Delaware River Basin Commission (DRBC) Consolidated Administrative Hearing on Grandfathered Exploration Wells

Report to:

Delaware Riverkeeper Network
and
Damascus Citizens for Sustainability, Inc.

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Susan L. Harvey

Susan L. Harvey, Owner

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A. Executive Summary

This report responds to the Delaware Riverkeeper Network's (DRN) and Damascus Citizens for Sustainability's (DCS) request to provide expert review and opinion on the Delaware River Basin Commission's (DRBC) decision to exclude 11 Pennsylvania state permitted wells in Wayne County from DRBC review of exploration wells under its June 14, 2010 and July 23, 2010 Supplemental Determinations. The findings contained in this report are based on the material provided by DRN and DCS, as shown in the attached exhibits. The opinions stated here are stated to a reasonable degree of scientific and professional certainty.

This report provides my opinion in response to five (5) questions. Each question is responded to more fully in Sections D1 through D5 of this report. An executive summary of each response is provided below:

(1) Do the wells listed by DRBC as grandfathered wells meet DRBC's definition of an exploration well eligible for grandfathered status?

It is my opinion that the 11 wells listed by DRBC as grandfathered wells, covered under its June 14, 2010 and July 23, 2010 Supplemental Determinations, do not meet DRBC's definition of an exploration well eligible for grandfathered status. DRBC defined a grandfathered exploration well as a well intended solely for exploratory purposes and one that is plugged and capped at the conclusion of exploratory activities, without future use for production. No information was provided for my review to show that the grandfathered wells were drilled exclusively for exploratory purposes and will be permanently plugged and abandoned after the wells are drilled. None of the grandfathered well permits specify the completion method or the final disposition of the wells, nor were the 30 day well completion reports available. None of the grandfathered wells appear to have submitted a Notice of Intent by Well Operator to Plug a Well, and/or a Certificate of Well Plugging. Instead, several of the grandfathered well documents confirm alternative plans for these wells, including gas production. Approval of an exploration well destined for production is in essence production well approval.

Well density and drilling pace are strong indicators of well type. True exploration wells are drilled on large spacing intervals to test hydrocarbon trap theories. The pace is slower than production well drilling, so data from preceding exploration wells can be used to avoid the economic risk of drilling several dry-holes in rapid succession. The density and pace of some of the grandfathered wells, especially Newfield's wells, are inconsistent with exploration well classification.

Most companies have exploration departments that are separate and distinct from production drilling departments. Exploration departments typically have higher levels of data security, dedicated exploratory budgets, and staff that specialize in finding new hydrocarbon sources. Very small companies may combine exploration and production drilling staff, however, funding documents for each well will clearly delineate the nature of the well and whether it was funded and located as a true exploration well and whether the well was planned to be a test well only, destined for plugging and abandonment.

(2) Do exploration wells pose lower risk than production wells?

It is my opinion that exploration wells are riskier than production wells, because drilling hazards are unknown. The risk of a well blowout or well control situation occurring is higher due to the increased difficulty in designing and constructing a well based on unknown data. DRBC's decision to forego regulation of the grandfathered wells, because they are "exploration wells" and thereby "lower risk," is inconsistent with the known higher risk profile for an exploration well. The risk of an exploration well blowout is approximately 7 wells in every 1000 drilled.

True exploration wells, by definition, explore into previously unknown and unmapped hydrocarbon formations; therefore, an exploration well drilling Operator must be prepared to encounter both oil and gas. The grandfathered wells should have been equipped to deal with either a gas and/or oil well blowout. While an exploration well Operator may target gas, as is the stated intent in these grandfathered wells, it cannot rule out the potential to encounter oil enroute to the gas target, or instead of hitting a gas target. In a true exploration well, the type of hydrocarbons, depth of burial and whether they are present in commercial quantities are all unknown.

There was no material provided for my review to show that the risk of drilling an exploration well in the Delaware River Basin is less than that of a production well, nor that the possibility of oil being encountered during exploration drilling can be completely ruled out.

(3) Did DRBC's decision to grandfather 11 wells create the potential for increased risk to water quality and water resources of the Delaware River Basin?

It is my opinion that DRBC's decision to forego regulation of the grandfathered wells resulted in increased risk to water quality and water resources of the Delaware River Basin. This increased risk was created by:

- not stipulating additional site-specific mitigation measures to reduce environmental impacts above the minimum statewide standards required by PADEP to protect the waters of the Delaware River Basin;
- allowing wells to be drilled and sited in environmentally sensitive areas within the Delaware River Basin without adequate DRBC siting review;
- not requiring appropriate setbacks from sensitive locations; and
- creating a situation whereby an exploration well must be drilled and plugged (even if successful), such that drilling impacts are duplicated when a production well is re-drilled at the same or another location at a later date.

The DRBC's definition of an exploration well is inconsistent with industry practice. It is industry practice to convert successful exploration wells into production wells, if commercial quantities of hydrocarbons are found. DRBC's decision to forego review of the grandfathered wells if they are drilled solely to collect data, and then immediately plugged and abandoned, could result in two wells being drilled in the same area (first the exploration well and then later a production well). Drilling a well twice results in economic waste and increased impacts to air, land and water in the Delaware River Basin. Instead, the DRBC should have reviewed each exploration well to ensure it was properly sited and environmental impacts were mitigated. In this way, if Operators make a commercial find, DRBC would have already ensured the well was positioned at a low impact surface location and was drilled using the lowest impact methods. It is important to properly site and assess the impacts of any proposed exploration well in as much detail as is necessary for a production well, because a successful exploration well is in essence the first production well in the field.

DRBC should carefully examine the grandfathered wells that have been drilled to determine if they were properly sited and completed using technically sound well construction practices. Wells that were not properly sited or constructed should be plugged and abandoned.

DRBC grandfathered 11 wells based on economic and risk considerations, with no publicly available economic or risk assessments to support this decision. This decision appears to conflict with DRBC's mission to protect water resources in the Delaware River Basin. There is no evidence that the permit applications for each of the grandfathered wells confirm that they are in fact shale gas "exploration" wells or that the risk of these wells to the Delaware River Basin is low.

(4) Are there sufficient plans and protections included in PADEP's approval to mitigate and respond to the risks associated with exploration wells?

It is my opinion that the Pennsylvania Department of Environmental Protection (PADEP) permit materials and Preparedness, Prevention and Contingency Plans (PPC) provided for my review do not include sufficient plans and protections to mitigate and respond to the risks associated with exploration wells.

There are a number of risks posed by exploration wells, including air, water and land pollution, resulting from fuel and chemical spills, stray gas, well blowouts, water use, waste disposal, and other aspects of drilling operations. The most significant and potentially catastrophic risk of those listed is an uncontrolled blowout. An uncontrolled blowout must be considered when planning an exploration well. There is insufficient evidence to show that the grandfathered exploration wells are equipped to deal with either a gas and/or oil well blowout. Well permit applications filed with PADEP for the grandfathered wells do not include any explanation or evidence of blowout prevention or control capability.

While blowouts are very infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can last for days, weeks, or months until well control is finally achieved. The most common method, and best technology, to control an on-land blowout is well capping, requiring large volumes of water to deluge the rig, allowing well control experts to work near a blowout. Water requirements can range from 500,000 to 6,000,000 gallons of water per day. Well control experts also use foam and dry chemicals to respond to blowouts. Deluge operations create large pools of water on the surface that drain away from the well blowout. This can transport oil, chemicals, fuels, and any other materials released during a blowout toward lower elevation drainage areas.

Newfield's PPC for the proposed Newfield grandfathered wells does not meet PADEP's requirements; the adequacy of the other grandfathered wells' PPCs is not known, because they were not provided for review. Exploration well operations require fuel to operate drilling and completion equipment, and the process of drilling a well requires numerous chemicals. Newfield's PPC lists the potential for both fuel and chemical storage tanks to leak and contaminate the nearby environment, water supplies or water resources. However, Newfield's PPC lists insufficient onsite resources to respond to the potential fuel and chemical spills it lists.

The PPC Plans provided for my review did not adequately identify the environmentally sensitive areas within the Delaware River Basin that should be protected during exploration drilling, and did not include adequate tactics and strategies to protect those areas.

Pennsylvania only requires a bond of $2,500 per well, or a blanket bond of $25,000 for all wells drilled in Pennsylvania by a single Operator. Neither amount would provide sufficient funds to control, clean up, and/or remediate the damage caused by a well blowout, chemical spill or large fuel spill from an exploration well operation.

(5) Was DRBC's assumption the risk of the grandfathered wells was small because PADEP has sufficient human health, environmental and safety protections in place for exploration drilling projects in Pennsylvania well-founded?

It is my opinion that DRBC's assumption that the risks associated with the grandfathered wells is small because PADEP has sufficient human health, environmental and safety protections in place for exploration drilling projects in Pennsylvania is not well founded for the following reasons:

- PADEP's existing Chapter 78 Oil and Gas Well Regulations are known to be deficient;
- Grandfathered wells are not required to be constructed to industry best practices for shale gas wells in Pennsylvania;
- PADEP did not apply "Special Permit Conditions," requiring a Water Management Plan, to most of the grandfathered wells;
- Fracture treatment operations are planned for the B&E well;
- Drilling waste can result in environmental harm if not properly managed, and some waste has already been buried on-site and not transported out of the Basin;
- Stray gas migration associated with oil and gas wells can impact water supplies, if wells are not properly constructed and operated;
- PADEP's well siting criteria allows wells to be placed very close to water resources; and
- Air pollution impacts, and corresponding impacts to water resources, are not well understood or mitigated.

B. Introduction

This report responds to the Delaware Riverkeeper Network's (DRN) and Damascus Citizens for Sustainability's (DCS) request to provide expert review and opinion on the Delaware River Basin Commission's (DRBC's) decision to exclude 11 Pennsylvania state permitted wells in Wayne County from DRBC review of exploration wells under its June 14, 2010 and July 23, 2010 Supplemental Determinations. The opinions stated here are stated to a reasonable degree of scientific and professional certainty.

C. DRBC's Contested Decisions and Chronology

On May 19, 2009, the DRBC issued a "Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters" (**Exhibit 1**), directing natural gas extraction projects located in shale formations within the drainage area of Special Protection Waters to obtain DRBC approval for:

"*…the drilling pad upon which a well intended for eventual production is located, all appurtenant facilities and activities related thereto and all locations of water withdrawals used or to be used to supply water to the project*."

The May 19, 2009 determination exempted "wells intended solely for exploratory purposes."

On May 5, 2010, the DRBC issued a decision to finalize natural gas regulations before considering project approvals (**Exhibit 2**).

On June 14, 2010, the DRBC issued a "Supplemental Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters" (**Exhibit 3**), directing **all** natural gas extraction projects located in shale formations within the drainage area of Special Protection Waters to obtain DRBC approval. This determination withdrew the May 19, 2009 decision to exclude exploration wells. The DRBC wanted to remove:

"*…any regulatory incentive for project sponsors to classify their wells as exploratory wells and install them without Commission review before the Commission's natural gas regulations are in place*."

However, the DRBC decided that:

"*…where entities have invested in exploration well projects in reliance on [the] May 2009 Determination and information from staff, there are countervailing considerations that favor allowing these projects to move ahead*."

The DRBC determined that:

"[i]n contrast to the thousands of wells projected to be installed in the Basin over the next several years, the risk to Basin waters posed by only the wells approved by PADEP since May are comparatively small. Not only are these wells subject to state regulation as to their construction and operation, but they continue to require Commission approval before they can be fractured or otherwise modified for natural gas production."

In other words, the DRBC determined that any exploration well that obtained a state natural gas well permit on or before June 14, 2010 was grandfathered, meaning DRBC review and approval was not required.

According to the DRBC's June 14, 2010 decision, there were no permits issued by the New York State Department of Environmental Conservation as of June 14, 2010, but there were a "limited" number of permits issued by the Pennsylvania Department of Environmental Protection (PADEP). The number and name of the PADEP permits issued were not listed in the DRBC decision. Later a spreadsheet was provided by DRBC listing the wells that DRBC thought qualified for "grandfather" status. According to the DRBC spreadsheet, 13 wells were approved by PADEP prior to June 14, 2010 (**Exhibit 4 and 4A**).

The notes that accompany DRBC's spreadsheet (**Exhibit 4**) state that three (3) wells of these 13 wells are not pertinent to the issue of grandfathered wells, because two wells were already drilled (Matoushek #1 OG Well, Stone Energy Corp and Robson 627528 #1 OG Well, Chesapeake Appalachia LLC) and the DL Teeple #1-2H OG Well, Newfield Appalachia PA LLC was designed as a horizontal well and does not meet the exploration well criteria. This left 10 wells subject to the June 14, 2010 grandfather provision.

1. HL Rutledge #1-1 OG well, Newfield Appalachia PA LLC, April 29, 2010, ("**Rutledge**");
2. VE Crum #1-1 OG Well, Newfield Appalachia PA LLC, April 30, 2010, ("**Crum**");
3. EM Schweighofer #1-1 OG Well, Newfield Appalachia PA LLC, May 7, 2010, ("**Schweighofer**");
4. Woodland Mgmt Partners #1-1 OG Well, Newfield Appalachia PA LLC, May 27, 2010, ("**Woodland**");
5. DL Teeple #1-1 OG Well, Newfield Appalachia PA LLC, April 23, 2010, ("**Teeple**");
6. Stockport Assn 1; Pennswood Oil & Gas LLC, July 22, 2009, ("**Stockport**");
7. Preston 38 LLC OG Well; Pennswood Oil & Gas LLC, July 22, 2009,("**Preston**");
8. Geuther #1 OG Well, Stone Energy Corp, April 28, 2008, ("**Geuther**");
9. Cabot #2 OG Well, Arbor Operating, LLC, April 13, 2010, ("**Cabot**"); and,
10. B&E Well #1 OG Well; Schrader Kevin E, March 5, 2009, ("**B&E**").

On July 23, 2010, the DRBC issued an "Amendment to Supplemental Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters" (**Exhibit 5**), allowing two additional Hess Corporation wells to be drilled that had not yet received PADEP permits, but had obtained Pennsylvania Erosion and Sediment Control General Permits (ESCGP-1). Hess argued that because these wells were in the final PADEP permit approval process, the wells represented a level of investment equivalent to the natural gas exploratory wells that were grandfathered by the DRBC June 14, 2010 decision. DRBC based its decision on economics and the need to obtain scientific data from the two exploration wells to plan future wells in the Delaware River Basin. DRBC noted in its decision that none of the other grandfathered wells had obtained Pennsylvania Erosion and Sediment Control General Permits, because the well pads fell below the five-acre threshold. Therefore, a total of 12 wells were grandfathered by DRBC, including:

11. Davidson 1V Well; Hess Corporation, July 13, 2010, ("**Davidson**"); and
12. Hammond 1V Well; Hess Corporation, July 20, 2010, ("**Hammond**").

