

RULES AND REGULATIONS

Title 25—ENVIRONMENTAL PROTECTION

ENVIRONMENTAL QUALITY BOARD

[25 PA. CODE CHS. 78 AND 78a]

Environmental Protection Performance Standards at Oil and Gas Well Sites

The Environmental Quality Board (Board) amends Chapter 78 (relating to oil and gas wells) and adds Chapter 78a (relating to unconventional wells) to read as set forth in Annex A. This final-form rulemaking relates to surface activities associated with the development of unconventional wells. The goal of this final-form rulemaking is to set performance standards for surface activities associated with the development of unconventional wells and to prevent and minimize spills and releases to the environment to ensure protection of the waters of the Commonwealth, public health and safety, and the environment.

This final-form rulemaking represents the first update to rules governing surface activities associated with the development of unconventional wells. This final-form rulemaking adds Chapter 78a to establish the requirements for unconventional well development and amends Chapter 78 to delete any conflicting requirements that remained in that chapter for unconventional wells.

Major areas of this final-form rulemaking in Chapter 78a include public resource impact screening, water supply replacement standards, waste management and disposal, and establishing identification and select monitoring of wells located proximal to hydraulic fracturing activities. Other new regulations include standards for well development impoundments, a process for the closure or waste permitting for wastewater impoundments, onsite wastewater processing, site restoration, standards for borrow pits, and reporting and remediating spills and releases.

Chapter 78a also contains requirements for the containment of regulated substances, oil and gas gathering pipelines, well development pipelines and water management plans (WMP).

On February 3, 2016, the Board adopted the pre-Act 52 regulations containing two separate chapters—one for conventional oil and gas wells (Chapter 78) and the other for unconventional wells (Chapter 78a).

The Department of Environmental Protection (Department) delivered the pre-Act 52 final-form regulations to IRRC and the House and Senate Environmental Resources and Energy Committees on March 3, 2016. On April 12, 2016, the House and Senate Environmental Resources and Energy Committees voted to disapprove the pre-Act 52 final-form regulations and notified IRRC and the Board. On April 21, 2016, IRRC held a public hearing to consider the pre-Act 52 final-form regulations and approved it in a 3-2 vote. On May 3, 2016, the House Environmental Resources and Energy Committee voted to report a concurrent resolution to disapprove the pre-Act 52 final-form regulations approved by IRRC to the General Assembly. The concurrent resolution was not passed by the General Assembly within 30 calendar days or 10 legislative days from the reporting of the concurrent resolution.

The act of June 23, 2016 (P.L. 379, No. 52 (Act 52)) abrogated the pre-Act 52 final-form regulations “insofar as such regulations pertain to conventional oil and gas wells.”

The Department delivered the pre-Act 52 final-form regulations to the Office of Attorney General for form and legality review on June 27, 2016. In accordance with the Regulatory Review Act (71 P.S. §§ 745.1—745.14) and the Commonwealth Attorneys Act (71 P.S. §§ 732-101—732-506), the Office of Attorney General directed the Department to make changes to the pre-Act 52 final-form regulations to comply with Act 52. Specifically, the Office of Attorney General directed the Department to comply with Act 52 by removing all amendments or additions to the final-form regulations in Chapter 78 regarding conventional oil and gas wells prior to resubmission to the Office of Attorney General for review. Additionally, the Office of Attorney General directed the Department to retain all deletions and modifications within the pre-Act 52 final-form regulations of Chapter 78 that related to the unconventional oil and gas industry and to ensure that the requirements in the final-form rulemaking in Chapter 78a supersede any conflicting requirements in Chapter 78. The Office of Attorney General also objected to several typographical errors and sought corrections and clarifications to the following provisions: the definition of “mine influenced water” in § 78a.1 (relating to definitions) and §§ 78a.13(a), 78a.17(b), 78a.65(b)(8), 78a.67(c)(2), 78a.75(a), 78a.75a(a), 78a.83(a)(2), 78a.83b(a)(1), 78a.87(b), 78a.88(c), (d), (d)(1) and (2), 78a.91(a) and 78a.101.

