored to the 2-foot contour level. A post-construction topographic survey should be required to confirm restoration.
- (6) **Chapter 105 Compliance.** The proposed regulation exempts centralized impoundments of hazard potential 4 and size Category C (up to 40 feet embankment) from the regulatory and permitting requirements of the Chapter 105, Subchapter B, dam safety and waterway management. The proposed regulation would require compliance with the requirements of Chapter 105 only for impoundments of 40 feet or greater in depth (Size Category A or B) or hazard potential 1, 2, or 3. All other centralized impoundments used for oil and gas operations would be required only to obtain a Chapter 78 permit. The Chapter 78 permit does not address most of the important elements of Chapter 105. For example, Subsection § 78.59c(1) proposes that an engineer certify that the impoundment was built in accordance with the construction standards of Chapter 105; however, this certification does not provide the same standard of design, regulatory review, and construction oversight required by Chapter 105, nor does it assure that the certifying engineer is qualified in the area of impoundment design and construction.

Pennsylvania's history of dam failure has resulted in rigorous regulatory requirements for the design, review, and construction of impoundments under Chapter 105. The PADEP staff in the Dam and Waterways section is experienced in the issues related to impoundment design, construction, and maintenance. We do not support by-passing the important requirements of Chapter 105 for oil and gas

impoundments. The proposed Chapter 78 regulations do not guarantee an equivalent level of review to protect public health, safety, and welfare.

Given the EQB's proposal to store regulated substances in centralized impoundments, it is imperative that all requirements of Chapter 105 related to dam safety be applied as a minimum baseline standard for all impoundments. The implications of an impoundment failure or overtopping for a centralized impoundment have all of the same health, safety, and welfare concerns as any other impoundment, with the added concern that the contents of a centralized impoundment can include compounds that are hazardous to both human and ecological health.

The EQB has not provided justification for the proposed Chapter 78 permit process, which seeks to streamline and eliminate key components of the Chapter 105 permit process for most oil and gas impoundments, including all of the Chapter 105 regulations listed below. We request that all centralized impoundments used for oil and gas operation be required to apply for a Chapter 105 permit, or that the key components of the Chapter 105 requirements listed below be included in Chapter 78 for centralized impoundments used for oil and gas operations:

§ 105.81. Permit applications for construction and modification of dams and reservoirs.

(a) ~~In addition to the information required under § § 105.13, 105.13a, 105.13b and 105.15,~~ permit applications under this subchapter for the construction or modification of dams and reservoirs must provide the following information:

(1) Reports and data detailing the conduct and results of investigations and tests necessary to determine the safety, adequacy, and suitability of design, including:

- (i) Data concerning subsoil and rock foundation conditions.
- (ii) Data concerning exploratory pits, drilling, coring and tests to determine seepage rates.
- (iii) Data concerning the strength tests necessary to measure the physical properties and behavior of foundations and embankment materials at the dam or reservoir site.
- (iv) Data concerning the geology of the dam site or reservoir area, indicating possible hazards such as faults, weak seams and joints.
- (v) Data concerning availability and quality of construction materials.
- (vi) A "Dam Stability Report" ~~as required under § 105.97~~ (relating to stability of structures).
- (vii) Other information as may be necessary to determine the safety, adequacy and suitability of the design, including the design calculations for the dam, which shall be made available to the Department on request.

(2) Site plan and cross sectional ~~views required under § 105.13(d)(1)(i) (relating to permit applications information and fees).~~

(3) Construction plans, specifications and design reports to evaluate the safety, adequacy and suitability of the proposed dam, reservoir and appurtenant works in order to determine compliance with this chapter.

(4) A schedule indicating proposed commencement and completion dates for construction.

(5) For projects involving storage of fluids or semifluids other than water, information concerning the chemical content, viscosity and other pertinent physical characteristics of the fluid or semifluid impounded.

- (6) An instrumentation plan including justification and design for the installation of permanent monitoring instruments to measure the performance of the dam. If no instrumentation is considered necessary, justification shall be provided.
- (7) A hydrologic and hydraulic analysis, submitted as a separate report, which includes:
- (i) The size, shape and characteristics of the drainage basin.
 - (ii) Current precipitation data and precipitation distribution information as required by the Department.
 - ~~(iii) Streamflow records.~~
 - (iv) Flood flow records and estimates.
 - (v) An incremental dam breach analysis, storage capacity and reservoir surface area for normal pool and maximum storage elevations.
 - (vi) Other hydrologic and hydraulic determinations necessary for the design and operation of the dam.
- (8) For existing dams, copies of the structure's most recent inspection reports.
- ~~(9) EAP if required under § 105.134 (relating to EAP).~~
- ~~(10) Proof of title or adequate flowage easements for land area below the top of the dam elevation that is subject to inundation.~~
- (11) An Operation and Maintenance Manual for the dam ~~as required under § 105.131 (relating to operation, maintenance and monitoring).~~
- (12) Other information the Department may require.
- (b) The Department may waive specific information requirements of this section in writing, if the Department finds that specific information is not necessary to review the application.

§ 105.92. Foundations.

- (a) The foundation of a dam or reservoir must be stable under all probable conditions.
- (b) In analyzing the stability of the foundation of a proposed or existing dam or reservoir, the applicant shall consider the following factors:
- (1) The seismic forces and liquefaction potential at the site.
 - (2) The shear strength of the foundation.
 - (3) Settlement, subsidence, and carbonate karst solution features, such as sinkholes and solution channels.
 - (4) Seepage potential through the soil and rock components of the foundation.
 - (5) The dispersive characteristics of the soil foundation and borrow areas.

§ 105.93. Design stress.

In the construction of dams and reservoirs, allowable stresses must conform to the current standards accepted by the engineering profession.

§ 105.95. Freeboard.

Sufficient freeboard may be required to prevent overtopping of the dam and to allow for wave and ice action.

§ 105.97. Stability of structures.

(a) Dams must be structurally sound and be constructed of sound and durable materials. The structure must be stable during and at the completion of construction.

(b) As part of the permit application for the construction or modification of a dam, the design engineer shall submit to the Department, under professional seal and certification, a report entitled "Dam Stability Report" which clearly demonstrates to the Department that the requirements of subsection (a) have been satisfied. At a minimum, this report must address the following considerations:

(1) The physical properties of the materials available for construction.

(2) A stability analysis based on the properties of the structure's materials and on the seismic forces and seepage conditions affecting the structure.

(3) The methods of construction.

(4) The conditions of operation of the dam and reservoir.

(c) Earthfill dams must be demonstrated to be stable for the following conditions:

(1) Normal pool with steady-state seepage conditions with a factor of safety of 1.5.

(2) Maximum pool with steady-state seepage conditions with a factor of safety of 1.4.

(3) Sudden drawdown from normal pool conditions with a factor of safety of 1.2.

(4) Normal pool with steady-state seepage conditions under seismic forces produced by the maximum credible earthquake with a factor of safety of 1.1.

(5) Completion of construction with no pool with a factor of safety of 1.3.

(d) Gravity dams must be demonstrated to be stable for the following conditions:

(1) Normal pool with appropriate uplift pressures, ice loads and silt loads with a factor of safety of 2.0.

(2) Maximum pool with appropriate uplift pressures and silt loads with a factor of safety of 1.7.

(3) Normal pool with appropriate uplift pressures and silt loads under seismic forces produced by the maximum credible earthquake with a factor of safety of 1.3.

(e) For gravity dams, the overturning stability is acceptable when the resultant of all forces acting on the dam is located as follows:

(1) Within the middle third of the structure for normal pool conditions.

(2) Within the middle half of the structure for maximum pool conditions.

(3) Within the structure for earthquake conditions.

(f) For gravity dams, the foundation bearing pressures must be less than or equal to the allowable for no pool, normal pool and maximum pool conditions and less than 133% of the allowable for earthquake conditions.

(g) The factors of safety for earthfill dams or gravity dams must be the higher of:

(1) The factors of safety in subsections (c) and (d).

(2) The factors of safety in the most recent Engineering Manuals developed by the United States Army Corps of Engineers relating to stability of dam structures.

(h) The Department may, in its discretion, consider a revised factor of safety for a class of dams or reservoirs when it can be demonstrated that the factor of safety provides for the integrity of the dams or reservoirs and adequately protects life and property.

§ 105.102. Personnel and supervision.