On October 14, 2010, Arbor Operating, LLC withdrew its Cabot well permit (**Exhibit 6**), leaving 11 grandfathered wells that remain at issue in the Hearing.

According to DRBC's records, as of mid-October 2010, three (3) of the 11 grandfathered wells have been drilled:

1. Crum well (**Exhibit 7 and 7A**)[1];
2. Woodland well (**Exhibit 8 and 8A**)[2];
3. Teeple well (**Exhibit 9 and 9A**)[3];

[1] VE Crum# 1-1 OG Well, Newfield Appalachia PA LLC, permit documents, produced by Damascus Township pursuant to a subpoena issued in a federal court proceeding by the Damascus Citizens for Sustainability, et al v. Newfield Appalachia, LLC & Damascus Township, USDC, M.Pa., Civil Action No. 10-CV-1604 on August 9, 2010.
[2] Woodland Mgmt Partners #1-1 OG Well, Newfield Appalachia PA LLC, permit documents, produced by Damascus Township pursuant to a subpoena issued in a federal court proceeding by the Damascus Citizens for Sustainability, et al v. Newfield Appalachia, LLC & Damascus Township, USDC, M.Pa., Civil Action No. 10-CV-1604 on August 9, 2010.

As of mid-October, DRBC reports that eight (8) of the 11 grandfathered wells have not been drilled, but work has commenced on some wells, as noted below:

4. Rutledge well (**Exhibit 10 and 10A**)[4] – pad construction completed;
5. Schweighofer well (**Exhibit 11 and 11A**)[5];
6. Stockport well (**Exhibit 12**)[6];
7. Preston well (**Exhibit 13**)[7];
8. Geuther well (**Exhibit 14**)[8];
9. B&E well (**Exhibit 15**)[9];
10. Davidson well (**Exhibit 16**)[10] – site preparation underway; and
11. Hammond well (**Exhibit 17**)[11] – site preparation underway.

The Matoushek and Robson wells were drilled prior to the grandfathering decision. DRBC's information on these wells shows that the Matoushek well was "TAed" (presumably the code for temporary abandonment) and the Robson well was "PAed" (plugged and abandoned). Materials were provided for review on both the:

- Matoushek #1 OG Well, Stone Energy Corp, March 14, 2008, (**Exhibit 18 and 18A**)[12] ("**Matoushek**"); and,
- Robson #1 OG Well, Chesapeake Appalachia LLC, February 26, 2009, (**Exhibit 19**), ("**Robson**").

DRN explained that the DL Teeple #1-2H OG well application was determined to be a production well, and is pending DRBC production well review; therefore, it is not a grandfathered exploration well.

- DL Teeple #1-2H OG Well, Newfield Appalachia PA LLC, May 25, 2010, (**Exhibit 20**) [13], ("**Teeple 2H**").

D. Questions Responded to in this Report

This report provides my expert opinion on five (5) questions:

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[3] Woodland Mgmt Partners #1-1 OG Well, Newfield Appalachia PA LLC, permit documents, provided by DRN on October 23, 2010.
[4] HL Rutledge #1-1 OG well, Newfield Appalachia PA LLC, permit documents, produced by Damascus Township pursuant to a subpoena issued in a federal court proceeding by the Damascus Citizens for Sustainability, et al v. Newfield Appalachia, LLC & Damascus Township, USDC, M.Pa., Civil Action No. 10-CV-1604 on August 9, 2010.
[5] EM Schweighofer #1-1 OG Well, Newfield Appalachia PA LLC, permit documents, provided by DRN on October 23, 2010.
[6] PADEP eFacts Information on Stockport Assn#1 well, retrieved October 23, 2010.
[7] PADEP eFacts Information on Preston 38 LLC OG Well, retrieved October 23, 2010.
[8] Geuther # 1 OG Well, Stone Energy Corp, permit documents, provided by DRN on October 20, 2010, only including two pages of the PADEP well permit application.
[9] B&E Wells #1 OG Well; Schrader Kevin E, permit documents, provided by DRN on October 20, 2010.
[10] Map of Davidson 1V Well Site.
[11] **Exhibit 17** is a map of the well location only. As of October 23, 2010 DRN confirmed that only E&S permits had been obtained for this well.
[12] Matoushek #1 OG Well, Stone Energy Corp, permit documents, provided by DRN on October 20, 2010.
[13] Robson 627528 1 OG Well, Chesapeake Appalachia LLC, permit documents, provided by DRN on October 23, 2010.

D.1 Do the wells listed by DRBC as grandfathered wells meet DRBC's definition of an exploration well eligible for grandfathered status?

D.2 Do exploration wells pose lower risk than production wells?

D.3 Did DRBC's decision to grandfather 11 wells create the potential for increased risk to water quality and water resources of the Delaware River Basin?

D.4 Are there sufficient plans and protections included in PADEP's approval to mitigate and respond to the risk associated with exploration wells?

D.5 Was DRBC's assumption that the risk associated with the grandfathered wells is small because PADEP has sufficient human health, environmental and safety protections in place for exploration drilling projects in Pennsylvania well founded?

D.1 Do the Grandfathered Wells Meet the Definition of Exploration Well?

The DRBC does not define the term "exploration well" in its regulations,[14] but uses the term "exploratory well" in its decisions to make a distinction between "exploration" and wells used for "production." DRBC clarified its definition of an exploration well in a May 19, 2009 news release that stated:

> *"Wells intended solely for exploratory purposes are not covered by this determination.* ***<u>An exploratory well is one that the project sponsor intends to plug and cap at the conclusion of exploratory activities without use for production or fracking</u>*** *[emphasis added]."*[15]

Later in August 2009, the DRBC wrote Arbor Operating, LLC regarding its Cabot #2 well further affirming that its exploration well definition included the requirement to be drilling the well "solely" for exploration purposes and the requirement for a "cap and plug plan."

> *"As Arbor has stated that they* ***<u>propose to develop the well if a viable quantity of natural gas is discovered,</u>*** *the* ***<u>well is not therefore being drilled solely for exploratory purposes</u>*** *and is again covered under the Executive Director's Determination. The well may not be covered under the determination* ***<u>if a cap and plug plan is submitted to the Commission</u>*** *and* ***<u>it is affirmed that the well will be properly abandoned upon completion and collection of necessary exploratory data</u>*** *[emphasis added]."*[16]

The Pennsylvania Code does not make a distinction between exploration and production wells. The Pennsylvania Code requires an Operator to obtain a permit for a well, but does not make a distinction between an exploration well and a production well for purposes of that application.[17] The Pennsylvania Code does define a Marcellus Shale Well as:

> *"A well that when drilled or altered produces gas or is anticipated to produce gas from the Marcellus Shale geologic formation*."[18]

[14] For example, DRBC, Ground Water Protected Area Regulations for Southeastern Pennsylvania, 1999.
[15] DRBC May 19, 2009 Press Release, "DRBC Eliminates Review Thresholds for Gas Extraction Projects in Shale Formations in Delaware's Basin's Special Protection Waters, (**Exhibit 26**).
[16] DRBC letter to Arbor Operating LLC, August 4, 2009, (**Exhibit 25**).
[17] 25 Pa.Code 78.11 Permit Requirements
[18] 25 Pa.Code 78.1 Definitions

The Pennsylvania Oil and Gas Act defines an "operating well" as any well not plugged and abandoned. Because there do not appear to be any plug and abandonment plans (P&A) for the grandfathered wells, these wells are "operating wells" under the Pennsylvania Oil and Gas Act.

The US Securities and Exchange Commission (SEC) governs oil and gas reserve reporting in the US. The SEC defines an exploratory well as:

> "*An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally,* ***an exploratory well*** *is any well that* ***is not a development well, an extension well, a service well, or a stratigraphic test well*** *as those items are defined in this section [emphasis added].*"[19]

The SEC defines stratigraphic test wells as those wells that collect geologic data such as coring and expendable exploration holes, but this definition does not customarily include wells being drilled for hydrocarbon production:

> *"Stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition.* ***Such wells customarily are drilled without the intent of being completed for hydrocarbon production****. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration.* ***Stratigraphic tests are classified as ''exploratory type'' if not drilled in a known area or ''development type'' if drilled in a known area****.*[20]

The SEC also requires Operators to disclose the number of net productive and dry exploration wells drilled.[21] Therefore the Operator must identify the type of well that is being drilled as exploration or production for federal reporting purposes.

Therefore, both the DRBC definition and SEC definition of exploration well make it very clear that an exploration well is not a production well. The DRBC takes its exploratory well definition one step further by clearly articulating that an exploration well drilled in the Delaware River Basin, under grandfathered status, must be plugged and capped.

If DRBC's definition of an exploration well is applied to each of the 11 wells listed by DRBC as grandfathered, none of these wells would qualify as true "exploration wells" because none appear to be drilled "solely for exploration" and none appear to have a plug and cap plan.

For the three (3) wells already drilled (Crum, Woodland, and Teeple #1), there were no Well Records or Completion Reports[22] provided for my review to show the final well disposition, no Application for Inactive Well Status,[23] no Notice of Intent by Well Operator to Plug a Well,[24] and no Certificate of Well Plugging.[25] If those records exist they should be obtained and provided for review.

[19] 17 CFR Parts 210.4-10(a)(13); (**Exhibit 24**)
[20] 17 CFR Parts 210.4-10(a)(30); (**Exhibit 24**)
[21] 17 CFR Part 229.1205; (**Exhibit 25**)
[22] PADEP Form 5500-FM-0G0001
[23] PADEP Form 5500-FM-0G0056.
[24] PADEP Form 5500-FM-OG0005 or 5500-FM-OG0005A
[25] PADEP Form 5500-FM-0G0006.

For the remaining eight (8) wells that have not yet been drilled (Rutledge, Schweighofer, Stockport, Preston, Geuther, B&E, Davidson, and Hammond), there is no Notice of Intent by Well Operator to Plug a Well.[26] If these records exist they should be disclosed.

Absent documentation showing intent to plug the well, the well applications and supporting materials provided for my review were examined for Operator intent.

Newfield Appalachia PA, LLC is the Operator for a majority of the grandfathered wells. Newfield's permit application materials propose to explore for natural gas in the Marcellus Shale in Wayne County. Yet, the application also includes well **production** activities under the umbrella of exploration operations. Newfield's Preparedness, Prevention and Contingency (PPC) Plan states:

> *"Newfield Appalachia PA, LLC (Newfield) is a natural gas exploration company with operations planned for Wayne County, Pennsylvania. Operations will* ***involve natural gas exploration*** *of the Marcellus Shale formation,* ***which will include*** *site preparation, drilling and* ***well development and production activities*** *[emphasis added]."* [27]

Exploration and Production (E&P) operations are two separate and distinct activities. Production operations do not fall under exploration. The manner in which Newfield has blurred the line between exploration and production operations supports a reasonable assumption that their intent is to convert successful exploration wells into production wells. Unless Newfield submitted Notices of Intent to plug the grandfathered wells, Newfield's wells do not meet DRBC's definition of exploration wells.

April 1, 2010 letters from Newfield to PADEP explained the purpose of two wells, Teeple #1[28] and Schweighofer.[29] The same language was used in both letters:

> *"This permit [D.L. Teeple Well #1-1] is to develop a well which is* ***intended solely for exploration purposes****. A core is to be taken from several formations throughout the drilling process of this well and additional scientific study is to be performed on multiple formations including, but not limited to, geophysical logs, micro-seismic studies and fluid sampling. As permitted and configured, this well is not to be complete for production, not to be hydraulically fractured and is not to produce gas.* ***In the future, this wellbore will either*** *be plugged and abandoned per PADEP regulations, converted to inactive status and utilized as a monitoring well,* ***or reconfigured and converted to a production well****. Prior to either plugging and abandonment, conversion to inactive status* ***or reconfiguration and conversion to production****, we acknowledge that additional permitting will be necessary with approvals from the PADEP and other regulatory bodies with jurisdiction [emphasis added]."*

Both of Newfield's letters start off by stating that the Teeple #1 and Schweighofer wells are intended only for exploration purposes, yet leave the future utilization of the wells open, with a possibility to convert each well to a production well. Therefore, approval of these wells is de facto approval of production wells in the same location, because Newfield has not met DRBC's definition of an exploration well.

[26] PADEP Form 5500-FM-OG0005 or 5500-FM-OG0005A
[27] Newfield Appalachia PA, LLC, Preparedness, Prevention and Contingency (PPC) Plan, May 2010, submitted with all its grandfathered wells.
[28] Newfield Appalachia PA, LLC, letter to PADEP, April 1, 2010 regarding D.L. Teeple Well #1-1, in **Exhibit 9**.
[29] Newfield Appalachia PA, LLC, letter to PADEP, April 1, 2010 regarding EM Schweighofer Well #1-1, in **Exhibit 11**.

Based on the data provided for my review, it is unclear how DRBC decided to include the 11 wells in its spreadsheet as grandfathered exploration wells (**Exhibit 4**), especially when these wells do not meet DRBC's own definition for an exploration well.

It is also unclear why DRBC included the Stockport and Preston wells in the list of grandfathered wells, because the renewal applications for the Stockport and Preston wells were not submitted until after June 14, 2010, and the renewal permits were not approved until July 20, 2010.[30] In other words, the currently approved permits were approved by PADEP after the June 14, 2010 DRBC cut-off date for grandfathered wells.

The main difference between an exploration well and a production well is that exploratory drilling, by definition, seeks to locate unknown subsurface hydrocarbons to determine if they exist and can be produced in commercial quantities. Most companies have exploration departments that are separate and distinct from production drilling departments. Exploration departments typically have higher levels of data security, designated exploratory budgets, and dedicated staff that specialize in finding new hydrocarbon sources. Very small companies may combine exploration and production drilling staff, however, funding documents for each well will clearly delineate the nature of the well and whether it was funded and located as a true exploration well. Additionally, as explained above, the Operator also has to designate the exploration well type and track findings in its SEC reporting. The organizational structure of each company, funding documents for each well, and any SEC reporting data that has been developed were not available for review.

Exploration wells are typically drilled on low density spacing to cover large areas, especially when drilled by a single Operator. True exploration wells test geologic hydrocarbon trap theories, attempting to locate hydrocarbons that have been trapped in commercial quantities. Typically a team of geologists, geophysicists and reservoir engineers select an exploration well location based on seismic data, geologic information in the region, offset well data and other information that may be available. Financially it is too risky for a single Operator to drill multiple exploration wells in rapid succession in a small area, testing the same hydrocarbon trap theory. Typically, a single Operator would spread its exploration budget and risk, testing several hydrocarbon trap theories in different exploration areas and carefully examining the data from each exploration well to determine if an additional well in that same geologic trend is a worthwhile investment. Data collected from one exploration well is used to pin-point future exploratory well targets. A successful exploration well in one area may lead to a recommendation for subsequent appraisal wells around the original exploration well to further delineate the size of a hydrocarbon reservoir, so that engineers can properly size surface production facilities and pipeline needs. Later, production wells are drilled on a more dense spacing around the successful exploration wells.