On July 26, 2016, the Department resubmitted this final-form rulemaking to the Office of Attorney General for review. In accordance with the Office of Attorney General’s direction, the Department removed all amendments or additions to Chapter 78 regarding conventional oil and gas wells and retained the deletions and modifications in Chapter 78 that related solely to the unconventional wells. This revised final-form rulemaking also contains clarifications and corrections to respond to other issues identified by the Office of Attorney General, including the addition of § 78a.2 (relating to applicability) to clarify that Chapter 78a supersedes Chapter 78 for unconventional wells to avoid any potential conflict between the requirements in Chapter 78 and Chapter 78a regarding unconventional wells. Later on July 26, 2016, the Office of Attorney General approved this revised final-form rulemaking for form and legality under the Commonwealth Attorneys Act. The final-form rulemaking in Annex A is the revised final-form rulemaking as approved by the Office of Attorney General. This preamble was revised to reflect the final-form rulemaking as approved by the Office of Attorney General in conformance with Act 52.

The Joint Committee on Documents met on August 18, 2016, and voted to direct the Legislative Reference Bureau (Bureau) to publish this final-form rulemaking.

A. *Effective Date*

This final-form rulemaking will be effective upon publication in the *Pennsylvania Bulletin*.

B. *Contact Persons*

For further information, contact Kurt Klapkowski, Director, Bureau of Oil and Gas Planning and Program Management, Rachel Carson State Office Building, 15th

Floor, 400 Market Street, P.O. Box 8765, Harrisburg, PA 17105-8765, (717) 772-2199; or Elizabeth Davis, Assistant Counsel, Bureau of Regulatory Counsel, P.O. Box 8464, Rachel Carson State Office Building, Harrisburg, PA 17105-8464, (717) 787-7060. Persons with a disability may use the Pennsylvania AT&T Relay Service, (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This final-form rulemaking is available on the Department's web site at www.dep.pa.gov (select "Public Participation," then "Environmental Quality Board (EQB)").

C. *Statutory Authority*

This final-form rulemaking is being made under the authority of 58 Pa.C.S. §§ 3202, 3215(e), 3218(a), 3218.2(a)(4), 3218.4(c) and 3274, section 5 of The Clean Streams Law (35 P.S. § 691.5), section 105 of the Solid Waste Management Act (SWMA) (35 P.S. § 6018.105), section 5 of the Dam Safety and Encroachments Act (32 P.S. § 693.5), section 104 of the Land Recycling and Environmental Remediation Standards Act (Act 2) (35 P.S. § 6026.104), sections 301 and 302 of the Radiation Protection Act (35 P.S. §§ 7110.301 and 7110.302), section 3 of the Unconventional Well Report Act (58 P.S. § 1003), section 13.2 of the act of July 10, 2014 (P.L. 1053, No. 126) (Act 126) adding section 1741.1-E of The Fiscal Code (72 P.S. § 1741.1-E) and sections 1917-A and 1920-A of The Administrative Code of 1929 (71 P.S. §§ 510-17 and 510-20).

D. *Background and Summary*

This final-form rulemaking amends the oil and gas well regulations and adds additional controls to the surface activities associated with the development of unconventional well sites.