(a) The permittee or owner shall file with the Department, at least 15 days prior to the commencement of construction, a statement setting forth the name and employer, including contact information, of the following:

(1) The professional engineer responsible for oversight and supervision of construction.

(2) Representatives of the professional engineer.

(3) Contractors conducting the work authorized by the permit, Letter of Amendment or Letter of Authorization as required by the Department.

(b) Work must be conducted under the oversight and supervision of a professional engineer. The professional engineer or a representative of the professional engineer shall be on the work site during significant construction activities until the completion of the dam.

§ 105.103. Weather and ground conditions.

(a) No earth or other embankment material may be covered, placed, compacted, or graded when in a frozen condition.

(b) Masonry and concrete may not be placed in freezing weather except under conditions approved by the Department.

§ 105.104. Removal and disposal of vegetation.

(a) Work shall be conducted in a manner to minimize the destruction of or damage to trees and other vegetation on and adjacent to the construction site.

(b) Vegetation cleared and removed from the site shall be disposed of in accordance with applicable laws and regulations.

§ 105.106. Activities and facilities on the construction site.

Activities and facilities on the construction site must be conducted and operated in a manner to avoid pollution of the air and waters of this Commonwealth and in accordance with applicable laws and the provisions of this title.

§ 105.107. Final inspection.

Within 10 days after the completion of work on a dam authorized by the Department, the permittee or owner shall schedule a final project inspection with the Department. The final inspection must include the permittee or owner, the permittee or owner's supervising engineer, and the Department's field representative. Upon conclusion of this final inspection, the Department's field representative will present the permittee or owner with a list of any deficient items, if necessary. A follow-up final inspection may be required by the Department. At the discretion of the Department, the final inspection may be waived for projects authorized by Letter of Amendment or Letter of Authorization.

§ 105.111. Commencement of storage of water, fluid or semifluid.

(a) The permittee shall notify the Department, in writing, at least 7 days in advance of the date proposed for the commencement of storage of water, fluid or semifluid in the reservoir created by the dam for which the permit is issued.

(b) The Department may require that a reservoir filling plan be developed and approved by the Department prior to commencement of storage of water, fluid or semifluid. This plan will provide the acceptable rate of rise of the reservoir and, if necessary, elevations and durations for constant reservoir levels within the filling period. This plan may also require lowering of the reservoir level if the prescribed rate of rise is not controlled or attained. The plan may also require monitoring of instrumentation of the dam.

(c) The Department may require that a representative of the Department be at the site before or during the filling of the reservoir.

(d) The initial storage in the reservoir of new dams and refilling of reservoirs of rehabilitated dams may not commence prior to the submission of the information required in § 105.108 (relating to completion certification and project costs) and the acceptance of the certification, in writing, from the Department.

§ 105.131. Operation maintenance and monitoring.

(a) ~~In addition to the requirements of §§ 105.51—105.54 (relating to operation, maintenance and inspection), the permittee or owner of a dam shall follow the operation and maintenance manual for the dam, and the emergency action plan if required under § 105.134 (relating to EAP), as approved by the Department and shall implement a monitoring plan as required under § 105.81(a)(4) (relating to permit applications for construction and modification of dams and reservoirs).~~

(b) A permittee or owner of a dam or reservoir may not modify or cease implementation of all or part of the approved plans and methods of operation or monitoring without the prior approval of the Department by permit, Letter of Amendment, or Letter of Authorization. ~~The permit will be issued in accordance with § 105.82 (relating to permit applications for operation and maintenance of existing dams and reservoirs).~~ The Letter of Amendment or Letter of Authorization will be issued only after review and approval of necessary engineering calculations, construction plans and construction specifications. If the project impacts wetlands or exceptional value waters, or if the project requires 401 water quality certification, an environmental assessment shall also be submitted to the Department for review and approval ~~under § 105.15 (relating to environmental assessment).~~ Modifications of a dam are subject to the construction requirements and procedures under Subchapters A and B (relating to general provisions; and dams and reservoirs), unless specifically waived by the Department.

(c) The permittee or owner of a dam or reservoir shall operate and maintain the dam in accordance with the authorized plans and specifications. Routine maintenance of the dam and the reservoir's design storage capacity will not require further authorization under this chapter except as relating to drawdown of impounded waters.

§ 105.133. Directed repairs.

The permittee or owner shall immediately take steps that the Department may prescribe as necessary to preserve the structural stability and integrity of the dam and protect health, safety, property and the environment.

§ 105.135. Dam hazard emergencies.

(a) For the purposes of this section, a dam hazard emergency means a condition which the Department, permittee or owner of the dam reasonably finds constitutes an imminent threat to life or property above or below a dam, whether arising from the condition of the dam and appurtenant works or extraordinary natural conditions, affecting the safety and stability of the dam, including flood, earthquake and ice jam.

(b) ~~The emergency procedures and the EAP required under §§ 105.63 and 105.134 (relating to emergency procedures; and EAP)~~ shall be followed by the permittee and owner of a dam or reservoir in the event of an actual or potential dam hazard emergency.

(c) If a dam hazard emergency exists, the permittee or owner of the dam shall immediately notify appropriate emergency management officials identified in the emergency action plan ~~required under §§ 105.63 and 105.134~~ of the existence of the hazard and request the authorities to initiate appropriate action to assure protection of life and property; and the permittee or owner shall immediately take actions as authorized by the Department necessary to prevent dam failure or loss of life or property.

(d) The Department, upon determining that a dam hazard emergency exists, will notify the owner immediately to take actions the Department determines are necessary to prevent dam failure or loss of life or property.

§ 105.136. Unsafe dams.

(a) For purposes of this section, an unsafe dam means a dam which meets one or more of the following criteria:

(1) A dam with deficiencies of such a nature that if not corrected could result in the failure of the dam with subsequent loss of lives or substantial property damage. This determination is based on good engineering judgment or the application of the guidelines established for the National Dam Inspection Program.

(2) A dam classified as unsafe under the National Dam Inspection Program.

(3) A dam declared as unsafe by the Department.

(b) The owner of an unsafe dam shall do the following:

(1) Immediately notify the Department upon receipt of any information indicating the dam is unsafe.

(2) Drain the reservoir as required and approved by the Department ~~and in accordance with § 105.122 (relating to drawdown of impounded waters).~~

(3) Within time limits established by the Department, submit a plan for removal of the dam, a plan for repair of the dam or an application for a permit authorizing modification of the dam under subsection (c).

(4) Following approval of the plan or permit by the Department, undertake and complete actions to remove or repair the dam or implement the modifications to the dam within the time limits set by the Department.

(c) The Department may issue a permit for modification of an unsafe dam, ~~under section 9 of the act (32 P. S. § 693.9)~~, which authorizes the owner of an unsafe dam to modify the dam within the time prescribed in the permit to meet the requirements of the act and this chapter. The permit shall be conditioned upon:

(1) Compliance by the owner of the dam with a prescribed schedule for correction or modification of the unsafe condition within the shortest time period technically feasible and economically achievable.

(2) Implementation by the owner of the dam of measures deemed necessary by the Department to reduce risks to health, safety and the environment pending correction or modification of the unsafe condition, including, but not limited to, special provisions relating to operation, emergency planning, monitoring and warning systems, and development of an alternative source of water supply if the dam serves as a water supply dam.

(d) In determining whether to require removal of an unsafe dam or to permit the owner to modify the dam, the Department will consider whether there is a substantial adverse impact to the public health, safety and the environment which will result from the draining and removal of the dam. If the Department determines that this adverse impact outweighs the danger to public health, safety and the environment resulting from leaving the dam in place, the Department may decide to allow the unsafe dam to remain until it has been modified.

(e) At the discretion of the Department, a public hearing may be held in the affected area prior to the issuance of a permit authorizing modification of an unsafe dam over a period of more than 6 months, to inform affected communities of the risks which may result from allowing the unsafe dam to remain standing or to impound water during the time necessary to complete the modifications.

(f) If the Department finds that conditions upon which the permit, Letter of Amendment, or Letter of Authorization was issued have substantially changed or that the owner does not meet the schedule for modification contained in the permit, Letter of Amendment, or Letter of Authorization, the Department will review the status of the dam. An extension of the time period for completion of a modification may be issued by the Department if the owner has proceeded in good faith with the previous schedule of modification and the requirements of subsections (c) and (d) are met.