Newfield received permits for five (5) wells in a 6 by 10 mile area. This is unusually dense spacing for a single Operator to be drilling exploratory wells in rapid succession, with little or no opportunity to inform future exploration well locations (**Exhibit 29** provides a map showing the well density). The pace of Newfield's drilling program strongly indicates that several of these wells are akin to production wells, rather than true exploration wells.

[30] The original permits expired in July 2010. The July 20, 2010 permit renewal post-dates the June 14, 2010 grandfather cut-off date (**Exhibits 12 and 13**). The original Stockport and Preston well applications were approved by PADEP prior to June 14, 2010 but the Operator Pennswood Oil & Gas LLC did not act on either well.

Findings:

- DRBC defined a grandfathered exploration well as a well intended solely for exploratory purposes and one that is plugged and capped at the conclusion of exploratory activities without future use for production.
- No information was provided for my review to show that the grandfathered wells will be permanently plugged and abandoned after the wells are drilled.
- The grandfathered well permits do not specify the completion method, and the 30 day completion reports showing the final disposition of each well were not available for review.
- A Notice of Intent by Well Operator to Plug a Well and/or a Certificate of Well Plugging do not appear to have been submitted for any of the grandfathered wells.
- Absent any new data showing that the Operators of the "grandfathered" wells listed in Exhibit 4 provided clear written evidence that they meet DRBC's exploration well standard, these wells do not meet DRBC's grandfathered exploration well definition.
- Newfield's application data and supporting information confirms it has alternative plans for these wells, including gas production.
- Newfield's 2010 PPC Plan shows clear intent to produce successful exploration wells. Approval of an exploration well destined for production is in essence production well approval.
- The Stockport and Preston well permits were renewed July 20, 2010, after the cut-off date for grandfathered wells.
- Well density and drilling pace are strong indicators of well type. The density and pace of some of the exploration wells, especially Newfield's wells, are inconsistent with exploration well classification.
- Funding documents for each well will clearly delineate the nature of the well and whether it was funded and located as a true exploration well. Funding documents have not been available for review.

D.2 Do Exploration Wells Pose a Lower Risk Than Production Wells?

Exploration wells are riskier than production wells because factors such as pressures, temperatures and drilling hazards are not known or are uncertain. On average 7 out of every 1000 onshore exploration wells will result in a blowout.[31,32] Blowouts can eject drilling mud, gas, oil and/or formation water from the well and onto waters and lands adjacent to the well, within the radius of the blowout plume. Depending on the reservoir pressure, blowout circumstances, and wind speed these pollutants can be distributed hundreds to thousands of feet away from the well.[33] Pollutants that reach a water systems can be carried

[31] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[32] Rana, S., Facts and Data on Environmental Risks- Oil and Gas Drilling Operations, Society of Petroleum Engineering Paper 114993, October 2008.

[33] S.L. Ross Environmental Research Limited, Oil Deposition Modeling For Surface Oil Well Blowouts, 1998.

downstream and contaminate even larger areas. Pollutants that reach lands can migrate into groundwater resources.

The lack of information available to an exploration well driller increases the risk profile of a well. Exploration well design and planning is more difficult and typically requires more materials to be brought to the site, to deal with unknown pressures, depths, temperatures, casing needs, cementing needs, drilling mud needs, and other unknowns. Proper engineering design of drilling fluid and blowout preventer systems is critical to reducing the risk of a blowout. The inability to accurately predict pressures in an exploration well requires that mud and blowout prevention systems be designed with an adequate safety factor, to ensure unexpected pressures can be controlled while drilling.

> *"The uncontrolled eruption of a well is one of the most critical accidents that can occur both during exploration and exploitation of hydrocarbon fields. Significant HSE [health, safety and environmental] issues are associated to this event that introduces safety risks for the field operators, potential health injury for the population living in the area and impacts, mainly associated to the hydrocarbon contamination, on the environment."*[34]

Because true exploration wells, by definition, are exploring into previously unknown and unmapped hydrocarbon formations, an exploration Operator must be prepared to encounter both oil and gas. While an exploration Operator may seek gas, as is the stated intent in these grandfathered wells, it cannot rule out the potential to encounter oil enroute to the gas target, or instead of hitting a gas target. Exploration in other areas of Pennsylvania has resulted in finds of both oil and gas, therefore this is a reasonable assumption, unless the Operator has information to prove that no oil exists from offset well data. In that case, if there is sufficient information to rule out the presence of oil, there is likely sufficient information to make the case that the well is not a true exploration well.

In both Pennsylvania[35] and New York[36]oil has been found in the Upper Devonian Formations above the Marcellus Shale Therefore, the grandfathered exploration wells should have been equipped with detailed plans to prevent and respond to a gas and/or oil well blowout.

> *"Oil deposition in the area surrounding a blowout is one of the most visible consequences of the loss of control over well flow. Less visible, but equally serious, are the short- to medium-term effects of oil coverage on the environment… Apart from the* ***direct damage to*** *capital goods, crops, and* ***water basins*** *and the cost of subsequent cleanup operations, there are medium- to long-term effects, such as reduced tree growth over a period of many years following the incident…Hence, oil fallout, in the case of loss of well control, is a factor to be taken into account in decisions on well locations, emergency procedures, contingency planning, etc.* ***This requires an estimate of the area around the well likely to be affected by oil fallout, given the geomorphology of the terrain, prevailing winds, and expected outflow*** *conditions [emphasis added]."*[37]

[34] Blotto, P., ENI- Exploration & Production, Development of an Integrated Approach to the Risk Analysis of a Blow-out Accident, Society of Petroleum Engineers Paper 86704-MS, SPE International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production, 29-31 March 2004, Calgary, Alberta, Canada, 2004.
[35] Pennsylvania Department of Conservation and Natural Resources, Pennsylvania Geology, Vol 29, No.1, Spring 1998.
[36] New York State, Draft Supplemental Generic Environmental Impact Statement (DSGEIS) 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, September 2009, Figure 4.2.
[37] Oudeman, P., Shell International E&P, Oil Fallout in the Vicinity of An Onshore Blowout: Observations on A Field Case, Society of Petroleum Engineers, Facilities & Construction Journal, Volume 1, Number 4, December 2006.

The Woodland, Teeple and Crum wells are all located very near designated High Quality tributaries of the Delaware River. For example, the Woodland well, is adjacent to Hollister Creek and is less than half a mile from the Delaware River itself. Hollister Creek flows into the River approximately 0.7 mile above a colony of Dwarf Wedge Mussels, a federally protected endangered species. Teeple is located adjacent to Shehawken/Rattlesnake Creek, and is approximately two miles from the River. The location of these wells in such sensitive areas increases the harms that might flow from these risks should a blowout occur. Instead, the surface location for these wells should have been sited in less sensitive locations with careful evaluation and planning.

DRBC's decision to forego regulation of these exploration wells because they are "lower risk" is inconsistent with the known higher risk profile for an exploration well. There was no data provided for this review to show that DRBC supported its lower risk finding with a written technical document.

Findings:

- Exploration wells are riskier than production wells, because drilling hazards are unknown. The risk of a well blowout or well control situation occurring is higher due to the increased difficulty in designing and constructing a well based on unknown data.
- DRBC's decision to forego regulation of these exploration wells because they are "lower risk" is inconsistent with the known higher risk profile for an exploration well.
- The grandfathered exploration wells should have been equipped to deal with a gas and/or oil well blowout.

D.3 Did DRBC's decision to grandfather 11 wells create the potential for increased risk to water quality and water resources of the Delaware River Basin?

DRBC's primary responsibility is to protect water resources in the Delaware River Basin. DRBC reports to the public that its mission is one of: "providing comprehensive watershed management; acting as a steward of the Basin's water resources particularly with respect to: surface water quality, including both point and nonpoint sources of pollution; ground and surface water quantity, including water demands, water withdrawals, water allocations, water conservation, and protected areas; drought management; and in-stream flow management; promoting effective inter-agency coordination to prevent duplication of efforts and seeking increased public involvement" (**Exhibit 22**).[38]

Shale gas drilling operations use water and create wastewater. The amount of water that is used and waste that is generated depends on the well construction technique used, the depth of the well, formations encountered while drilling, well control incidents and other factors.

This report does not examine the exact amounts of water use or waste from a shale gas well drilling operation because **DRBC determined that all shale gas wells, regardless of water use or waste amounts, are subject to DRBC review**. However, Chesapeake Energy reports that a Marcellus Shale gas well can require 100,000 gallons[39] of water to drill a well, even if fracturing operations are not planned. This water is used for mixing cement, drilling mud, dust control and other routine uses.

[38] DRBC Vision Statement, http://www.state.nj.us/drbc/vision.htm, retrieved October 24, 2010.
[39] Chesapeake Energy, Water Use in Marcellus Deep Shale Gas Exploration, March 2010 (**Exhibit 31**).

On June 14, 2010, DRBC determined that all shale gas wells, regardless of water use or waste amounts, are subject to DRBC review. The DRBC issued a "Supplemental Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters" (**Exhibit 3**), eliminating any water or wastewater threshold for DRBC review of shale gas extraction projects, and requiring all shale gas wells to obtain DRBC review.

> *In my Determination of May 2009, I exercised the authority conferred on the Executive Director by section 2.3.5 B.18 of the Commission's Rules of Practice and Procedure (RPP) by directing* ***all sponsors of natural gas extraction projects in shale formations within the drainage area of Special Protection Waters to obtain Commission approval*** *before commencing such projects,* ***notwithstanding that the thresholds for review established by the RPP were not exceeded*** *[emphasis added].*

DRBC's decision to eliminate any review threshold was reconfirmed in a January 19, 2010 DRBC Presentation (**Exhibit 21**)[40] that stated:

> ***Natural gas well activities*** *(NGWA)* ***[are] covered regardless of DRBC thresholds*** *in RPP[41] and Water Code [emphasis added].[42]*

In this finding, DRBC concluded that shale gas well drilling warranted DRBC review; it did not provide any technical or scientific support for exempting review of the grandfathered shale gas wells, except to say companies would suffer economic harm if the projects were delayed, and the risk was "comparatively small."[43] DRBC reasoned that the number of grandfathered wells constituted a small risk compared to the thousands of wells projected to be installed in the Basin over the next several years.

There does not appear to be any written economic assessment supporting the claim that the grandfathered well Operators would suffer economic harm or weighing the economic harm against the potential harm to the watershed from the proposed drilling operations.

There does not appear to be any written risk assessment to support the claim that the risk of drilling the grandfathered wells was small. Likewise, there does not appear to be any evidence to show that the 11 wells listed in DRBC's spreadsheet of "grandfathered wells" (**Exhibit 4**) meet DRBC's definition of an "**exploration**" well.

Exploration wells that find commercial hydrocarbons are typically converted into the first production wells of a commercial hydrocarbon reservoir development, once surface production facilities are installed. Additionally PADEP has no requirement to plug and abandon successful exploration wells.

DRBC's definition for an exploration well, which requires the well to be solely used for exploration data gathering and immediately plugged and abandoned, (per the May 2009 EDD and accompanying press release), does not reflect typical industry practice or state approval processes. Furthermore, DRBC's decision to allow unregulated drilling impacts in sensitive watershed areas sets an unfavorable precedent

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[40] Muszynski, W.J., DRBC Manager Water Resources Management Branch, Presentation, DRBC Engagement in Natural Gas Exploration and Development, Marcellus Shale Meeting, January 19, 2010.
[41] DRBC's Rules of Practice and Procedure (RPP), Section 2.3.5.B.6.
[42] DRBC's Water Code Section 3.40.
[43] DRBC, Supplemental Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters, June 14, 2010.

by potentially doubling drilling impacts. There will be the initial impacts of the exploration well drilling, followed by repeated impacts when a production well is drilled to replace the plugged exploration well.

The more prudent approach would be for DRBC to review exploration wells to ensure they are properly sited, drilled, completed, tested, and suspended, using the best well construction and environmental practices, for potential later conversion to a production well.

The conversion of properly sited and robustly constructed exploration wells to production wells ensures the well is placed in the lowest environmental impact area, and eliminates the environmental impact of drilling a well into the same hydrocarbon target twice. For these reasons, it is important to properly site and assess the impacts of proposed exploration wells in as much detail as is needed for production wells. A successful exploration well is in essence the first production well in the field.

There are limited cases where exploration wells are drilled solely to obtain subsurface data (e.g. cores, well logs, drill stem tests), and in these cases the well is immediately and permanently plugged and abandoned after drilling. This approach is not common. Most Operators will convert a successful exploration well to a production well, unless there are unique circumstances preventing this from occurring. It is not economically attractive for an Operator to drill a well twice.

When an exploration well is destined to be a production well, it is cased and completed with production tubing and a producing wellhead. The well permits for the 11 grandfathered wells do not specify the completion method or the final disposition of the wells and the required 30 day well completion reports were not available for my review.

Findings:

- DRBC grandfathered wells based on economic and risk considerations, without the Operators providing any apparent written economic or risk assessments to support this decision, nor any analysis showing that these considerations trump DRBC's watershed protection obligations.
- There does not appear to be any evidence to show that the permit applications for each of the grandfathered wells are in fact shale gas "exploration" wells.
- DRBC's decision to forego regulation of the grandfathered wells resulted in greater harm to the Delaware River Basin. This harm was created by: allowing wells to be drilled without evaluating whether they are sited in environmentally sensitive areas within the Delaware River Basin; not requiring appropriate setbacks from sensitive locations; and creating a situation whereby an exploration well must be drilled and plugged (even if successful), such that drilling impacts are duplicated when a production well is re-drilled at the same or another location at a later date.
- The DRBC's definition of an exploration well is inconsistent with industry practice, because it is industry practice to convert successful exploration wells into production wells, if commercial quantities of hydrocarbons are found.
- DRBC's decision to forego review of the grandfathered wells, if they are drilled solely to collect data and immediately plugged and abandoned, does not provide the opportunity for DRBC to mitigate the impacts of exploratory operations on the Delaware River Basin. This decision also results in economic waste and creates increased impacts, by requiring successful wells to be drilled twice.

- DRBC should have reviewed each exploration well to ensure it was properly sited and environmental impacts were mitigated. In this way, if Operators make a commercial find, DRBC would have already ensured the well was positioned at a low impact surface location.
- It is important to properly site and assess the impacts of any proposed exploration well in as much detail as is necessary for a production well, because a successful exploration well is in essence the first production well in the field.

D.4 Are There Sufficient Plans and Protections Included in PADEP's Approval to Mitigate and Respond to the Risks Associated with an Exploration Well?