(g) Nothing in this section may be construed to limit the power of the Department to take immediate action, prior to public hearing, to do one or more of the following:

(1) Revoke or suspend a permit, Letter of Amendment, or Letter of Authorization when deemed necessary by the Department to protect public health, safety and the environment.

(2) Order correction or abatement of a dam hazard emergency ~~under § 105.135 (relating to dam hazard emergencies)~~

(3) Take another action authorized by law.

§§ 78.15, 78.56, and 78.61 Pits

In our comments on §§ 78.15, 78.56 and 78.61, we opposed the EQB's proposal to use reserve pits, allow land application of drill cuttings, and allow onsite burial of contaminated drill cuttings.

We opposed long-term onsite burial of any drill cuttings contaminated with chemicals, oil, grease, pollutional materials, regulated substances, water based drilling muds that contain chemical additives, oil-based drilling muds, polymer-based drilling muds containing mineral oil lubricants, NORM, mercury, heavy metals, and other chemical additives or toxins. We are particularly concerned that the EQB does not require on-site burial pits to meet the same construction, monitoring, and leak detection standards that would be required of a centralized approved solid waste treatment facility. Nor does the EQB require the operator to test the waste and verify its composition and hazard. For example, the onsite burial methods proposed for drill cuttings are not appropriate for drill cuttings containing NORM or heavy metals or coated with some types of chemicals that would damage the liner.

Drilling waste should be removed from the drilling location and properly disposed of at an approved waste disposal facility capable of handling the quantity and type of waste generated. We recommended the use of closed-loop tank systems to handle and store drilling muds and cuttings, and disposal of this waste at an offsite approved solid waste treatment facility or by deep well injection in an EPA approved well.

If the EQB rejects this recommendation, and permits the continued use of pits, we request that the EQB provide a written scientific and technical analysis justifying the proposal, including:

- (1) A quantitative technical assessment of air, water, soil and human health impact of pit use and proposed disposal methods (onsite burial and land application);
- (2) Data on the historic use of pits in Pennsylvania, including those known to have leaked or overflowed, and quantification of the cumulative adverse impact of these impoundments on air, soil, surface water, groundwater and animal life;
- (3) Data that proves land application of drill cuttings in contact with topohole water, fresh water, or gas is safe. While drill cuttings from above the surface casing seat that have only been in contact with topohole water, freshwater, or gas may not be contaminated if the EQB uses our proposed definition of topohole water and freshwater, we remain concerned that there is no limitation on composition of the drill cuttings itself. For example, drill cuttings could contain NORM or heavy metals. The EQB must consider not only whether the drill cuttings have been contaminated during the drilling process, but whether the drill cuttings themselves contain contaminants;
- (4) Data on historic use of drill cutting land application in Pennsylvania and other states, including an analysis of the frequency, type, and severity of pollution events resulting from land application and a projection of future cumulative impact; and,
- (5) Data on historic long-term onsite burial of drill cuttings in Pennsylvania and other states, including an analysis of the frequency, type, and severity of pollution events resulting from onsite burial and a projection of future cumulative impact.

If, after this analysis is complete, and the EQB finds that use of pits provide a net environmental and human health benefit, we request that the EQB significantly strengthen the regulatory requirements, by including best practices used by the federal government (BLM), other oil and gas producing states, and those we recommend. At a minimum, the following improvements to the proposed regulations should be included:

- (1) **Protection Standard:** All pits shall be designed, constructed, and operated to prevent contamination of fresh water; and protect public health and the environment.¹¹³ The applicant should be required to provide a design, construction and operation plan, signed by a professional engineer that ensures this standard will be met.
- (2) **Pit Location.** No pits should be constructed in sensitive areas or other locations that have heightened potential to result in adverse impacts to human health or the environment.¹¹⁴ Pits may not be located in a mapped floodplain or within 50 feet of the top of bank of any watercourse. Pits should be installed above seasonal groundwater levels. Pit locations should be

¹¹³ N.M. Code, § 19.15.17 (Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps).

¹¹⁴ USDOJ, BLM, *Management of Oil and Gas Exploration and Production Pits* (Nov. 15, 2011).

accurately surveyed, and the location provided to the PADEP for inclusion in a web-based database made available to the public, listing the size, location, and contents of the pit.

- (3) **Pit Separation Distance from Streams and Wetlands.** Pits must not be located within 100 linear feet upstream of any watercourse, wetland, or spring. The applicant shall evaluate the potential flow path and point of discharge from a pit to the nearest downstream water body. The PPC Plan shall document the potential flow path, maximum potential discharge, and proposed emergency response for management of any discharge from a pit to an adjacent or downstream water body.
- (4) **Pit Distance to Seasonal High Water Table:** The requirement that buried pits be only 20 inches above the seasonal high water table gambles with local water quality since Pennsylvania has many shallow groundwater sources. Other states require far greater distances, such as 25 feet in New Mexico.¹¹⁵
- (5) **Meet Chapter 105 Requirements.** All pits should be subject to the PADEP's Chapter 105 regulations, as explained above in the Centralized Impoundment comments.
- (6) **Pit Liner.** All pits should be lined with a synthetic liner that is compatible with the pit contents, resistant to weathering, sunlight, puncturing and tearing.¹¹⁶ Unlined pits are prohibited.¹¹⁷ The liner must be impervious.¹¹⁸ Liner material must be of sufficient thickness and length to withstand expansion and contraction without cracking or being damaged, and withstand settling movements of the underlying earth, and be at least 60 mils thick.¹¹⁹ Two layers of liners should be installed, providing one complete redundant back-up barrier. Pit lining systems shall be designed, constructed installed and maintained in accordance with the manufacturer's specifications and good engineering practices.¹²⁰
- (7) **Pit Leak Detection.** Pits must have a leak detection system that underlies the liner.¹²¹ The leak detection system should monitor a leak between the two layers of liner material.
- (8) **Groundwater Monitoring Systems.** Install groundwater monitoring systems.
- (9) **Fences and Netting.** Pits must be surrounded by fences tall and strong enough to keep out wildlife, and nets or other devices installed to prevent birds from coming in contact with the wastes.¹²²
- (10) **Inspection.** The pit liner and leak detection system must be inspected weekly and a record of the inspection results kept by the operator. The Department should be notified immediately if a leak is detected or the liner is damaged.

¹¹⁵ N.M. Code, § 19.15.17 (Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps).

¹¹⁶ USDOJ, Bureau of Land Management, *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development (The Gold Book)* (4th ed. 2006).

¹¹⁷ N.M. Code, § 19.15.17 (Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps.)

¹¹⁸ Colorado, Rule 904 Pit Lining Requirements and Specifications, <https://cogcc.state.co.us/Announcements/Rule904.pdf>.

¹¹⁹ *Id.*

¹²⁰ *Id.*

¹²¹ USDOJ, BLM, *Onshore Oil and Gas Order No. 7* (1993).

¹²² N.M. Code, § 19.15.17 (Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps).

- (11) **Repair/Removal.** If a leak is detected, pit use must be immediately stopped, the pit removed, and the contamination remediated.
- (12) **Land Application and Burial.** Drill cuttings must be tested to verify that it is uncontaminated prior to land application or burial.¹²³ Drill cuttings containing Naturally Occurring Radioactive Materials, heavy metals, or other regulated substances shall be disposed at an at an offsite approved solid waste treatment facility.
- (13) **Reporting and Recordkeeping.** Quarterly reports should be submitted to the PADEP to verify that the pit continues to meet the PADEP's requirements. Any deficiencies must be immediately reported and remedied.
- (14) **Insurance and Liability.** Require a certificate of pollution insurance of at least \$1,000,000 for each pit. Clarify the operator is strictly liable for any contamination or harm caused by the pit.

§ 78.67 Borrow Pits

If the EQB disagrees with our recommendation to remove the two year extension provision for borrow pit restoration, we request that the Board explain under what circumstances an extension would be prudent and what criteria would be used by the PADEP to make that determination.

Appendix B

Appendix B begins on the following page and is separately paginated.

¹²³ By comparison, Ohio requires contaminated drill cuttings to be sent to a permitted solid waste disposal facility, unless the Ohio EPA approves a beneficial reuse option. Ohio EPA, *Fact Sheet: Drill Cuttings from Oil and Gas Exploration in the Marcellus and Utica Shale Regions of Ohio* (Jan. 2014), http://epa.ohio.gov/Portals/34/document/fact_sheets/Fact%20Sheet%20on%20Drilling%20Muds%20and%20Cuttings%20Final%2010-01-13.pdf.