There are a number of risks posed by exploration wells, including air, water and land pollution, resulting from fuel and chemical spills, stray gas migration, well blowouts, water use, waste disposal, and other aspects of drilling operations. One of the most significant and potentially catastrophic risks posed by drilling is an uncontrolled blowout.

An uncontrolled blowout must be considered when planning an exploration well. The grandfathered wells should have been equipped to deal with a gas and/or oil well blowout. Well blowouts can release substantial amounts of oil, gas, drilling mud, and formation water, resulting in significant environmental damage to the surrounding air, water and land. Methods to control a well blowout can require significant water withdrawals and can create large volumes of waste. Well permit applications filed with the PADEP for these grandfathered wells do not include any explanation or evidence of blowout prevention or control capability.

The Pennsylvania Oil & Gas Act at § 601.209 requires a drilling Operator to use safety devices[44] and the 25 PA Code § 78.72 requires the use of blowout prevention equipment and trained personnel. The PA Code focuses on the testing and inspection of blowout preventers, and requires at least one person certified in well control to be on the drill floor. However, neither Pennsylvania law nor regulation requires Operators to demonstrate that they have the expertise, equipment and capability to actually control a blowout and minimize environmental damage, if one occurs.

While Pennsylvania currently requires a Pollution Prevention and Contingency (PPC) Plan to be submitted as part of a drilling application, that plan is inadequate for response to a blowout. PADEP's PCC Guidance[45] (**Exhibit 27**) does not specifically require a well control plan, a written well control barrier policy, a well blowout response plan, or well control experts on contract. This is in sharp contrast to other state and federal agencies, which do currently require response plans to deal with a worst-case blowout scenario. Additionally, the World Bank's Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development recommend comprehensive blowout planning, training and equipment as well as blowout modeling to ensure a well blowout plume radius is understood.[46]

To compound the problem, the Pennsylvania Oil & Gas Act at § 601.215 only requires a bond of $2,500 per well, or a blanket bond of $25,000 for all wells drilled in Pennsylvania by a single Operator. Neither

[44] Section 601.209 requires: "Any person engaged in drilling any oil or gas well shall equip the well with casings of sufficient strength and with such other safety devices, as may be necessary in a manner as prescribed by regulation of the department, and shall use every effort and endeavor effectively to prevent blowouts, explosions and fires."
[45] PADEP's PCC Guidance Document 400-220-001.
[46] World Bank's Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development, 2007.

amount would provide sufficient funds to control, clean up and/or remediate the damage caused by a well blowout. Nor would $2,500 go very far to meet PADEP's stated uses for the bond which is to:

> *…act as a penalty for failure to comply with the drilling, water supply replacement, restoration and plugging requirements of the Act.*[47]

Blowout response and control plans should not only include methods for controlling the well, but identify environmentally sensitive areas, and list tactics and strategies for protecting those areas during a response. For example, a plan should provide for special protection of waters in the Delaware River Basin. Absent these plans, the Delaware River Basin is at increased risk in the event of an uncontrolled blowout.

Newfield's PPC lists the potential for a fire or explosion from its well drilling operations,[48] but provides no blowout prevention or response plan to address an oil and /or gas well blowout, if it were to occur. Newfield's PPC provides no information on blowout preventer sizing, testing methods, or maintenance programs; it provides no information on methods to control a blowout or tactics, strategies or equipment to respond to a blowout.

By comparison, other state and federal agencies require much more detailed Preparedness, Prevention and Contingency Plans, defining the worst-case blowout scenario, a well control response plan, and well control experts and equipment. Most companies have a separate written well control and blowout response plan that is referenced as part of their emergency plan, but there is no evidence of such a plan in the Newfield PPC. The PPCs from other companies with grandfathered wells were not available for review.

A well-thought-out, written blowout prevention and response plan, with trained and experienced drilling staff able to rapidly identify well control problems and control them, has proven critical in reducing the number and severity of well control incidents across the US. Additionally, plans should be in place to immediately access well control experts and equipment, preferably staging well control equipment nearby, in the event a well control situation exceeds a drilling company's capacity or expertise. Access to well control experts is especially critical for small companies that may have little or no well control experience.

While, PADEP has made some attempt at improving Pennsylvania's blowout control capability by partnering with CUDD Well Control to locate a new facility in Canton Township in Bradford County in response to "recent high-profile accidents at nature gas wells in Pennsylvania"[49] the type of equipment located in Pennsylvania is still insufficient to cap a well. Equipment at CUDD's new Bradford County facility will include: a 2,000-gallon-per-minute pump; heat shields; pneumatic cutting devices; trained crews, and a "hot tap," but does not include an athey wagon or a well capping stack. An athey wagon and well capping stack are both large and critical pieces of equipment used in well control. Because this equipment must still be brought in from the Gulf of Mexico, Houston, Canada or Alaska, places where much of the North America well control equipment is located, this will delay well control, increasing a blowout's impacts.

The potential spill volume from a blowout is equal to the volume of the reservoir contents (gas, oil, and/or formation water) that can flow to the surface, plus the discharge of the drilling mud that is in the hole at

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[47] PADEP, Oil and Gas Manual, Chapter 3, October 2001.
[48] Newfield Appalachia PA, LLC, Preparedness, Prevention and Contingency Plan (PPCP), May 2010, submitted with all its grandfathered wells.
[49] PADEP, DEP Says Specialized Natural Gas Emergency Responders Locating in PA, Improving Response Times, PADEP News Bureau Press Release, August 9, 2010.

the time of a blowout. Hydrocarbon reservoirs can contain large quantities of gas, oil and/or formation water, which could continue to be released into the environment until the well naturally bridges on its own (e.g. plugged with sand or debris), is controlled by human/mechanical intervention (e.g. well capping, drilling a relief well, well ignition), or the subsurface reservoir pressure finally drops to a level that the well stops flowing. While blowouts are very infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can last for days, weeks, or months until well control is finally achieved. A blowout in the Delaware River Basin could have significant and irreversible environmental impacts.

The most common method, and best technology, to control an on-land blowout is typically well capping. However, well ignition or drilling a relief well could be alternatives. Well capping requires large volumes of water to allow well control experts to work near the fire with dozers, wagons, and well capping equipment. Water requirements to cap a well depend greatly on the nature of the well blowout, and whether it has ignited.

Surface (lakes, rivers and streams) or subsurface (water wells) water supplies may be tapped to draw the large volumes of water needed for well capping operations, or water may be trucked in, if no nearby surface water or supply well is available. Well control experts use high volume pumps to deluge the rig. Well control experts recommend water supply sourcing and deluging equipment be incorporated in drilling plans. Water requirements can range from 9 barrels of water per minute (9 bpm)[50] to upwards of 100 bpm.[51] This equates to 500,000 to 6,000,000 gallons of water per day, with the average blowout taking days to weeks to control. Deluge operations create large pools of water on the surface that drain away from the well blowout. Deluge fluids can transport oil, chemicals, fuels, and other materials released during the blowout toward lower elevation drainage areas.

Well control experts also use foam and dry chemicals to respond to blowouts. John Wright Co., a well control expert company, explains:

> *Foam consists of water, foam concentrate and air. It is used on liquid hydrocarbon fires to smother the fuel surface (excludes oxygen), suppress vapor emissions (explosive vapor release is restricted), generate steam (removes heat and displaces oxygen), cool surface (heat absorption) and reflect radiant heat. Use on blowouts is restricted to gas condensate fires and oil wells where lateral flow has led to a large fire surface area. Foam can help contain fire near the source and allow work near the flow source. Generally, water alone is adequate for this, but with large, low velocity, lateral oil flow, foam may be required. Modern firefighting foam such as 3M Lightwater ATC is commonly used… Nozzles are available to handle up to 6,000 gpm, but the 2,000-bpm nozzle is most used on oil well fires. Dry chemical extinguishers work like water, but principally act as a smothering agent. Common compounds used are sodium bicarbonate, Purple K (potassium bicarbonate base) and Monnex (highest efficiency rating). Use is generally on methane well fires where explosives cannot be used and water supply is inadequate.*[52]

Additionally, deliberate well ignition or spontaneous combustion can result in large amounts of local air pollution, which can distribute particulate matter and other airborne combustion materials that will eventually deposit on downstream waters, and lands.

[50] John Wright Co., well control expert, http://www.jwco.com/technical-litterature/p09.htm, and (**Exhibit 28**)
[51] Grace, R. d., Blowout and Well Control Handbook, Gulf Professional Publishing, 2003.
[52] John Wright Co., well control expert, http://www.jwco.com/technical-litterature/p09.htm, and (**Exhibit 28**)

PADEP's PPC Guidance[53] (**Exhibit 27**) does require a PPC to include: maps showing the well site layout, boundaries, storage locations, high risk areas, drainage, and topography; location of stored chemicals at wellsite; drawings and plot plans showing sources and quantities of materials and wastes; specific countermeasures to be taken in the event of a spill, including strategies and tactics for responders to follow to contain and control the spill to prevent it reaching water sources, or environmentally sensitive areas; inspection and monitoring programs; security plans; and external factor planning. Yet, many PPCs in Pennsylvania that I have reviewed[54] do not include these components in practice. PADEP has on occasion required PPC Plans to be revised after large spills to remedy plan deficiencies, but this is of little assistance for the damaged environment, especially damaged water resources that are not easily remediated. A more thorough review of these plans prior to drilling is needed to ensure that they are adequate.

For example,[55] Newfield's May 2010 PPC (the only PPC available for this review) did not include many of the elements required by PADEP's PPC Guidance Document 400-220-001. These required elements are critical to preventing and responding to spills in areas and waters of concern to DRBC. Missing plan elements include:

- Drawings showing high-risk areas where spills and leaks most likely would occur;
- Drawings showing drains, pipes, and channels that lead away from potential leak or spill areas;
- Drawings showing outfall pipes that discharge to surface streams or drainage channels;
- Locations of surface drainage courses leading away from the site, and major surface streams and tributaries near the site;
- Locations of any known public and private surface water intakes downstream from the site;
- Descriptions of any existing plans previously developed for the project for the purpose of pollution incident prevention or emergency response preparedness;
- Descriptions of the sources and areas where potential spills and leaks may occur, the direction of flow of spilled materials, and the pollution incident prevention practices specific to the source or area;
- Separate drawings, showing sources and quantities of materials and wastes, sources and areas where potential spills may occur, and pollution incident prevention practices, including a prediction of the direction of the flow of materials spilled as a result of equipment failure, accident, or human error;
- Summary of the engineering practices followed with regard to material compatibility, such as the materials of tanks, piping and other equipment, including their contents and the reaction of materials or wastes when intentionally or inadvertently mixed or combined;
- Summary of the compatibility of a container such as a storage tank or pipeline with its environment;
- A preventive maintenance program for equipment and systems relating to conditions that could cause environmental degradation or endangerment of public health and safety;

[53] PADEP's PCC Guidance Document 400-220-001.
[54] In 2010, I completed a technical review of the Atlas Energy Inc., Cabot Oil & Gas Corporation, EOG Resources, Inc., Newfield Appalachia, and Range Resources PPC, none of which met the PADEP PPC guidelines requirements.
[55] Additional information on the other grandfathered wells PPC plans would be needed to determine the adequacy of the other plans.

- Detailed explanation of the employee training program to ensure that personnel are able to respond effectively to emergencies, by familiarizing them with emergency procedures and emergency equipment systems, including, where applicable: procedures for using, inspecting, repairing, and replacing emergency and monitoring equipment; key parameters for automatic cut-off systems; communications and alarm systems; response to fires and explosions; site evacuation procedures; and shut down of operations procedures;

- Specific countermeasures which will be undertaken by facility personnel in the event of a release, including: valve activations, equipment isolations, flow diversions, boom deployment, and any other activities that will be undertaken to halt the migration of the contaminant off site and to mitigate the consequences of the release;

- A summary of the services of nearby contractors and pre-made arrangements for contractual services on short notice. (PADEP requires equipment suppliers to be contacted to determine the availability and delivery means of equipment needed for removing pollution or hazards to public health and safety).

- A list of available emergency equipment.[56] The list should include the location, a physical description, and a description of the intended use and capabilities of each item on the list. All installations should have equipment available to allow personnel to respond safely and quickly to emergency situations. Some examples of emergency equipment are portable fire extinguishers, fire control equipment (including special extinguishing equipment such as that using foam, inert gas, or dry chemicals), spill control equipment, decontamination equipment, self-contained breathing apparatus, gas masks, and emergency tool and patching kits.

Both exploration and production well operations require fuel to operate drilling and completion equipment and the process of drilling a well requires chemicals. Newfield's PPC lists the potential for both fuel and chemical storage tanks to leak and contaminate the nearby environment, water supplies, or water resources.[57] Newfield's PPCP states:

> *"__For large spills or spills of oils or hazardous materials which may reach surface water or impact the environment__, the employee who first discovers the spill should contact the Emergency Coordinator [emphasis added]."*[58]

Yet Newfield's PPC lists insufficient onsite resources to respond to the potential fuel and chemical spills it lists. Newfield's onsite resources are listed in Table 4[59] as shown to the right.

TABLE 4

On-Site Emergency Response Equipment

On-Site Emergency Response Equipment
Fire Extinguishers
Tyvek Suits
Nitrile Gloves
Hearing Protection
Particulate Adsorbent
Absorbent Pads
Shovels
Earth Moving Equipment
Decontamination Equipment

56 Newfield's PPC lists spill response equipment but the type and amount is insufficient, and there is no explanation of its intended use or capability as required.
57 Newfield Appalachia PA, LLC, Preparedness, Prevention and Contingency Plan (PPCP), May 2010, included in **Exhibit 7**.
58 http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.
59 Newfield Appalachia PA, LLC, Preparedness, Prevention and Contingency Plan (PPCP), May 2010, submitted with all its grandfathered wells.

Newfield's PPC, at Table 1, shown below, provides a list of materials that it plans to use at its exploratory drilling operations. This list shows there is a potential for hazardous materials to spill, including fuels, lubricants, drilling mud, and cement additives. To minimize environmental hazards, production chemicals should be selected carefully by taking into account their volume, toxicity, bioavailability, and bioaccumulation potential. There is no indication in the PPC that this work was completed.

The list provided by Newfield does not make a distinction between exploration or production drilling operations. And, Newfield's PPC does not contain sufficient information to verify whether it has trained and qualified staff able to respond to the potential fuel and chemical spills it lists in Table 1 of its PPC Plan.