January 10, 2014

Division of Wetlands, Encroachments, and Training
PADEP Bureau of Waterways Engineering and Wetlands
P.O. Box 8460
Harrisburg, PA 17105-8460

**RE: DRN Comment on Proposal to Modify and Reissue General Permit BWEW-GP-8
(Temporary Crossings and Environmental Testing or Monitoring Activities)**

The Delaware Riverkeeper Network (“DRN”) submit this comment letter in response to the Pennsylvania Department of Environmental Protection’s (the “Department”) announcement of a proposal to modify and reissue General Permit BWEW-GP-8 (Temporary Road Crossings) as General Permit BWEW-GP-8 (Temporary Crossings and Environmental Testing or Monitoring Activities), which allows the construction, operation, maintenance and removal of temporary crossings across regulated waters of this Commonwealth, including wetlands, where no practicable alternatives exist. For the reasons set forth below, DRN request that the PADEP amend the proposed BWEW-GP-8 (“GP-8”) in accordance with the numbered comments articulated below. Until such time that the GP-8 the issues identified below are addressed significant portions of the permit are overly vague, unenforceable, and not sufficiently protective to human health and the environment. The Department has indicated that written comments on the proposed modifications to this General Permit by January 10, 2014.

COMMENT

- 1) Item 2 states that “The Department shall have the discretion, on a case-by-case basis, to deny, revoke or suspend the authorization to use this General Permit for any project



which the Department determines to have a significant effect on the safety and protection of life, health, property or the environment or otherwise would not be adequately regulated by the provisions of this General Permit or determines that the representations made in the application to register are not accurate.”

Comment: Item 2 provides a description of the Department’s discretion to deny, revoke, or suspend authorization to use the GP-8; however, this provision provides no guidance or timeframe for review of potential violations that would result in a denial, revocation, or suspension of the permit. Without such a time frame this provision becomes unenforceable. For example, there needs to be a regulatory review process in place that ensures that once potential violations of terms and conditions of the permit occur as a result of construction activity, the potential violations are reviewed before the construction activity is completed. It is simply not possible to revoke or suspend a permit when the Department waits until all the activity is completed before reviewing the potential violation. This has already occurred in numerous linear infrastructure projects in Pennsylvania in the context of Chapter 105 and 102 permit authorizations (i.e. Tennessee Gas 300 Line Upgrade Project).

- 2) Item 6.C states that this general permit does not apply for temporary service lines that are “trenched or bored.”

Comment: The terms “trenched” and “bored” are not defined in the “Definitions” section of the proposed GP-8, furthermore, there is no guidance anywhere in the



GP-8 that provides an explanation as to how the Department will interpret these

terms. The Department needs to identify what level of ground disturbance triggers the term “trench” or “bored” as those terms are interpreted differently across the regulated community? The GP-8 should make clear that no trenching activities are permitted by the GP-8. Without more specific language identifying what activities are limited to under this item, this section is overly vague.

- 3) Item 6.E. states that this general permit does not apply for temporary service lines that “transmit hazardous or toxic material.”

Comment: The term “hazardous or toxic material” is not defined in the “Definitions” section of the proposed GP-8, furthermore, there is no guidance anywhere in the GP-8 that provides an explanation as to how the Department will interpret this provision. Without more specific language identifying what types of material are “hazardous” or “toxic” this provision is overly vague and unenforceable. Furthermore, the Department should require that the project applicant submit, and make publically available, what constituents each temporary line is carrying.

- 4) Item 6.H-I provide descriptions of activities that are not authorized under the GP-8.

Comment: Section 6.H-I do not provide any prohibitions against adversely impacting Exceptional Value wetlands similar to the protections afforded in 25 Pa. Code 105.18(a) for similar linear activities. The provisions of 105.18(a) should be either expressly written into the proposal or incorporated by reference.



- 5) Item 7.A.2 states “The Department may extend the time, in writing, on a case by case basis not to exceed an additional one (1) year based on the owner's documentation of need.”

Comment: The proposed GP-8 does not define the term “need” in the context of 7.A.2, furthermore, there is no guidance anywhere in the GP-8 that provides an explanation as to how the Department will interpret this provision. Without more specific language identifying how a project applicant can demonstrate “need” the provision is overly vague.

- 6) Item 12.A.4 states “Wetlands shall be identified and delineated in accordance with the 1987 Corps of Engineers Wetlands Delineation Manual and the appropriate Regional Supplements to the Corps of Engineers Wetland Delineation Manual for use in Pennsylvania.”

Comment: Item 12.A.4 should also indicate that the wetlands be classified as either “Exceptional Value” or “Other” consistent with the designations under 25 Pa. Code 105.17. The Corps of Engineers Wetland Delineation Manual does not provide for this specific designation.

- 7) Item 12.A.5 states “Temporary crossings of wetlands shall be avoided if an alternate location is possible. If the crossing of wetlands cannot be avoided, the crossing is permissible if it is located at the narrowest practicable point of the wetland.”

Comment: Item 12.A.4 should describe generally what a project applicant needs to demonstrate in order to prove that a wetlands crossing cannot be avoided. For



example, is it sufficient for the project applicant simply to not own the ROW that

would avoid the wetland? Does the applicant need to at least request permission for

expanding the ROW from the landowner...etc? Does the Department perform a

cost/benefit analysis in making this determination? The Department needs to

provide guidance on how this provision will be interpreted.

- 8) Item 12.A.9 states “Pollution of the waterway, including its floodplains, with harmful chemicals, fuels, oils, greases, bituminous material, acid, and/or other harmful or polluting materials, is prohibited.”

Comment: Item 12.A.9 should include protections from pollution not just for waterways but also for wetlands.

- 9) Item 12.A.13 states that “Temporary crossings of all watercourses, including support structures, shall be inspected by the owner on a regular basis to provide for continued operation and maintenance during the lifetime of the structure.”

Comment: Item 12.A.9 must provide more specific guidance on the interval of time between inspections to satisfy this provision. The term “regular basis” is overly broad and is interpreted differently across the regulated community. Unless modified this item does not provide useful guidance on how to interpret this provision.

- 10) Item 12.G.6 states that “Temporary service line crossings of all watercourses transmitting fresh water which may contain any pollutional materials during the lifetime of the temporary crossing shall be done by a single continuous span of pipe at a minimum from



the outer limit of the floodway across the watercourse to the other side of the floodway outer limit.”

Comment: Item 12.G.6 is inconsistent with item 6.E., which states that this general permit does not apply for temporary service lines that “transmit hazardous or toxic material.” Yet, 12.G.6 indicates that a temporary service line may contain “pollutional materials.” First, there is no definition or guidance in the GP-8 that demonstrates how the Department will interpret the term “pollutional materials.” This term must be specifically defined. Furthermore, to the extent that it is defined, the definition must not conflict with the requirement that no “toxic” or “hazardous” materials are carried in the service line. As proposed, item 12.G.6 and item 6.E cannot be reconciled. The same problem arises in the context of item 12.G.7.

11) Item 12.G.8.a states that Temporary service line crossings of all watercourses transmitting fresh water which may contain any pollutional materials during the lifetime of the temporary crossing shall have an operations and maintenance plan which shall include at a minimum the following: Periodic inspection schedule of the temporary service line.

Comment: Item 12.A.9 must provide more specific guidance on the interval of time between inspections to satisfy this provision. The term “periodic” is overly broad and is interpreted differently across the regulated community. Unless modified this item does not provide useful guidance on how to interpret this provision.



12) Item 12.G.16 states that “No regulated activity may substantially disrupt the movement of those species of aquatic life indigenous to the watercourse, stream or body of water, including those species which normally migrate through the area.”

Comment: The term “substantially disrupt” is not defined in the “Definitions” section of the proposed GP-8, furthermore, there is no guidance anywhere in the GP-8 that provides an explanation as to how the Department will interpret this provision. Without more specific language identifying what types of material are “substantially disrupts” means and how it will be interpreted by the Department this provision is overly vague and unenforceable.

13) GP-8, generally.

Comment: Under what conditions may a project applicant fell trees for a ROW for a temporary service line? How wide may a ROW be for a temporary service line? What are the restoration and mitigation requirements for such activities?

CONCLUSION

Until such time that the items above are addressed significant sections of the proposed GP-8 permit are overly vague, unenforceable, and not sufficiently protective to human health and the environment. DRN respectfully requests that these changes be made before the permit is issued.