TABLE 1

LIST OF MATERIALS & WASTES

CONSTUCTION

POLLUTIONAL MATERIAL	VOLUME OR QUANTITY	LOCATION ONSITE	SPILL CONTAINMENT MATERIALS ONSITE/LOCATION
Diesel Fuel	250 gallons	Well Pad	Sorbent pads; shovels/Gang box
Lubricants	180 gallons	Well Pad	Sorbent pads; shovels/Gang box
OIL ABSORBANT	2,500 lbs	Well Pad	Sorbent pads; shovels/Gang box
Trash & Debris	2,000 lbs	Well Pad	Sorbent pads; shovels/Gang box

DRILLING

POLLUTIONAL MATERIAL	VOLUME OR QUANTITY	LOCATION ONSITE	SPILL CONTAINMENT MATERIALS ONSITE/LOCATION
Diesel Fuel	2000 gallons	Well Pad	Sorbent pads; shovels/Gang box
Lubricants	320 gallons	Well Pad	Sorbent pads; shovels/Gang box
DURATONE HT	2,500 lbs	Well Pad	Sorbent pads; shovels/Gang box
GELTONE V	2,500 lbs	Well Pad	Sorbent pads; shovels/Gang box
Lime	7,500 lbs	Well Pad	Sorbent pads; shovels/Gang box
OIL ABSORBANT	2,500 lbs	Well Pad	Sorbent pads; shovels/Gang box
Base Fluid	300 bbl	Well Pad	Sorbent pads; shovels/Gang box
Rig Wash	2,000 lbs	Well Pad	Sorbent pads; shovels/Gang box
Calcium Chloride (CaCl-)	4,000 lbs	Well Pad	Sorbent pads; shovels/Gang box
RHEMOD L	1,770 lbs	Well Pad	Sorbent pads; shovels/Gang box
LE SUPERMUL	8,500 lbs	Well Pad	Sorbent pads; shovels/Gang box
BARACARB 25, 50 (2 pallets each)	12,600 lbs	Well Pad	Sorbent pads; shovels/Gang box
WALNUT	2,400 lbs	Well Pad	Sorbent pads; shovels/Gang box
DRILTREAT	1,900 lbs	Well Pad	Sorbent pads; shovels/Gang box
Liquid Mud	1,500 bbl	Well Pad	Sorbent pads; shovels/Gang box
BAROID REGULAR / **BAROID BULK (barite)	125,000 lbs	Well Pad	Sorbent pads; shovels/Gang box
Trash & Debris	2,000 lbs	Well Pad	Sorbent pads; shovels/Gang box
Drill Cuttings	100,000 lbs	Air Pit	Sorbent pads; shovels/Gang box
Cement	130,000 lbs	Well Pad	Sorbent pads; shovels/Gang box

Findings:

- An uncontrolled blowout is a catastrophic risk, but one that must be considered when planning an exploration well. The grandfathered wells should have been equipped to deal with a gas and/or oil well blowout.
- Well blowouts and spills can release substantial amounts of oil, gas, drilling mud, and formation water, resulting in significant environmental damage to the surrounding air, water, and land.
- Well permit applications filed with the PADEP for these grandfathered wells do not include any explanation or evidence of blowout prevention or control capability.
- Pennsylvania requires a Preparedness, Prevention and Contingency (PPC) Plan but that plan does not require a written blowout control plan. Nor does the plan require evidence of trained and qualified personnel to respond to well control situations or evidence of contracts with experts to control well blowouts. In contrast, other state and federal agencies require response plans to deal with worst-case blowout scenarios.
- Pennsylvania only requires a bond of $2,500 per well, or a blanket bond of $25,000 for all wells drilled in Pennsylvania by a single Operator; neither amount would provide sufficient funds to control, clean up and/or remediate the damage caused by a well blowout.
- There are inadequate plans in place to identify environmentally sensitive areas, such as special protection waters of the Delaware River Basin. Tactics and strategies for protecting those areas during a spill response are also inadequate.
- The most common method, and best technology, to control an on-land blowout is typically well capping. Well capping requires large volumes of water to allow well control experts to work near the blowout. Water requirements can range from 500,000 to 6,000,000 gallons per day. Deluge operations create large pools of water on the surface that drain away from the well blowout. This water can transport oil, chemicals, fuels, and any other materials released during the blowout toward lower elevation drainage areas.
- Exploration well operations require fuel to operate drilling and completion equipment and the process of drilling a well requires chemicals.
- Newfield’s PPC lists the potential for both fuel and chemical storage tanks to leak and contaminate the nearby environment, water supplies, or water resources; yet lists insufficient onsite resources to respond to the potential fuel and chemical spills it lists.

D.5 Was DRBC's assumption that the risk associated with the grandfathered wells is small because PADEP has sufficient human health, environmental and safety protections in place for exploration drilling projects in Pennsylvania well-founded?

DRBC's assumption that the risk associated with grandfathered wells is small because PADEP has sufficient human health, environmental and safety protections in place for exploration drilling projects in Pennsylvania is not well founded for the following reasons:

- PADEP's Chapter 78 Oil and Gas Well Regulations are known to be deficient;
- Grandfathered wells are not required to be constructed to industry best practices for shale gas wells in Pennsylvania;
- PADEP did not apply "Special Permit Conditions," requiring a Water Management Plan, to most of the grandfathered wells;
- Fracture treatment operations are planned for the B&E well;
- Drilling waste can result in environmental harm if not properly managed, and some drilling waste has already been buried on-site and not transported out of the Basin;
- Stray gas migration associated with oil and gas wells can impact water supplies, if wells are not properly constructed and operated;
- PADEP's well siting criteria allows wells to be placed very close to water resources; and
- Air pollution impacts are not well understood or mitigated.

D.5.1 PADEP's Chapter 78 Oil and Gas Well Regulations are known to be deficient

DRBC's June 14, 2010 decision to grandfather wells was based, in part, on the "existing safeguards" offered by PADEP permits issued under Chapter 78. DRBC concluded:

> *In contrast to the thousands of wells projected to be installed in the Basin over the next several years, **<u>the risk to Basin waters posed by only the wells approved by PADEP since May 2009 are comparatively small</u>**. **<u>Not only are these wells subject to state regulation as to their construction and operation</u>**, but they continue to require Commission approval before they can be fractured or otherwise modified for natural gas production. **<u>In light of these existing safeguards</u>** and the investment-backed expectations of the sponsors of these projects, this Supplemental Determination does not prohibit any exploratory natural gas well project from proceeding if the applicant has obtained a state natural gas well permit for the project on or before the date of issuance set forth below [emphasis added].*[60]

Yet PADEP's current regulatory initiative to substantially revise the Pennsylvania regulations at 25 PA Code Ch. 78 (Chapter 78) for Oil and Gas Wells is evidence that Pennsylvania itself acknowledges that the existing Chapter 78 regulations are not currently reflective of best practices, and do not go far enough to protect human health and the environment, especially for sensitive resources.

[60] DRBC, Supplemental Determination of the Executive Director Concerning Natural Gas Extraction Activities in Shale Formations within the Drainage Area of Special Protection Waters, June 14, 2010 (**Exhibit 3**).

The majority of PADEP's well construction and water supply replacement regulations were promulgated in July 1989 and remained largely unchanged until PADEP proposed revisions to Chapter 78 in 2009. Therefore, Pennsylvania's existing well construction standards are more than 20 years old and do not reflect best technology or practice. Several of the grandfathered wells have already been constructed using these out-dated rules.

PADEP summarizes the problems with the existing Chapter 78 regulations:

> *Many of the regulations governing well construction and water supply replacement were promulgated in July 1989 and remained largely unchanged until this rulemaking. Since that time, recent advances in drilling technology have attracted interest in producing natural gas from the Marcellus Shale, a rock formation that underlies approximately two-thirds of Pennsylvania. New well drilling and completion practices now employed to extract natural gas from the Marcellus Shale and other similar shale formations in Pennsylvania, as well as* ***several recent incidents of contaminated drinking water caused by traditional and Marcellus Shale wells resulted in the Department's decision to re-evaluate the existing well construction requirements.***
>
> ***It was determined that the existing regulations were not specific enough in detailing the Department's expectations of a properly cased and cemented well****, especially in light of the new techniques used by Marcellus Shale operators. The Department also determined that the* ***existing regulations did not address the need for an immediate response by operators to a gas migration complaint and did not require routine inspection of existing wells by the operator***
>
> *The final rulemaking contains* ***revised design, construction, operational, monitoring, plugging, water supply replacement, and hydraulic fracturing reporting requirements****. The final rulemaking also provides material specifications and performance testing to ensure the proper casing, cementing and operation of a well. Additionally, the final rulemaking contains new provisions that require routine inspection of wells and outline the actions an operator and the Department must take in the event of a gas migration incident [emphasis added].*[61]

Therefore, DRBC's lack of review of the grandfathered exploratory wells, as well as any other drilling that DRBC allows before the new PADEP Chapter 78 regulations are in place, will allow the current well construction deficiencies, known to be a problem in Pennsylvania, to be repeated in the DRBC watershed.

In 2009 PADEP proposed numerous revisions to Chapter 78 and sought industry and public comment to improve the regulations consistent with PADEP's stated goals of: minimizing public concerns associated with gas migration into public drinking water supplies; updating material specifications and performance testing requirements; and revising design, construction, operations, monitoring, plugging, water supply replacement, and gas migration reporting requirements.

The fact that Pennsylvania has acknowledged deficiencies in its own regulations, and the fact that the current, unimproved Chapter 78 regulations were used as criteria for review and approval of the grandfathered wells is evidence that the grandfathered wells do not have sufficient protections in place.

PADEP received more than 2,000 comments from industry and the public recommending Chapter 78 improvements, including comments written by HCLLC (**Exhibit 23)**.[62] PADEP has developed final

[61] PADEP Notice of Final Rulemaking, Department of Environmental Protection Environmental Quality Board, 25 Pa. Code, Chapter 78 Oil and Gas Well Cementing and Casing, 2010 (**Exhibit 30A**).
[62] Harvey Consulting, LLC, Recommendations for Pennsylvania's Proposed Changes to Oil and Gas Well Construction Regulations, Report to Earthjustice and Sierra Club, March 2010.

revisions to Chapter 78 (**Exhibit 30 and 30A**), but these changes will not be codified until early 2011. Chapter 78 regulatory changes still must undergo review by the Independent Regulatory Review Commission (planned for November 18, 2010) and then must be published in the *Pennsylvania Bulletin* as final rulemaking (planned for early 2011). [63]

Proposed Chapter 78 improvements that do not apply to the grandfathered wells include:

- Additional protections for water supplies (§ 78.51) including improvements to restoration or replacement of impaired water supplies due to oil and gas well operations;
- Additional requirements for waste control and disposal plans (§ 78.55);
- Improved instructions on when a blowout preventer and other well control safety control devices are required (§ 78.72);
- Improved well construction and operational standards (§ 78.73), including standards to ensure that: oil, brine, completion and well servicing fluids do not pollute groundwater; annular overpressuring does not cause gas migration into subsurface water supplies; and gas is safely flared, captured or diverted during well drilling operations;
- Improved well cementing and casing standards (§ 78.83-78.85) to: prevent subsurface infiltration of surface waters; establish more rigorous requirements to centralize casing, install cement, and verify the cement integrity to protect ground water; require the Operator to prepare and maintain a casing and cementing plan; and require use of new pipe and pressure testing and quality standards for that pipe;
- Improved mechanical integrity standards for operating wells (§ 78.88);
- Gas migration response (§ 78.89);
- Improved well plugging standards (§ 78.92-78.95); and
- A requirement for the Operator to certify that the well has been constructed to Pennsylvania's well construction standards (§ 78.122).

Three (3) of the eleven (11) grandfathered wells were drilled under the existing regulatory structure that is known to be inadequate. The remaining eight (8) grandfathered wells were permitted under the existing Chapter 78 regulatory scheme, and may not be required to comply with the new Chapter 78 regulatory requirements, depending on when the wells are actually drilled and when the Chapter 78 revisions are codified.

Findings:

- Existing PADEP oil and gas well regulations at Chapter 78 are known by PADEP to be inadequate to protect human health and the environment.
- PADEP is in the process of revising Chapter 78 with the stated goals of minimizing public concerns associated with gas migration into public drinking water supplies; updating material specifications and performance testing requirements; and revising design, construction, operations, monitoring, plugging, water supply replacement, and gas migration reporting requirements.

[63] November 3, 2010 phone conversation with Scott Perry, Director of Pennsylvania Bureau of Oil and Gas Management.

- PADEP has not yet promulgated Chapter 78 regulations that are adequate to protect human health and the environment; grandfathered wells are being drilled under regulations known to be deficient.

D.5.2. Grandfathered wells are not required to be constructed to industry best practices for shale gas wells in Pennsylvania

Because PADEP does not require well casing and cementing plans to be submitted, reviewed, and approved as part of a well permit application, there is insufficient information available on the grandfathered wells to verify the integrity of the planned or installed casing and cementing configuration. This problem will not be resolved as part of the proposed Part 78 revisions, because the proposed Part 78 rules still do not require a well construction plan to be submitted and approved as part of the permit to drill.

The permit to drill issued by PADEP approves the well location and directs the applicant to follow PADEP regulations, but does not include any PADEP engineering review of the proposed well construction plans.[64] Because there is no engineering review of the permit application prior to drilling, PADEP's process does not ensure that the well will be constructed to best industry/best technology practices at the time the well is drilled. Therefore, the grandfathered well applications at issue here did not include well construction plans, nor was there any engineering review completed by PADEP.

PADEP's proposed Chapter 78 regulations do include an improvement that requires an Operator to certify that the well has been constructed to Pennsylvania's well construction standards (§ 78.122) after the well has been drilled. However, major casing and cement design flaws are difficult to remedy once the well has been drilled.

Recognizing the importance of proper wellbore design prior to construction, the federal government and many states require wellbore construction plans as part of the permit application, subject to agency engineering review and approval prior to well construction.

PADEP does currently require an after-the-fact drilling completion report to be submitted providing information on the final well construction configuration. However, the well completion reports for the three grandfathered wells that have been drilled were not available for my review. Therefore, there was insufficient information available on the well construction method used for these wells to verify if the wells were drilled to best industry practice using best technology standards.

Wells being drilled in the Delaware River Basin, that may be later used as production wells, and subject to high-volume, high-pressure fracturing should be designed and constructed using best industry practice to protect ground water resources.

[64] November 3, 2010 phone conversation with Scott Perry, Director of Pennsylvania Bureau of Oil and Gas Management

Findings:

- PADEP's rules do not require mandatory use of robust well construction practices and designs for Marcellus Shale wells.
- PADEP's well permit application process does not include any engineering review of the proposed well construction plans. Because there is no engineering review of the permit application prior to drilling, PADEP's process does not ensure that the well will be constructed to best industry/best technology practices at the time the well is drilled.
- There is insufficient information available on the grandfathered wells to verify the planned or installed casing and cementing configurations and whether they have a robust design.

D.5.3 PADEP did not apply "Special Permit Conditions," requiring a Water Management Plan, to most of the grandfathered wells

Recognizing the increased water use associated with shale gas drilling and completions, PADEP typically adds a Special Permit Condition to shale gas wells requiring a Water Management Plan to be submitted. The Water Management Plan must describe water sources that will be used for the drilling operation, including safe yield calculations for surface water withdrawals for each new well. The Water Management Plan must include Best Management Practices (BMPs) and must verify that anti-degradation requirements are met and that designated uses of surface waters are protected.

PADEP required a Water Management Plan be submitted as a Special Permit Condition for the B&E well, but did not require a Water Management Plan be submitted for the Crum, Woodland, Teeple #1, Rutledge, Schweighofer, Geuther, and Robson wells. There was insufficient information available on the permit history for the remaining grandfathered wells to determine if Special Permit Conditions had or had not been applied to them.

Because the Crum, Woodland, Teeple #1, Rutledge, Schweighofer, Geuther, and Robson permits did not include a Water Management Plan Special Permit Condition, and there were no documents provided for my review showing that the Operators of these wells prepared a Water Management Plan, it appears that PADEP did not approve the method of water withdrawal, use, storage, or distribution for these wells. There is a lack of consistency in permit conditions applied to the grandfathered wells and a lack of Water Management Plans for many of the grandfathered wells.

Findings:

- PADEP did not require a Water Management Plan for the Crum, Woodland, Teeple #1, Rutledge, Schweighofer, Geuther, and Robson wells.
- There is a lack of consistency in permit conditions applied to the grandfathered wells and a lack of Water Management Plans for many of the grandfathered wells.

D.5.4. Fracture treatment operations are planned for the B&E well.

DRBC lists the B&E Well #1 as one of the 11 grandfathered wells. DRBC maintains that the grandfathered wells are limited to exploration shale gas wells that will not undergo fracture stimulation treatments; however, the B&E Well #1 permit issued by PADEP on March 5, 2009 includes a "Special Permit" condition that requires the Operator to:

> *…not drill the well until the permittee submits to the Department and the Department has approved the method by which the permittee will withdraw, use, store, distribute, process and dispose of water* ***for well drilling and hydraulic fracturing purposes*** *("Water Management Plan").*[65]

The fact that PADEP included a Water Management Plan requirement on the B&E Well #1 well is noteworthy because it must have had a reason to believe that the Operator, Kevin E. Schrader, was planning fracturing operations for this well, which are clearly prohibited under the grandfathering provisions.

Findings:

- PADEP permit indicates fracturing treatments are planned for the B&E Well #1 well. Fracture treatments are not allowed under the grandfathered well provisions.

D.5.5. Drilling waste can result in environmental harm if not properly managed

There is no assurance that a driller's waste management plan will meet DRBC's water protection requirements, because PADEP allows waste disposal methods that DRBC does not. For example, PADEP allows drill cuttings and residual waste to be disposed onsite, under certain circumstances (§ 78.61 disposal of drill cuttings, § 78.62 disposal of residual waste-pits, § 78.61 disposal of residual waste-land application and § 78.60 disposal of tophole water by land application).

For example, a September 8, 2010 PADEP inspection report at the Matoushek wellsite shows that drilling waste was left on-site and buried there. The Matoushek inspection report states that: drilling fluids were being removed from the drilling reserve pit; two workers were observed skimming an oil sheen off of the pit; and the pit's solid wastes would be encapsulated within liner and buried on site. Onsite waste burial within Delaware River Basin is inconsistent with DRBC's requirement to collect drilling waste to be treated at an approved DRBC facility, or transported out of the Delaware River Basin. Produced water from the Matoushek well was transported to a sewage treatment facility that was not approved for drilling waste.[66]

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[65] B&E Well #1, PADEP Permit, March 5, 2009, in **Exhibit 15.**

[66] **Exhibit 18B** shows an email exchange between Stone Energy (Woodland Well Operator), DRBC and PADEP. This information was obtained from DRBC through a DRN March 15, 2010 FOIA request. This email exchange questioned whether Valley Joint Sewer Authority had accepted 270,000 gallons of Woodland produced water waste. PADEP confirmed with Valley Joint Sewer Authority that they had stopped taking drilling waste as of April 2009, but DRBC later confirmed that the drilling waste was sent to Valley Joint Sewer Authority prior to April 2009. This series of events was confirmed on November 4, 2010 via a phone call between DRN and DRBC staff.

Because the PPCs for some of the grandfathered wells were not available for my review, it is unclear what the waste management plan is/was for all of the wells. There was also no information provided for my review showing that DRBC had reviewed the waste management plans for the grandfathered wells to ensure that the waste management plans met the DRBC's water protection requirements.

Best waste management practices in other states do not allow onsite burial of drilling waste. For example, New Mexico requires all fluids be removed from the reserve pit and recycled or disposed of in accordance with state regulations.[67] New Mexico also requires the drill cuttings and reserve pit liners be sent to a disposal facility in accordance with state regulations, and the soil under the reserve pit be tested for benzene, total BTEX[68], TPH[69], the GRO,[70] and DRO[71] combined fraction, and chlorides.[72] If contamination is found, it must be excavated and remediated. If the soil is clean it can be backfilled. The City of Fort Worth, Texas, prohibits onsite burial of drilling muds and cuttings.[73] The reserve pits are temporary and all muds and cuttings must be removed and handled at an approved waste management facility.

Although large-volume, high pressure fracture treatments are not currently permitted for the grandfathered wells, in the future there will be requirements for very large impoundments that warrant careful design and limits.

The use of closed loop tank systems, instead of reserve pits and impoundment, is best practice. The Bureau of Land Management (BLM) recommends the use of closed loop tank systems as a best practice instead of reserve pits and impoundments, whenever technically feasible.[74] Texas requires closed looped mud systems with steel tanks.[75] It is much more efficient (from an energy standpoint) to collect waste in the container that will be used to transport it offsite to a waste disposal facility than it is to create an intermediate storage pit. The use of temporary reserve pits and impoundments results in surface disturbance. It also has the potential for leakage to occur through the liner, impacting groundwater. Impoundments also generate air pollution.

None of the other grandfathered wells include the Special Permit Condition applied to the Teeple #1-2H production well,[76] which requires an environmental assessment from PADEP for any impoundments and chemical analysis and characterization of drilling waste prior to processing or disposal. It is not clear why PADEP would have required a more stringent Special Permit Condition for the Teeple #1-2H production well than the other grandfathered exploration wells. There is inconsistency in permit conditions applied to wells subject to this Hearing.

Reported waste handling concerns at the Teeple[77] and Mastoushek[78] wells are strong indications that additional waste management oversight is needed.

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[67] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009
[68] BTEX= benzene, toluene, ethylbenzene, and xylene.
[69] THP= total petroleum hydrocarbons.
[70] GRO= gasoline range organics.
[71] DRO= diesel range organics.
[72] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009.
[73] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009.
[74] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
[75] Fort Worth Texas, Ordinance No. 18449-02-2009.
[76] See **Exhibit 20**, PADEP well permit for DL Teeple 1 2H for Special Permit Conditions.
[77] **Exhibit 9B** shows a May 26, 2020 violation at the Teeple well for an improperly lined pit.
[78] **Exhibit 18B**

The amount and type of waste generated during the drilling and completion of an exploration well varies based on: the drilling method (air or a drilling mud system), the completion and stimulation method, and the amount of well testing that is conducted.

Typical waste streams from an exploration drilling operation can include: domestic wastewater from on-site septic tanks and portable toilets; produced formation water during well drilling, testing, and stimulation; solids waste including drill cuttings, scrap metal, and debris; waste chemicals; waste oils; and materials associated with chemical and fuel spills. Newfield's PPC lists its expected waste streams from its "natural gas exploration of the Marcellus Shale formation" to include:

> *Wastes generated during these activities will be typical for gas drilling operations and will include **drill cuttings**, **produced water**, **drilling and frac fluids**, **waste oil** and **municipal waste** and **trash** [emphasis added].*[79]

According to the DRBC, there are no DRBC approved non-domestic wastewater treatment facilities in the Delaware River Basin at this time (**Exhibit 21**).[80] Absent DRBC review of exploration well permit applications, there is no process to limit the amount and type of waste generated at exploration wells in the Delaware River Basin, and there is no method to ensure that it is collected and shipped to a state approved waste treatment and storage facility outside of the Delaware River Basin, because PADEP is not providing this additional level of oversight and assurance. PADEP only assures that PADEP's standards are met, not incremental local standards.

Examples of significant wastes that could be generated by an exploration well includes drilling mud, cuttings and produced water. This is not an exhaustive list, but rather these drilling wastes are described in more detail below to highlight some of the more significant environmental concerns.

Drilling Muds & Drill Cuttings: Drilling muds are used to control the hydrostatic pressure in a wellbore.[81] The most common weighting agent used is barite. Barite can contain mercury and other heavy metals.

Drilling muds are not used in air drilling techniques; however, it must be assumed that drilling muds will be used, because there is no state statute in Pennsylvania limiting shale gas drilling to air drilling methods only, [82] and the PPCs provided for review include drilling mud.

U.S. Department of Energy studies show that barite contains mercury (1ppm-10ppm Hg, depending on its origin).[83] Mercury concentrations can be reduced by using thermal methods, leaching with dilute acids, or selecting barite with naturally occurring lower concentration levels of mercury.[84]

The U.S. Department of Interior estimates that 0.8 metric tons of mercury is discharged into the Gulf of Mexico (GOM) annually (1839 lb Hg/yr) from mud disposed from drilling operations.[85] This equates to approximately 1.69 lbs[86] of mercury per well for wells drilled to a total depth of approximately 12,000'.

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[79] Newfield Appalachia PA, LLC, Preparedness, Prevention and Contingency Plan (PPCP), May 2010, submitted with all its grandfathered wells.
[80] Muszynski, W.J., DRBC Manager Water Resources Management Branch, Presentation, DRBC Engagement in Natural Gas Exploration and Development, Marcellus Shale Meeting, January 19, 2010.
[81] DRN communication with HCLLC on October 23, 2010.
[82] While DRN reports that Newfield stated publically at a September 15, 2010 meeting that its wells use air drilling methods, Newfield's PPC documents plan for use of drilling muds, not air drilling. DRN reports that the top-hole section of some wells may be drilled with air, and the remaining section of the well drilled with mud.
[83] http://www.fossil.energy.gov, "Mercury Removal from Barite for the Oil Industry."
[84] http://www.fossil.energy.gov, "Mercury Removal from Barite for the Oil Industry."

Assuming that the top-hole of some of these wells is drilled using air drilling methods, an average wellbore length of 5,000' for the remaining section of the well is drilled with mud, and there is a lower barite use rate of 100 lbs/ft, to account for lower expected pressures, the mercury content in drilling mud is estimated at 0.5- 5.0 lbs[87] per well, depending on barite quality.

Drilling muds may also contain the heavy metal cadmium, leading the EPA to establish cadmium concentration limits in drilling muds.[88]

Drill cuttings can also contain Naturally Occurring Radioactive Material (NORM). Absent data to support otherwise, there is the potential for NORM content in drill cuttings in the Delaware River Basin. Gas shales are known to contain NORM in some regions. Shales can be heterogeneous and the NORM compositions can vary substantially. Recent studies on the Marcellus Shale in New York State acknowledge that drilling and production waste and equipment may contain NORM. The New York State Department of Environmental Conservation (NYSDEC) reports that the Marcellus Shale contains Uranium-238 and Radium-226, and that this NORM may be present in drill cuttings, produced water and stimulation treatment waste.[89] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[90] Radiation pathways can include external gamma radiation, injection, inhalation of particulates, and radon gas.[91] Therefore, exploration drill cuttings should be tested to determine NORM content and be disposed of accordingly at a licensed radioactive waste disposal facility. Other oil and gas states, such as Texas and Louisiana, have adopted stringent NORM regulations for E&P operations, including: occupational dose control, surveys, testing and monitoring, record keeping, signs and labeling, and treatment and disposal methods.

Best practice for managing drilling muds and cuttings includes the use of "closed loop tank systems," instead of a reserve pit, and transportation to an approved waste disposal facility. This avoids the impact of constructing a reserve pit and the potential for leakage into the environment.

Yet PADEP did not require the best practice of closed loop tank systems for these grandfathered wells. Instead, PADEP allows drilling muds and cuttings in Pennsylvania to be disposed of in a variety of methods, including subsurface injection into a disposal well, annular injection into the annulus[92] of a previously drilled well, burial on site in pits, or transportation to an offsite waste treatment and disposal facility. There is no assurance that exploration well waste handling will meet DRBC water protection standards. Because PADEP allows onsite burial of drilling cuttings and land spreading of other E&P wastes, we must assume that onsite burial may occur.

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[85] http://www.gomr.mms.gov/homepg/regulate/environ/Hg%20discharge%20estimate.pdf.
[86] (1,091 wells/yr drilled in GOM))* (12,038 ft/well)*(140 lbs barite/ft)*(1x10^{-6} Hg/g barite)= 1,839 lb Hg/yr. (1,839 lb/Hg)/(1,091 wells) = 1.69 lbs of mercury per well.
[87] 1ppm Hg in barite= (1 Marcellus well)* (5,000 ft/well)*(100 lbs barite/ft)*(1x10^{-6} Hg/g barite) = 0.5 lb Hg/well
10ppm Hg in barite= (1 Marcellus well)* (5,000 ft/well)*(100 lbs barite/ft)*(10x10^{-6} Hg/g barite) = 5.0 lb Hg/well
[88] U.S. Environmental Protection Agency, Development Document for Effluent Limitation Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-93-003, 1993.
[89] New York State, 2009 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, DSGEIS, p. 4-36.
[90] New York State, 2009 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, DSGEIS, p. 6-129.
[91] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[92] Annulus is the space between the wellbore and the casing.

The drilling permits issued by PADEP for the 11 grandfathered wells do not limit drilling method, do not set limits on drilling mud composition, and do not specify waste disposal method.

Produced Water Waste: Formation water (commonly referred to as "produced water") can be generated as a waste during exploration drilling and well testing operations. PADEP reports that air drilling operations can produce larger quantities of produced water than those wells drilled with mud.[93] Produced waters that are discharged to surface waters or lands of the US are regulated under the federal Clean Water Act, under a National Pollutant Discharge Elimination System (NPDES) permit. PADEP administers the NPDES program in Pennsylvania.[94]

The primary method for disposal of oil field wastewater in Pennsylvania is through pre-treatment facilities that clarify and filter the waste and dispose of it to surface water or sewage treatment plants.[95] A smaller amount of wastewater is disposed of into Class II injection wells.[96] Absent waste management plans for most of the grandfathered wells, it is unclear what the waste management plan is for produced water, because PADEP also allows produced water to be disposed of by land or road spreading, under some circumstances.