Dated: January 10, 2014

By: /s/ Maya K. van Rossum

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Aaron Stemplewicz, Staff Attorney
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EXHIBIT 2

Expert Resumes

Susan Harvey, Harvey Consulting, LLC

Michele Adams, Meliora Design

Kevin Heatley

Briana Mordick, Natural Resources Defense Council

HARVEY CONSULTING, LLC.

Susan Harvey has over 26 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and supervisory positions at both Arco and BP including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed and managed both on and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning.

Ms. Harvey has worked on oil and gas projects in Alaska, New York, Pennsylvania, Ohio, West Virginia, Texas, New Mexico, and Oklahoma, as well as in Canada, Australia, Russia, Greenland, and Norway. Ms. Harvey has authored numerous technical reports related to oil and gas project construction, operation, and abandonment, including best practices for oil and gas well construction, air and water pollution abatement design and execution, environmental assessments of oil and gas projects, and oil spill prevention and response planning. Ms. Harvey holds a Master of Science in Environmental Engineering and a Bachelors of Science in Petroleum Engineering.

Education Summary:

Environmental Engineering
Masters of Science
University of Alaska Anchorage

Petroleum Engineering
Bachelor of Science
University of Alaska Fairbanks

Consulting Services:

- Oil and gas, environmental, regulatory compliance advice and training
- Oil spill prevention and response planning
- Air pollution assessment and control

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Co-owner
2002-2007	University of Alaska at Anchorage Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation Environmental Supervisory Position
1996-1999	Arco Alaska Inc. Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc. Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company (<i>purchased by BP in 1989</i>), Engineering Position
1985-1986	Conoco, Production Engineer and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

Employment Detail:

- 2002-Current** **Harvey Consulting, LLC.**
Owner of consulting business providing oil and gas, environmental, regulatory compliance and training to clients.
- 2005-Current** **Harvey Fishing, LLC.**
Co-owner and operator of a commercial salmon fishing business in Prince William Sound Alaska.
- 2002-2007** **University of Alaska at Anchorage**
Environmental Engineering Graduate Level Program, Adjunct Professor Air Pollution Control.
- 1999-2002** **State of Alaska, Department of Environmental Conservation**
Environmental Supervisory Position
Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.
- 1996-1999** **Arco Alaska Inc.**
Engineering and Supervisory Positions held
Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120,000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America. Responsible for six concurrently operating drilling and workover rigs.
- Prudhoe Bay Satellite Exploration Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting. Responsible for two appraisal drilling rigs.
- Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.
- 1989-1996** **BP Exploration (Alaska), Inc.**
Environmental, Engineering, and Supervisory Positions held
Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering, technical and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects.
- Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved technical, legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

1987-1989

Standard Oil Production Company, Production Engineer

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

Engineering Internship, Barry Waterflood Oklahoma City OK.

1986

Conoco, Production Engineer

Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986

New Mexico Institute of Mining and Technology

Petroleum Research & Recovery Center

Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.

Harvey Consulting, LLC, Major Projects and Publications

Polar Tankers, Inc., Prince William Sound Oil Spill Response Exercise, October 7-9, 2013, Evaluation Report prepared for Prince William Sound Regional Citizens' Advisory Council, 2014.

Arctic Outer Continental Shelf Standards, Recommendations for Arctic-Specific Oil and Gas Exploration, Development and Production, and Oil Spill Prevention and Response Requirements for the Outer Continental Shelf of the United States, prepared for The Pew Charitable Trusts, 2013.

Rezoning and Master Plan Permit applications, standard operating procedures, and model stipulations prepared for North Slope Borough, 2012-2014.

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Belize Offshore Oil Concessions Lawsuit, expert report for Anderson & Kreiger, LLP, 2013.

Greenland Relief Well Requirements Report, for Oceans North Canada, 2013.

Stockport Mountain Corporation, LLC vs. Norcross Wildlife Foundation, Inc., In the United States District Court for the Middle District of Pennsylvania, expert witness for Norcross Wildlife Foundation, Inc., 2011-2013.

Oil and Gas New Source Performance Standard Petition for Reconsideration, air pollution emission calculation expert declaration, prepared for Sierra Club, 2012-2013.

Valdez Marine Terminal Oil Discharge Prevention and Contingency Plan review and recommendations, prepared for Prince William Sound Regional Citizens Advisory Council, 2013.

Resource Development Land Use Permitting Program, technical and regulatory advice to Aleutians East Borough, 2013-2014.

Proposed Revisions to the New York Code of Rules and Regulations Best Technology and Practice technical assistance to Natural Resources Defense Council (NRDC), 2013.

Project Review of Cairn Energy's 2011 Offshore Drilling in West Greenland, prepared for Inupiat Circumpolar Council and Oceans North Canada, 2013.

Hydraulic Fracturing and Workover Operation Regulatory Improvement Recommendations for Alaska, technical assistance to The Wilderness Society, 2013.

Crude Oil Storage Tank 5, American Petroleum Institute Tank Inspection Record Review, Audit and Corrosion Calculations, report prepared for Prince William Sound Regional Citizens Advisory Council, 2012.

Inspector Standard Operating Procedures Manual and Inspection Forms, prepared for North Slope Borough, 2012-2013.

ConocoPhillips Inc., Chukchi Sea Exploration Plan and Oil Discharge Prevention and Contingency Plan, technical review for North Slope Borough, 2011-2012.

Model Regulatory Framework for Hydraulically Fractured Wells, draft regulations for Gas Industry Workgroup Participants and Environmental Defense Fund, 2011-2012.

Valdez Marine Terminal Contaminated Sites Report, prepared for the Prince William Sound Regional Citizens Advisory Council, 2012.

Greenland Offshore Oil and Gas Mitigation Measures, prepared for Ducks Unlimited, on behalf of the Inupiat Circumpolar Council, 2012.

Greenland Offshore Oil and Gas Industry, Government and ICC Workshop, Nuuk Greenland, provided technical advice for Ducks Unlimited, on behalf of the Inupiat Circumpolar Council, 2012.

Land Use Complaint Form, prepared for North Slope Borough, 2012.

Endicott and Badami Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for the North Slope Borough, 2012.

NPDES Arctic General Permits for Beaufort and Chukchi Sea Exploration, technical analysis and recommendations prepared for the North Slope Borough, 2012.

Environmental Law Foundation vs. Southern California Gas Company, Superior Court of the State of California County of Los Angeles, Central Civil West District, expert witness for Environmental Law Foundation, 2011 and 2012.

Oil & Gas Exploration and Production Operations, permit applications, standard operating procedures, and model stipulations prepared for North Slope Borough, 2012.

Revised 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 Proposed Revisions to the New York Code of Rules and Regulations Best Technology and Practice Recommendations Report to Natural Resources Defense Council (NRDC), 2012.

Repsol Exploration Drilling Program, Colville River Delta, technical review and report for North Slope Borough, 2011-2012.

TRI Petition, technical analysis of metals in drilling muds, hydraulic fracture chemicals and acid stimulation chemicals, prepared for Sierra Club, 2012.

Pioneer Nuna Oil and Gas Facility Construction Master Plan and Rezoning Project, technical review and report for North Slope Borough, 2011-2012.

Offshore Oil & Gas Drilling, Greenland, technical advice to Oceans North and Inuit Circumpolar Council (ICC) Greenland, 2011-2012.

Environmental Defense Foundation, technical advice on oil and gas well construction and air pollution control at oil and gas operations, 2011-2012.

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Southern California Gas Northeast Natural Energy, LLC. and Enrout Properties, LLC vs. The City of Morgantown, West Virginia, Monongalia County Circuit Court, West Virginia, expert for The City of Morgantown, 2011.

ConocoPhillips Alaska Inc., CD5 Niglik Channel Pipeline Crossing, technical advice for North Slope Borough, 2011.

Arctic Oil and Gas Project, technical advice to Pew Charitable Trust, 2010-2013.

Alaska Oil and Gas Conservation Commission Proposed Regulation Changes, Title 20, Chapter 25, Alaska Administrative Code Arctic Drilling, technical review and comments prepared for North Slope Borough, 2011.

Shell Kulluk Drilling Rig and Nanuq Vessel On-Site technical review, Report to North Slope Borough, 2011.

Review of Reduced Emission Completion Estimates Used by EPA and Critiques of EPA's Estimates Completed by IHS CERA, URS (for ANGA) and API, report to Sierra Club, 2012.