Produced water is typically rich in chloride, which enhances the solubility of other elements, including the radioactive element radium. This often makes produced water unsuitable for land application or surface water disposal, especially in sensitive areas such as the Delaware River Basin.[97]

Other states, such as Texas, require extensive produced water testing and specifically prohibit road spreading of waste containing NORM.[98] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[99]

Furthermore, EPA identified produced water pits as an outdated practice if produced water contains NORM. EPA reports that:

> *Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM[100] in the water will concentrate in the bottom sludges or residual salts of the ponds. **Thus the pond sediments pose a potential radiological health risk**....produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is*

93 PADEP Oil and Gas Manual Chapter 4, October 2001.
94 PADEP Oil and Gas Manual Chapter 2, October 2001.
95 Gaudlio, A.W., Paugh, L.O. (Range Resources) and Hayes, T.D. (Gas Technology Institute), Marcellus Shale Water Management Challenges in Pennsylvania, 2008.
96 The Underground Injection Control Program (UIC) of the federal Safe Drinking Water Act governs control of the injection of flowback and produced waters to ensure that injected waste is confined to the injection zone in a manner that does not contaminate fresh water bearing formations that may serve as Underground Sources of Drinking Water (USDW).
97 US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
98 Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.
99 Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.
100 TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

> *returned in the same or lower concentration to the formations from which it was derived [emphasis added].*[101]

Newfield's Preparedness, Prevention and Contingency (PPC) Plan states:

> ***Produced water will be removed periodically from the tanks at each wellsite and transported by a licensed residual waste hauler to a permitted disposal facility*** *[emphasis added].* [102]

Newfield does not specify who the waste hauler is, nor does it name the permitted disposal facility. Therefore, it is not possible to confirm whether this waste handling plan conforms to DRBC's requirements for waste from industrial operations in the Delaware River Basin.

Findings:

- Drilling waste can result in environmental harm if not properly managed.
- Because waste management plans were not available, it is unclear what the waste management plan is/was for most of the grandfathered wells.
- Reported waste handling concern at the Teeple and Mastoushek wells are strong indications that additional waste management oversight is needed.
- There is no assurance that a driller's waste management plan will meet DRBC's water protection requirements, because PADEP allows waste disposal methods that DRBC does not.
- Best waste management practices in other states do not allow onsite burial of drilling waste.
- The used of closed loop tank systems is a best practice, preferred over reserve pits and impoundments.
- Drilling waste can include Naturally Occurring Radioactive Material (NORM), mercury, cadmium and other heavy metals.

D.5.6. Stray gas migration associated with oil and gas wells can impact water supplies

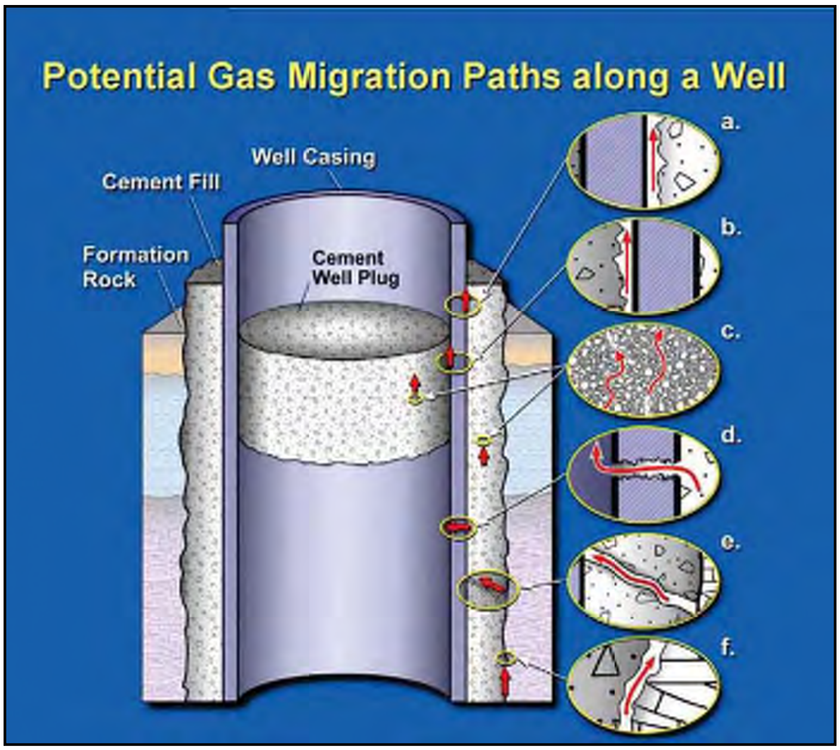
PADEP stresses the importance of proper well construction to mitigate stray gas, noting that these protections are not currently found in PADEP's regulations at Chapter 78, but will be when the rulemaking is finalized in 2011:

> ***Properly constructed and operated oil and gas wells are critical to protecting water supplies*** *and public safety.* ***If a well is not properly cased and cemented, natural gas in subsurface formations may potentially migrate from the wellbore through bedrock and soil. This stray gas may adversely affect water supplies****, as well as accumulate in or adjacent to structures such as residences and water wells. Under certain conditions,* ***stray gas has the potential to cause a fire or explosion. These situations present a serious threat to public health and safety as well as the***

[101] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.
[102] Newfield Appalachia PA, LLC, Preparedness, Prevention and Contingency Plan (PPCP), May 2010, submitted with all its grandfathered wells.

> ***environment.*** *The purpose of this final rulemaking is to improve drilling, casing, cement, testing, monitoring and plugging requirements for oil and gas wells to minimize gas migration and protect water supplies [emphasis added].*[103]

In October 2009, PADEP released a draft report summarizing 65 cases of stray natural gas migration associated with oil and gas wells (**Exhibit 32**), where improperly constructed and operated oil and gas wells have reportedly introduced gas into drinking water wells, aquifers, top soils, and structures. Most of these cases were attributed to inadequate well design and construction, improper well operation, poor well abandonment procedures, or a failure to abandon a well that is no longer in use.



The risks associated with well annulus over-pressuring, well casing failure, improperly constructed wells, and improperly abandoned wells could result in stray natural gas migration in the Delaware River Basin, if these risks are not mitigated.

There is insufficient information available on the grandfathered wells to verify whether the planned or installed casing and cementing configuration is a robust design. Therefore, it is not possible to verify whether stray gas problems associated with well construction practices have been mitigated in the grandfathered wells. Because there are no plug and abandonment applications or approvals for the grandfathered wells, it is not possible to verify whether the wells have been plugged or will be plugged in a manner that mitigates stray gas. Stray gas mitigation is a design concern for all types of well construction, including vertical and horizontal wells.

As shown in the figure above,[104] there are a number of ways that gas can migrate in a wellbore through failed piping (e.g. casing damage, corrosion, erosion) or through poor quality or improperly placed cement.

Open hole completions, where no cement or casing is installed across hydrocarbon bearing intervals, can increase the likelihood of gas migration.

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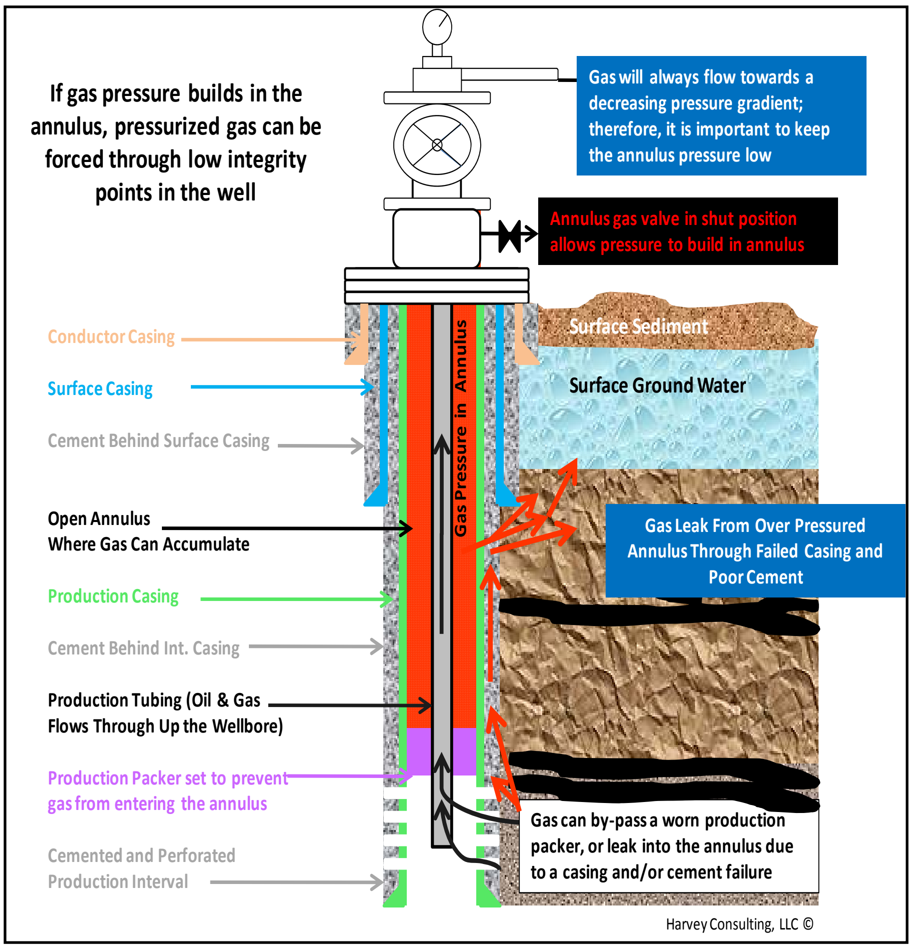
[103] PADEP Notice of Final Rulemaking, Department of Environmental Protection Environmental Quality Board, 25 Pa. Code, Chapter 78 Oil and Gas Well Cementing and Casing, 2010 (**Exhibit 30A**).
[104] Potential Gas Migration Pathways Diagram, Alberta Energy Utilities Board.

Unmonitored annulus pressure in completed, temporarily suspended wells can also provide opportunities for stray gas problems. Over pressured well annulus (see diagrams on next pages) can force gas through low integrity points in the well.

For the grandfathered wells that have been drilled, but not yet plugged, it is important that the well is monitored to ensure that the annulus does not over-pressure, forcing high pressure gas from the well annulus into lower pressure ground water zones. This happens under certain circumstances, such as when a wellbore is not cased and cemented; casing failure occurs; cement is poorly bonded; or a production packer fails.

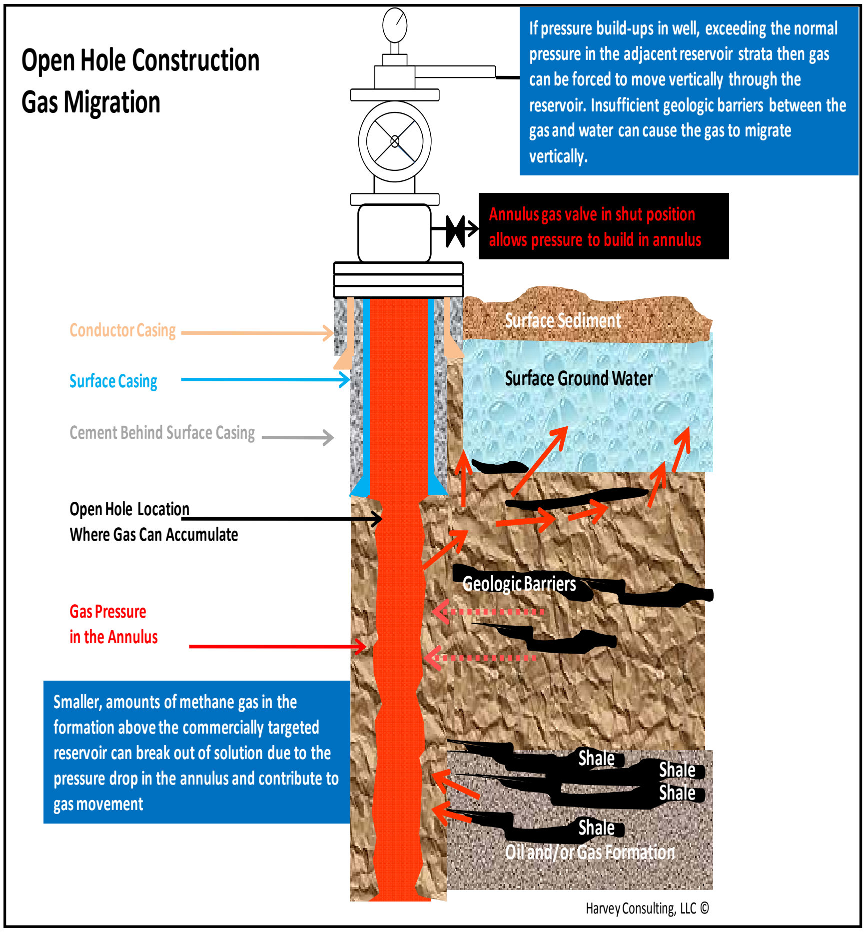
The diagrams shown in this report are simplified schematics showing the risk posed by gas migration due to annular over-pressuring (in a completed well) or a well that is left open hole (uncased) and uncompleted. These diagrams are not intended to show how the grandfathered wells may have been constructed, because those construction diagrams were not available for my review. Rather these diagrams are intended to show the types of stray gas problems that can occur in cased and completed wells, and in open hole completions.



New construction practices do not guarantee stray gas migration will not occur, but these practices do significantly reduce risk. Over time production packers can wear out or casing can fail due to corrosive and erosive conditions in the wellbore, resulting in gas leaks into the annular space. Poor cementing practices can also result in gas movement.

Proper monitoring of the annulus pressure can help prevent gas migration. Even in wells constructed with more modern well construction techniques, gas pressure can build in the annulus. For example, gas can bypass a worn out production packer or leak into the annulus due to a casing and/or cement failure. Gas from a higher pressure oil and gas formation will move into the annulus through a leak because the annulus is of lower pressure. By the laws of physics, gas will always flow toward a decreasing pressure gradient. Therefore, the higher pressure gas will move from the oil and gas reservoir into the lower pressure annulus. As long as the annulus is not over pressured, this gas can be extracted at the surface. However, if the annulus becomes over pressured, formation gas will take the path of least resistance, which may cause it to migrate into shallower formations.

An open-hole provides several pathways for gas to migrate from deeper, higher pressure formations to shallower, lower pressure formations. Gas can leak though poor cement placed at the bottom of the production casing. Smaller amounts of methane gas in the formation above the commercially targeted reservoir can break out of solution, and move toward the lower pressure open-annulus. An over-pressured annulus can cause gas to move from the higher pressure annulus into lower pressure, shallower zones.



The problem of ground water contamination by open-hole completions in Pennsylvania is well documented in two articles published in the Ground Water Journal by Samuel Harrison, a Professor of Geology and Environmental Science from Allegheny College, Meadville, Pennsylvania.[105,106]

Dr. Harrison concluded:

> *This annulus is a potential avenue of migration of contaminants from strata of higher hydrodynamic pressure into formations of lower hydrodynamic pressure.* ***<u>If gas from the strata exposed to the annulus is not permitted to escape to the atmosphere, the annulus may become pressurized and a hydraulic gradient may be created between the potential contaminants in the annulus (e.g. brine and/or natural gas) and the overlying fresh-water aquifers.</u>*** *If a permeability pathway exists between the pressurized annulus and an overlying fresh-water aquifer,* ***<u>contamination of the aquifer will result</u>*** *[emphasis added].”*[107]

Of note, Dr. Harrison’s article from 1985 stated that gas should be vented to atmosphere to relieve pressure on the annulus. However, best practices to mitigate greenhouse gas emissions, such as methane,

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[105] Harrison, S.S., Evaluating System for Ground-Water Contamination Hazards Due to Gas-Well Drilling on Glaciated Appalachian Plateau, Groundwater, November-December 1983, Vol. 21, No.6.
[106] Harrison, S.S., Contamination of Aquifers by Overpressuring the Annulus of Oil and Gas Wells, Groundwater, May-June 1985, Vol. 23, No.3.
[107] Harrison, S.S., Evaluating System for Ground-Water Contamination Hazards Due to Gas-Well Drilling on Glaciated Appalachian Plateau, Groundwater, November-December 1983, Vol. 21, No.6.

now recommend collecting this gas in a low pressure gas system or using it as fuel at the well site, rather than venting it to atmosphere, where technically feasible.

Dr. Harrison goes on to write:

> *The risk of contaminating fresh ground water with the contents of a gas- or oil-well annulus could be greatly reduced by filling the annulus with cement.*

The oil and gas industry has learned from experience that casing and cementing the wells along the entire length of the hole provides added protection to ground water resources, as shown in the more current wellbore construction approaches used today.

Gas pressure buildup in the annulus can cause gas to move vertically in the reservoir toward the lower pressure ground water aquifer. This problem can be mitigated by opening the annulus valve and producing the gas to the surface, thereby decreasing the pressure in the annulus ("gas annulus de-pressuring"). An open-hole design does not guarantee that gas will migrate vertically to the lower pressure groundwater aquifer. It is just more likely to occur than in a more robust well construction design, with multiple barriers of cement and casing.

Geologic barriers to vertical flow, such as thick continuous shale layers, can trap gas and prevent vertical migration. Sealed faults and other sealed geologic unconformities can also provide barriers to vertical flow. Moreover, the pressure of the gas in the annulus must exceed the normal hydrostatic pressure gradient for it to flow vertically. Higher pressure gas will naturally seek equilibrium pressure and flow toward areas of lower pressure. If the gas pressure is sufficient enough to overcome the natural hydrostatic pressure gradient, and there are insufficient geologic barriers to prevent vertical gas migration, then gas may reach the ground water reservoir.

Pennsylvania has casing pressure regulations at Subchapter D, § 78.73 requiring Operators to monitor and prevent gas well annulus over-pressuring. The fact that gas well annulus over-pressuring is occurring, despite this rule being in place points to the need for additional agency monitoring and oversight to ensure the regulation is being complied with in the field.

Findings:

- Stray gas migration associated with oil and gas wells can impact water supplies.
- Well construction improvements to mitigate stray gas problems associated with oil and gas drilling have been proposed by PADEP for adoption in 2011, but will not apply to most of the grandfathered wells.
- Risks associated with well annulus over-pressuring, well casing failure, improperly constructed wells and improperly abandoned wells could result in stray natural gas migration in the Delaware River Basin, if these risks are not mitigated.
- Because there are no plug and abandonment applications or approvals for the grandfathered wells, it is not possible to verify whether the wells have been plugged or will be plugged in a manner that mitigates stray gas.
- Open hole completions and/or unmonitored annulus pressure in completed, temporarily suspended wells can provide opportunities for stray gas problems.

D.5.7. PADEP's well siting criteria allow wells to be placed very close to water resources

The Oil and Gas Act, §601.205(a) only requires oil and gas wells be located at least 200 feet from existing buildings and existing water wells, and allows for granting a variance[108] to place the well even closer.

The Oil and Gas Act, §601.205(b) only requires oil and gas wells be located at least 100 feet from any stream, spring or body of water, as identified on the most current 7½ minute topographic map, and at least 100 feet from any wetland greater than one acre in size, and allows for granting a variance[109] to place the well even closer.

These surface siting criteria do not provide sufficient setbacks from sensitive water resources in the Delaware River Basin. For example, blowouts can eject drilling mud, gas, oil and/or formation water from the well and onto waters and lands adjacent to the well, within the radius of the blowout plume. Depending on the reservoir pressure, blowout circumstances, and wind speed these pollutants can be distributed hundreds to thousands of feet away from the well.[110] Pressurized fluids can spray hundreds of feet, and spilled fluids can travel across surface terrain, or seep into the ground and travel towards water resources though the soil. For example, in September 2009 well chemicals spilled at the Cabot Heitsman 4H well flowed to the nearby Steven's Creeks located more than 100' away.[111]

The Crum well site is on the North Branch of Calkins Creek, a "High Quality" Creek, as classified by PADEP. It has high quality biota in the stream that will be impacted by influxes of sediment and pollution, and changes in stream flow. Calkins Creek supports brook trout, brown trout (both are temperature sensitive), merganser ducks, and great blue herons. It is also habitat for black bear and bald eagles that fish the river and roost the forest in this sub-watershed.[112] The Woodland well site is less than one-half mile from the river, on Hollister Creek, a "High Quality" stream, as classified by PADEP. Black bear and bald eagles use this area for hunting, foraging and nesting.

Findings:

- PADEP's setback requirements of 100' from a water body or 200' from a well are not sufficient to protect high-value water resources.

D.5.8 Air pollution impacts are not well understood or mitigated.

The 25 PA Code § 127.14 (38) exempts oil and gas drilling operations from air quality control requirements (**Exhibit 33**).

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108 Where the restriction would deprive the owner of the oil and gas rights, the right to produce or share in production, the Department may grant a variance upon submission and approval of form 5500-FM-OG0058, Request for Variance From Distance Restriction From Existing Building or Water Supply.

109 The Department may waive distance requirements upon submission and approval of form 5500-FM-OG0057, Request for Waiver for Distance Requirements From Springs, Streams, Body of Water or Wetland.

110 S.L. Ross Environmental Research Limited, Oil Deposition Modeling For Surface Oil Well Blowouts, 1998.

111 Cabot Oil & Gas Corporation, Engineering Study, Prepared for PADEP, In Response to Order Dated September 24, 2009, prepared by URS Corporation for Cabot, October 9, 2009.

112 Biological Information provided by DRN November 1, 2010.

"38. Oil and gas exploration and production facilities and operations that include wells and associated equipment and processes used either to: a) drill or alter oil and gas wells; b) extract, process and deliver crude oil and natural gas to the point of lease custody transfer; c) plug abandoned wells and restore well sites, or d) treat and dispose of associated wastes. This includes petroleum liquid storage tanks which are used to store produced crude oil and condensate prior to lease custody transfer."

This exemption includes shale gas drilling; therefore, air pollution impacts from the grandfathered wells are currently unregulated and unmitigated.

PADEP is in the process of determining whether this air permitting exemption is warranted for Marcellus Shale Drilling Operations. PADEP is currently studying short-term air quality impacts and is expected to complete these studies in early 2011 (**Exhibit 33** includes a news report summarizing PADEP's study).

PADEP's study does not examine combined and cumulative impacts of multiple drilling operations, nor does PADEP's study examine the impacts of air pollutant transport and deposition on waters and lands downwind of drilling operations.

Components of atmosphere pollution caused by exploration drilling includes gaseous products of hydrocarbon evaporation and burning as well as aerosol particles of unburned fuel, including nitrogen oxide, sulfur oxides, carbon monoxide, particulate matter, and hazardous air pollutants. These airborne pollutants interact with atmospheric moisture, and transform in the presence of solar radiation and precipitate onto land and water surfaces causing both local and regional pollution.[113]

There are a number of potential air emission sources from drilling operations, including combustion source emissions (drilling engines and flares), direct venting of gas, and fugitive emissions from pits, impoundments and other leaks.

Since PADEP does not require a permit and there is no list of emission sources, or any assessment of the air pollution impact, it is not clear whether air pollution impacts from the grandfathered wells are significant and warrant mitigation to protect the Delaware River Basin airshed and associated waters. Air pollution can transport airborne pollutants downwind, depositing pollutants to water and land surfaces. These impacts are not well understood or mitigated for the grandfathered wells.

EPA explains the direct relationship between air pollution and water quality impacts:

Airborne pollutants *from human and natural sources* ***can deposit back onto*** *land and* ***water bodies, sometimes at great distances from the source, and can be an important contributor to declining water quality.*** *Pollutants in waterbodies that may originate in part from atmospheric sources include nitrogen compounds, sulfur compounds, mercury, pesticides, and other toxics [emphasis added]."*[114]

Airborne pollution can fall to the ground in precipitation, in dust, or simply due to gravity. This type of pollution is called "atmospheric deposition" or "air deposition." Pollution deposited from the air can reach water bodies in two ways. It can either be deposited directly onto the surface of the water (direct deposition) or be deposited onto land and be carried to water bodies

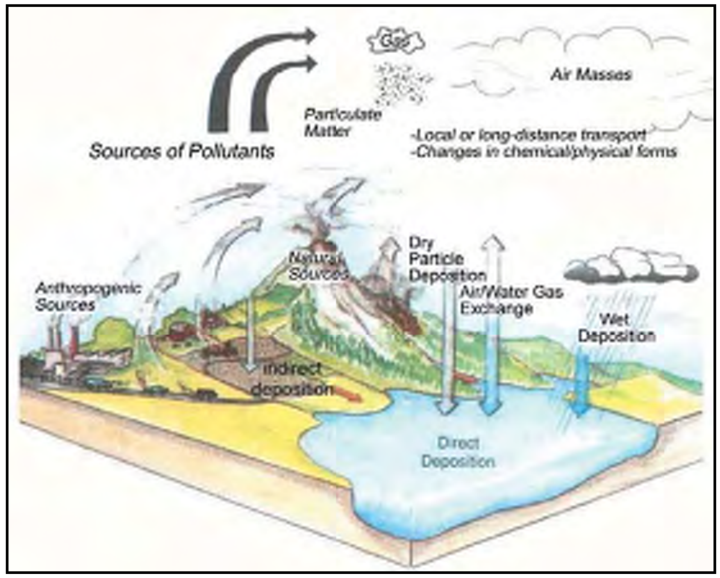
[113] Rana, S., Facts and Data on Environmental Risks- Oil and Gas Drilling Operations, Society of Petroleum Engineering Paper 114993, October 2008.
[114] http://water.epa.gov/lawsregs/lawsguidance/cwa/tmdl/airdeposition_index.cfm

> *through run off (indirect deposition).* ***Once these pollutants are in the water, they can have undesirable health and environmental impacts, such as contaminated fish, harmful algal blooms, and unsafe drinking water*** *[emphasis added].*[115]

The diagram below shows the air pollution pathway from industrial sources to water resources.[116]

EPA explains that there are several pathways for air pollution to contaminate water resources, including:

- Direct deposition where air pollutants are directly deposited to the water resource;
- Indirect deposition where the air pollutant is deposited to the water resource, initially only impacting one part of the water resource, but later those pollutants are transported through runoff, rivers, streams and groundwater contaminating larger areas;
- Wet deposition where pollutants are deposited in rain, snow clouds or fog. Acid rain is an example of wet deposition of sulfur and nitrogen compounds associated with fossil fuel combustion;



- Dry deposition where air pollutant particles settle on water surfaces via gravity.

In many states, drilling equipment has been exempt from air permitting requirements because of its mobile, short-term nature, but upon further study regulators are finding that the air pollution impacts are more substantial than initially expected especially the amount of hazardous air pollution that is emitted, when large open-air impoundments are used to store fracture fluids and drilling chemicals.

A recent Environmental Impact Statement completed for Marcellus Shale drilling in New York State identified the potential for large amounts of hazardous air pollution (methanol[117]) may be present at central impoundments (32.5 tons per year).[118] A major source of hazardous air pollution is one that emits more than 10 tons/yr of any single hazardous air pollutant, or 25 tons/yr of multiple hazardous air pollutants, therefore New York's study found that shale drilling operations exceeded the hazardous pollutant threshold by more than three times.

[115] http://water.epa.gov/lawsregs/lawsguidance/cwa/tmdl/airdeposition_index.cfm
[116] EPA's Office of Air and Radiation (OAR) and Office of Water (OW), Frequently Asked Questions about Atmospheric Deposition Handbook: A Handbook for Watershed Managers, EPA-453/R-01-009, September 2001.
[117] EPA lists methanol as a hazardous air pollutant, but has not yet classified methanol with respect to carcinogenicity. http://www.epa.gov/ttn/atw/hlthef/methanol.html. Chronic inhalation or oral exposure may result in headache, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness in humans. Neurological damage, specifically permanent motor dysfunction, may also result. The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.
[118] New York State, 2009 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, DSGEIS, p. 6-57.

The New York State Environmental Impact Statement did not estimate significant amounts of benzene emissions; however, recent reports indicate the Texas Commission on Environmental Quality is finding surprisingly high levels of benzene emitted from Barnett Gas Shale activities in Texas.[119] Benzene is a known, EPA-listed human carcinogen.

Air toxics do not just remain airborne when emitted from industrial operations, these toxins can deposit onto soils or surface waters where they are taken up by plants and ingested by animals and can be magnified through the food chain.[120]

Findings:

- PADEP exempts oil shale gas drilling operations from air quality control requirements, but has yet to complete a study to verify that short and long-term (cumulative impacts) meet the Clean Air Act requirements and are protective of human health and the environment.
- PADEP is in the process of determining whether this air permitting exemption is warranted for Marcellus Shale Drilling Operations. PADEP is currently studying short-term air quality impacts and is expected to complete these studies in early 2011.
- PADEP's study does not examine combined and cumulative impacts of multiple drilling operations, nor does it examine the impacts of air pollutant transport and deposition on waters and lands downwind of drilling operations.
- Shale gas drilling operations, when combined with use of fracture and drilling chemical impoundments, can be major sources of hazardous air pollutants.
- The use of closed looped collection and tank systems can mitigate water, land and air pollution impacts and are best pollution mitigation practices for shale gas drilling.
- Fuel and power selection options can also be considered to reduce air pollution impacts.

[119] Dr. Michael Honeycutt, Head of TCEQ's Toxicology Division, quoted in WFAA-TV new report, November 20, 2009. Dr. Michael Honeycutt "was shocked to see air sampling revealed high levels of benzene, a cancer-causing toxin, near some natural gas facilities."
[120] http://www.epa.gov/oar/toxicair/newtoxics.html