Nikaitchuq Oil and Gas Development Project, technical advice to North Slope Borough, 2011.

Valdez Marine Terminal, Oil Spill Prevention Audit, report prepared for Prince William Sound Regional Citizens Advisory Council, 2011.

Great Bear Petroleum Exploration Oil Spill Prevention and Response Plan, technical review and comments prepared for North Slope Borough, 2011.

Recommendations to Improve the December 9, 2010 Delaware River Basin Commission (DRBC) Proposed Natural Gas Development Regulations, report prepared for Delaware Riverkeeper Network, 2011.

Oooguruk Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Crude Oil Storage Tank 14, Valdez Marine Terminal, integrity audit report prepared for Prince William Sound Regional Citizens Advisory Council, 2011.

Trans-Alaska Pipeline Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for North Slope Borough, 2011

Carin Offshore Greenland Drilling Program, technical review for WWF-Canada, 2011.

Shell Beaufort Sea Exploration Plan, technical support to North Slope Borough, 2007-2012.

Canadian National Energy Board, Offshore Drilling Review, technical support to WWF-Canada, 2011.

Joint Industry Program (JIP) - Oil in Ice Review of 2008-2009 Research & Development Program Reports, report to WWF, 2011.

Shell Chukchi Sea Exploration Plan, technical advice to North Slope Borough, 2010-2012.

SINTEF Behavior of Oil and Other Hazardous and Noxious Substances (HNS) spilled in Arctic Waters (BoHaSA) Report, technical review and advice to WWF, 2011.

BP, Milne Point Oil & Gas Project, technical review and advice to North Slope Borough, 2011

Canadian National Energy Board, Offshore Drilling Review, technical support to WWF-Canada, 2011.

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Valdez Marine Terminal Oil Spill Prevention and Response, technical support Prince William Sound Regional Citizens Advisory Council, 2002-2013.

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Michele C. Adams, P.E. LEED AP

President and Founder



Relevant Experience

Ms. Adams is the President and founder of Meliora Design. For more than 28 years, her work has encompassed environmentally sensitive site design and sustainable water resources engineering. Building on a multi-disciplinary approach, her work includes both master planning and design for campuses, cities, urban restoration projects, commercial, industrial and residential installations, public facilities, and environmental education centers. In all her work, Ms. Adams seeks to combine sound engineering science with an understanding of natural systems. She is a frequent lecturer and educator on the topics of water and sustainability, and has provided technical expertise to clients ranging from watershed advocacy organizations to corporations. Ms. Adams was one of the principle authors of the Pennsylvania Stormwater Manual, and serves on the U.S. Green Building Council's Technical Advisory Group for Sustainable Sites, and American Rivers Science and Technical Advisory Committee. She frequently serves as an expert witness with regards to stormwater and surface water quality issues. Several recent and current projects in which Ms. Adams is engaged include the following:

Stroud Water Research Center Environmental Education Center, Academy of Natural Sciences, Avondale, PA: For one of the nation's premier water research and education facilities, sustainable site design engineering related to "living within the water budget". Design elements include rain gardens, water cisterns and reuse, a green roof, permitting for a wetlands wastewater system, and riparian buffers. The site is quantified to maintain a "water balance".

Low Impact Design Manual and Stormwater Program, Chattanooga, TN: For the City of Chattanooga, which is required by permit to implement Low Impact Development to address the problems of impaired streams, developing a Manual, stormwater permit review/approval process, and supporting zoning and planning materials to successfully implement a "green infrastructure" approach in all new and redevelopment projects.

U.S. Botanic Garden Bartholdi Park, Washington, D.C.: Design of stormwater management measures in the landscape and along streetscapes to serve as demonstration sites, as well as to comply with the new Federal Regulations for stormwater management as part of Section 438 of the Energy Independence and Security Act. The project is a Sustainable Sites Initiative pilot project.

High Performance Landscapes, New York City Parks and Recreation: Ms. Adams served as one of five authors in development of the New York City's *High Performance Landscapes* document, specifically addressing the water issues within the document. This publication is the third in a series that began with *High Performance Buildings*, and is providing the framework for sustainability in NYC parks and public spaces.

Drexel University Stormwater Master Plan: Development of a campus-wide Stormwater Master Plan which will serve as a blueprint to facilitate future development outlined in the Master Plan, as well as addressing present stormwater concerns. The Plan will integrate sustainable stormwater measures into the existing campus layout and landscape, while establishing stormwater policy to guide future development.

North 3rd Street Corridor Sustainable Affordable Housing Plan, Philadelphia: With Pennsylvania Horticultural Society, developed guidelines and tools for sustainable affordable urban housing, including stormwater and water reuse measures to reduce combined sewer overflows and meet City of Philadelphia "green infrastructure" requirements.

Special Qualifications

Twenty-eight years of experience in civil and water resources engineering.

Sustainable site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, tree trenches, vegetated roofs, etc) and alternative wastewater treatment systems (wetlands, drip irrigation, recirculating filters). Design for projects seeking LEED certification.

Watershed studies, computer modeling, stormwater sampling, stream flow monitoring, NPDES permit applications, mixing zone analyses, pollution prevention plans.

Professional Credentials

Bachelor of Science Civil Engineering
Pennsylvania State University, State College, PA, 1984

Graduate Coursework Water Resource Engineering
Villanova University, PA 1997-2001

Registered Professional Engineer in Delaware, Pennsylvania, Virginia, Maryland, New York

LEED Accredited Professional

Green Streets Design and Philadelphia Green Streets Manual: Led a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a “complete” street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. Currently incorporating the design guidelines for the stormwater components into the City’s “Green Streets Manual”. Several streetscapes and intersections have been constructed to include stormwater management along with pedestrian access, multiple users, and increased green space.

Technical Review of Philadelphia Green City, Clean Waters Plan: Ms. Adams and Dr. Robert Traver of Villanova University were engaged to provide an independent technical review and recommendations for the City of Philadelphia Green City, Clean Waters program. Various technical and policy recommendations were incorporated into the plan and the final permit.

Review and Comments DNREC Draft Stormwater Regulation: For a coalition of environmental advocacy and conservation organizations, Ms. Adams was engaged to review and provide comments on the DNREC’s 2012 Proposed 5101 Sediment and Stormwater Regulations.

Peer Review for EPA Stormwater Program: Ms. Adams has served as a technical peer reviewer for various technical documents and material in support of EPA’s evolving stormwater policies.

Three Groves Ecovillage: Site Design for a zero-energy residential community that includes housing units, a community food garden, community building, and a natural pool. Stormwater measures include porous pavements, rain gardens, stream buffers, and re-use, and wastewater will be discharged to a land application system.

Greening and Stormwater Retrofits for Urban Schoolyards, Parks, and Streets in Philadelphia: For multiple locations in the City of Philadelphia, “green infrastructure” retrofits to capture stormwater and improve communities through stormwater tree trenches, bioretention gardens, porous pavements and playgrounds, reuse cisterns, and other measures. Built projects include three schools, two recreation centers, several parks and urban food gardens, and multiple streetscapes and public sites. Over twenty impervious acres have been “captured”, and two projects are featured at <http://vimeo.com/13844085> and <http://vimeo.com/15231400>.

Green Infrastructure Planning, City of Wilmington, DE: Evaluation and identification of potential “green infrastructure” locations within urban neighborhoods to capture stormwater and improve neighborhood conditions with increased green space, tree canopy, and recreational facilities. The project goal is to capture the stormwater from thirty impervious acres.

Hamilton Family Children’s Zoo at the Philadelphia Zoo: Design of an integrated water system, including elements that provide educational opportunities, including green roofs, porous paths, rain gardens, and cisterns for toilet needs.

Wiki Watershed “Model My Watershed”: For Stroud Water Research Center under funding from the National Science Foundation, technical support for the development of an educational watershed modeling tool for students and watershed groups. The tool allows students to evaluate the impacts of development on the water “balance” and watershed health. Students can then

Professional Employment History

2007- Present
President and Founder
Meliora Environmental
Design

1997- 2007
Principal Engineer
Cahill Associates, West
Chester, PA

1990-1997
Project Manager
Roy F. Weston, Inc., West
Chester, PA

1984-1990
Project Engineer
Cahill Associates, West
Chester, PA

Professional Memberships

U.S. Green Building
Council – Sustainable Sites
Technical Advisory Group
(SS TAG) (former member)

American Rivers Science
and Technical Advisory
Committee Member
(STAC)

Member, American
Society of Civil Engineers,
Environmental Water
Resources Institute

Member, American Water
Resources Association

Guest Lecturer; University
of Pennsylvania;
Philadelphia University,
Penn State, Temple
University, Drexel University

Former East Vincent
Planning Commission
Chairman

Panther Hollow Watershed Restoration Pittsburgh: For an ultra-urban watershed, development of a restoration plan to restore stream baseflow and health. Efforts include hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of pilot projects to capture street runoff and restore impacted landscapes.

For ten years prior to forming Meliora (1997 – 2007), Ms. Adams was a Principal Engineer with Cahill Associates, where she successfully directed and participated in all aspects of a number of projects.

Pennsylvania Stormwater Best Management Practices Manual, Pennsylvania DEP, co-author of State Manual describing structural and non-structural BMPs, Control Guidelines, calculation methodologies, and specifications, including a volume-based approach to stormwater.

Northern Federation of Communities Sustainable Water Resource Plan, PA – development of a watershed plan to evaluate all anticipated aspects of water, wastewater, and stormwater impacts from planned growth, and to prevent adverse impacts to groundwater supply and stream health. A GIS based tool was developed to identify areas that could support growth, and areas that should be protected by zoning.

Environmental and Stormwater Master Plan, UNC Chapel Hill, NC, Environmental master planning for sustainable water approach to address large university expansion plan. Recognized by Sierra Club as a “Top Ten Building Better II” project.

Grey Towers National Monument, National Forest Service, Sustainable site design for historic gardens, including various stormwater measures integrated with on-site water and wastewater systems.

Western Pennsylvania Girls Scouts Wastewater System, West Virginia – For new Camp and Nature Center located in mountains, development of a zero-energy, low-disturbance wastewater system for facility wastewater needs, and a supporting water re-use system.

Washington National Cathedral, D.C., Restorative stormwater measures for Cathedral site and woods, including various infiltration measures (at source of runoff), infiltration for road system, channel stabilization, etc. and infiltration trenches integrated into new outdoor amphitheater.

Mill Creek Community Garden and Clark Park Urban Stormwater Projects, Philadelphia, PA, Design of urban stormwater systems that collect runoff from City streets and infiltrate/manage water in urban green spaces such as community gardens and new basketball courts.

Cusano Center at John Heinz National Wildlife Refuge, Tinicum, PA, Sustainable site design for educational center, including various stormwater elements and permitting for a Living Machine wastewater system.

Springbrook Low Impact Development, Lebonon County, PA, Design of full LID stormwater system for 247 residential units in karst area, including over 120 individual stormwater systems (vegetated infiltration beds, infiltration trenches, rain gardens, porous pavements, etc.).

Ford Rouge Sustainable Stormwater Management, Dearborn, MI, Stormwater planning and design for major industrial facility re-development (Porous pavement, bioretention swales, vegetated systems).

From 1990 through 1997, Ms. Adams was a Project Engineer and Project Manager at Roy F. Weston, Inc. Concept Engineering Division.

Stormwater and Wastewater Analysis, Design and Permitting Ms. Adams developed and implemented stormwater management and sampling programs at over fifty industrial, commercial, and military facilities throughout the United States. For a variety of watershed studies, Ms. Adams conducted hydrologic and hydraulic modeling using various mathematical computer models, including EPA SWMM, and COE HEC models. Ms. Adams performed floodway analysis studies on a number of rivers and

Expert Testimony within Past Five Years

- 2013** **Citizen's for Pennsylvania Future vs. City of Pittsburgh;** Pennsylvania Environmental Hearing Board mediation regarding stormwater management and MS4 requirements.
- 2013** **Delaware Riverkeeper Network vs Tennessee Pipeline;** Pennsylvania Environmental Hearing Board. Expert witness on behalf of Delaware Riverkeeper Network on issues related to pipeline impacts on water quality, stormwater, erosion and sediment control, and soil compaction.
- 2011** **Blue Mountain Preservation Association vs Alpine Development Rose Resorts;** Pennsylvania Environmental Hearing Board. Expert witness on behalf of BMPA on issues related to stormwater management and water quality.
- 2010** **Koziell and Perrini vs Madison Township; Lackawanna Court of Common Pleas;** Expert witness on adverse stormwater impacts of road improvements.
- June 2010** **West Vincent Zoning Hearing Board; Flather Property;** Testimony on behalf of Green Valleys Association and PennFuture related to impacts of **water** quality on variance request for stream buffer and wetland setback requirements.
- Jan 2010** **West Pikeland Zoning Hearing Board;** Testimony on behalf of Green Valley Association related to impacts of water quality and stream health on variance requests to environmental ordinances.
- 2009/2011** **Tim and Jamie Lake vs The Hankin Group;** Court of Common Pleas Chester County; Expert witness on stormwater design and flooding.
- 2008-2009** **Crum Creek Neighbors vs DEP, et al;** Pennsylvania Environmental hearing Board; Expert witness on stormwater design review and impacts on flooding and water quality.
- 2008** **Glenhardie Condominium vs. Realen Associates; Appeal of NPDES Post-construction Stormwater Management Permit;** Expert witness on behalf of Glenhardie related to stormwater design and flooding. Permit was withdrawn.

Expert Analysis and Comment within Past Five Years

- 2013** **City of Philadelphia Longterm Control Plan, Monitoring Plan;** on behalf of Natural Resources Defense Council, review and development of recommendations for LTCP Monitoring Plan in compliance with PaDEP permit and EPA agreement.
- 2012** **New York State Draft SGEIS and Draft SPDES Permit for High Volume Hydraulic Fracturing;** on behalf of Natural Resources Defense Council, review and technical recommendations related to hydraulic fracturing.
- 2011** **Delaware River Basin Commission Oil Proposed Oil and Gas and Hydraulic Fracturing Regulations;** on behalf of Delaware Riverkeeper Network, technical review and analysis of DRBC Draft regulations for Hearing.
- 2011** **Pennsylvania Environmental Regulations for Oil and Gas Industry and Hydraulic Fracturing;** on behalf of Delaware Riverkeeper Network, review, comment and testimony related to Pennsylvania water quality impacts and regulatory needs.
- 2009/2012** **Pennsylvania Turnpike Expansion Project;** on behalf on National Park Service Valley Forge National Park and Valley Creek Coalition. Expert services related to review and comment of stormwater design and impacts on water quality and stream conditions.
- 2009/2012** **City of Philadelphia Longterm Control Plan;** on behalf of Natural Resources Defense Council and PennFuture; review of technical reports, policy documents, and draft permit conditions on issues related to stormwater management, water quality, stream health, and compliance with Clean Water Act and EPA Longterm Control Policy.
- 2010** **City of Chattanooga MS4 Permit;** For City of Chattanooga, providing technical guidance for incorporation of stormwater measures to address and restore impaired streams and meet TMDL requirements. Training sessions for municipal officials and program development.

Publications

- Design for Flooding: Architecture, Landscape, and Urban Design for Resilience to Climate Change;** By Donald Watson and Michele Adams; Wiley Publishing, Hardcover Nov 2011.
- Park Design for the 21st Century: High Performance Landscape Guidelines;** New York City Parks Department and NYC Design Trust; Nov 2010.
- Porous Asphalt Pavement: 20 Years and Still Working,** Michele Adams, Published in Stormwater Magazine May/June 2003.

Kevin Heatley, LEED AP
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Hughesville, Pa. 17737
(570) 419-0310

Professional Experience – Private Sector

2010 - 2014 Biohabitats, Inc., Baltimore, MD, Senior Scientist
2006 - 2010 Biohabitats Invasive Species Management, Inc., ISM Vice President
2005 - 2006 Penn State College of Technology, Williamsport, PA, Substitute Instructor, Natural Resource Management Department
2005 - 2006 Invasive Plant Control, Inc., Nashville, TN, Director of Development Northeast Region
1997 – 2005 ACRT Inc., Akron, OH, Senior Forester/Regional Manager
1984 – 1994 Bartlett Tree Experts, Lancaster, PA, Area Manager/Arboricultural Consultant

Education

Masters Environmental Pollution Control, Penn State University, Harrisburg, PA, 2006
B.S., Natural Resource Management, Cook College, Rutgers University, New Brunswick, New Jersey 1982

Professional Registration

Certified Arborist #PD-0029, (over 20 years certified)
LEED Accredited Professional for New Construction (USGBC), 2009

Professional Private Sector Experience

Over 25 years of experience in the environmental and land management sector with an extensive background in sustainable development, ecosystem characterization, integrated vegetation management, invasive species suppression and community-based forestry. As a senior ecologist at Biohabitats, I was technical lead and had primary responsibility for the logistical oversight of ecological restoration and sustainability projects across the continental United States. I coordinated and served as the project manager for Biohabitats twenty-five million dollar Eastern States Revegetation IDIQ contract with the National Park Service. This project involved extensive budget preparation, permitting, stakeholder engagement, specifications development, subcontractor recruitment and coordination, along with implementation oversight at NPS locations across the eastern United States. In addition to the NPS operations, my work focused upon the urban/rural interface and on incorporating green infrastructure into sustainable land use planning and management. I possess specialized expertise with respect to conservation and invasion biology, having designed the first fully integrated invasive species treatment prioritization model in the United States for Fairfax County, Va. At ACRT I successfully imbedded resource valuation modeling into strategic and budgetary management plans for a variety of land management entities and major municipalities across the United States. I was also instrumental in providing the conceptual design for a leading GIS-based vegetation management software system.

During my professional career I have lectured on a variety of natural resource topics throughout the United States and the Caribbean. I have a proven ability to engage a diverse audience and have conducted webinars, along with facilitating, and participating in, stakeholder engagement and strategic planning sessions.

Representative Project Experience

NPS Revegetation Eastern States IDIQ, Eastern US. I successfully served as the Biohabitats project manager on a 25 million dollar National Park Service Revegetation IDIQ contract. I coordinated and lead project planning and technical assistance services on a wide variety of ecological restoration task orders including revegetation, conservation planning, invasive species control, plant procurement, seeding, plant protection efforts, marsh restoration, and site characterization.

Burgundy Farm Country Day School Ecological Site Assessment, Alexandria, VA. As project manager at Biohabitats Inc., I performed an ecological assessment of the campus and developed recommendations for the sustainable use and conservation of the school's assets. Proactive identification of both ecological assets and landscape challenges enabled the School to cost-effectively integrate site ecology into the master planning process.

Fairfax County Parks Invasive Plant Site Prioritization Model, Fairfax County, VA. As Senior Vice president of Biohabitats ISM, I developed a comprehensive response strategy and site treatment prioritization model as a decision-making tool to be used by the Park Authority to rank the relative value of different sites within their approximately 24,000-acre park system. Based on the principle of "protect the best first" the model shifted the focus in the parks system away from "acres treated" towards "acres restored," allowing the County to maximize the return on its investment in invasive plant control by assuring that treatment sites reflect both the core ecological and cultural values that exist. Project involved extensive stakeholder engagement and education.

Lehigh University, Bethlehem PA. Desiring to more fully understand potential atmospheric carbon mitigation opportunities on the college campus, Lehigh University contracted with Biohabitats to undertake an analysis of the direct sequestration and avoided emissions associated with the schools landscape tree cover. Utilizing US Forest Service models, I performed a comprehensive inventory of 600 acres of naturalized forest and over 220 landscape trees. Information gathered was integrated into strategic recommendations for enhancing this forest benefit and achieving a sustainable level of forest canopy.

Woodland Restoration of Episcopal High School Alexandria, Alexandria, VA. Driven by a desire to integrate a 35 acre woodland resource into the fabric of campus life, the Episcopal High School of Alexandria, Va. contracted with Biohabitats ISM to develop a sustainable campus forest management plan and implement invasive species suppression. As project manager I directed the campus ecosystem characterization, functional benefits modeling, and stakeholder vision sessions. Botanical communities on campus were defined and their respective ecosystem services, in the form of air pollutant interception and carbon sequestration, quantified. Key action items and funding sources were developed as a function of the phased implementation plan.

Episcopal High School, Baton Rouge, LA. Recognizing the need to integrate sustainable design principles into future development on their 40 acre campus, the Episcopal High School contracted with Biohabitats (in conjunction with NK Architects) to develop a new Master Plan for the school. I coordinated Biohabitats participation and involvement in this interactive process. I was directly responsible for developing recommendations and strategies addressing stormwater retrofitting, green infrastructure expansion, and natural capital valuation.

Professional Associations

Society of American Foresters
International Society of Arboriculture

Selected Publications, Technical Reports & Presentations

Smart & Sustainable Campuses Conference, Baltimore, MD, March 2014

Greater Everglades Ecosystem Restoration Conference, Naples, FL, July 2010

Land Trust Alliance Annual Rally, Portland, OR, November 2009

Professional Grounds Management Society, Louisville, KY, October 2009

Mid-Atlantic Exotic Pest & Plant Council, Johnstown, PA, July 2009

Society of American Foresters, Western New York Chapter, April 2008

11th Caribbean Urban Forestry Conference, St. Croix, Virgin Islands, June 2006

St. Croix Environmental Association Tree Conservation Workshop, St. Croix, Virgin Islands, June 2006

Southeast Exotic Pest & Plant Council Annual Meeting, Raleigh, NC, May 2006

Association for Zoological Horticulture, *Tree Preservation Specifications Manual* (Industry Standard), 2005

Penn State Invasive Pest, Plants & Weeds Workshop, Luzerne County, PA, October 2005.

BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL STAFF SCIENTIST

September 2010 – Present

Technical advisor on issues related to oil and natural gas extraction and geologic sequestration of carbon dioxide. Provides scientific expertise and analysis in support of advocacy efforts. Identifies regulatory solutions and industry best practices to address the environmental impacts of oil and natural gas extraction. Engages with and serves as a liaison to the scientific community.

ANADARKO PETROLEUM CORPORATION

January 2005 – September 2010

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – September 2010) **Senior Geologist & Team Lead**

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO₂ Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)

Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO₂
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO₂ flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)

Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

ANADARKO PETROLEUM CORPORATION GEOSCIENCE INTERN

The Woodlands, Texas
September 2004 - November 2004

Evaluated the Baxter shale in active Wyoming oil and gas fields for shale-gas production potential.

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL MASTER OF SCIENCE, GEOLOGICAL SCIENCES

Chapel Hill, North Carolina
September 2002 – May 2005

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY BACHELOR OF ARTS, EARTH SCIENCE

Boston, Massachusetts
September 1998 – May 2002

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

BRIANA E. MORDICK

PUBLICATIONS

Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: Contributions to Mineralogy and Petrology, v. 152, no. 1, p. 111-124.

SELECTED PRESENTATIONS

- October 19, 2010:
 - Forum: National Research Council of the National Academies, Board on Earth Sciences and Resources, Committee on Earth Resources
 - Meeting Title: “Meeting Our Nation’s Natural Resource Needs: Balancing Risks and Rewards”
 - Presentation Title: “Environmental Impacts of Oil and Gas Production”
- March 11, 2011:
 - Forum: EPA Hydraulic Fracturing Study Technical Workshop
 - Meeting Title: Well Construction and Operations
 - Presentation & Abstract Title: “Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned”
- September 27, 2011:
 - Forum: University of Wyoming Hydraulic Fracturing Forum
 - Meeting Title: Hydraulic Fracturing, A Wyoming Energy Forum
 - Presentation Title: Hydraulic Fracturing Best Practices: Mitigating Environmental Concerns
- April 30, 2012
 - Forum: Eurasia Group Workshop
 - Meeting Title: US Unconventional Oil and Gas Resources: National Security Implications
 - Panel: Obstacles to US unconventional oil and gas development
 - Presentation Title: Environmental Impacts of Oil and Natural Gas Production
- June 25, 2012
 - Forum: NRDC Workshop on Shale Gas in China
 - Meeting Title: Workshop on Best Practices for Shale Gas Development in China: Policies and Technologies to Minimize Environmental Impacts
 - Presentation Titles: US Shale Gas Development Technologies and Experience; Best Practices for Minimizing Water Use and Pollution from Shale Gas Development
- March 15, 2013
 - Forum: Woodrow Wilson Center
 - Meeting Title: Shale Gas Revolution in China: Game Changer for Coal?
 - Presentation Title: Shale Gas Revolution in China: Game Changer for Coal?
- October 4, 2013
 - Forum: American Chemical Society, Western Regional Meeting
 - Meeting Title: Hydraulic Fracturing in California: Environmental Issues with the Largest Shale Oil Formation in the U.S.
 - Panel Discussion