This final-form rulemaking is needed to ensure that surface activities regarding the development of unconventional wells are conducted in a manner that protects the health, safety and environment of citizens in this Commonwealth consistent with the environmental laws that provide authority for this final-form rulemaking. The surface activities requirements in Chapter 78, Subchapter C (relating to environmental protection performance standards) were last updated in 2001, prior to the significant expansion of natural gas development utilizing enhanced drilling techniques to target the Marcellus Shale formation. This final-form rulemaking is needed for several specific reasons, including: (1) statutory changes and new environmental protection standards for unconventional wells resulting from the passage of 58 Pa.C.S. Chapter 32 (relating to development) (2012 Oil and Gas Act) including: direction to promulgate specific regulations; (2) new technologies associated with extracting natural gas from unconventional formations; (3) changes in the Department's other regulatory programs; (4) environmental protection gaps in the Department's existing regulatory program currently addressed through policy or other means; and (5) recommendations from State Review of Oil and Natural Gas Environmental Regulations (STRONGER) regarding the potential risk of hydraulic fracturing communication.

Because unconventional well drilling occurs in over 60% of this Commonwealth and pipeline activities occur throughout this entire Commonwealth, all of its citizens will benefit from more robust and comprehensive regulations. The regulated community will benefit from this final-form rulemaking because it streamlines authorizations and approval processes and establishes performance based requirements that will avoid or minimize environmental impacts which can be costly to remediate. Many of

the environmental performance standards in this final-form rulemaking are either a codification of current statutory or permit requirements, or are already standard industry practices. As a whole, this final-form rulemaking will strengthen measures aimed at reducing the potential impacts that oil and gas activities may have on the environment.

The Department also notes that there are several areas in this final-form rulemaking where current policies and practices are codified into regulation. This should provide significant benefits for several reasons. First, by having these policies expressed in regulation, all parties—the public, unconventional operators, Department staff, service companies, and the like—will be able to have a transparent, up-front, black-and-white understanding of the standards of performance that apply to oil and gas development in this Commonwealth. Having these policies and practices codified into Chapter 78a will establish binding norms as regulations have the force and effect of law and enjoy a general presumption of reasonableness. When a policy or practice has been in effect for a significant amount of time, it may be appropriate to move to codify it into regulation. Significant examples of these subjects abound in this final-form rulemaking:

- Section 78a.17(a) (relating to permit expiration and renewal), which codifies the Department's interpretation of the phrase "pursued with due diligence" in section 3211(i) of the 2012 Oil and Gas Act (relating to well permits).

- Section 78a.51 (relating to protection of water supplies), which codifies the Department's interpretation of water supply replacement quality standards under section 3218(a) of the 2012 Oil and Gas Act (relating to protection of water supplies).

- Section 78a.55 (relating to control and disposal planning; emergency response for unconventional wells), which codifies the Department's current position regarding the development and maintenance of Preparedness, Prevention and Contingency (PPC) plans for well sites.

- Sections 78a.56 and 78a.57 (relating to temporary storage; and control, storage and disposal of production fluids), which codify the Department's current policies regarding management of waste on unconventional well sites and the interpretation of section 3273.1(a) of the 2012 Oil and Gas Act (relating to relationship to solid waste and surface mining).

- Section 78a.58 (relating to onsite processing), which codifies the Department's current approval process for onsite waste processing.

- Section 78a.59c (relating to centralized impoundments), which codifies the Department's position regarding the proper regulation of offsite waste management operations.

- Section 78a.65 (relating to site restoration), which codifies the Department's positions regarding well site restoration under Chapter 102 (relating to erosion and sediment control) and section 3216 of the 2012 Oil and Gas Act (relating to well site restoration).

- Section 78a.66 (relating to reporting and remediating spills and releases), which codifies the Department's interpretation of existing requirements for reporting and remediating releases.

- Section 78a.67 (relating to borrow pits), which codifies the Department's interpretation of the borrow pit exemption outlined in section 3273.1(b) of the 2012 Oil and Gas Act.

- Section 78a.122 (relating to well record and completion report), which codifies the Department's current well record and completion report requirements in accordance with section 3222 of the 2012 Oil and Gas Act (relating to well reporting requirements) and section 3 of the Unconventional Well Reporting Act.

Having these policies, practices, interpretations and procedures codified into regulations in a single location—as opposed to scattered throughout factsheets, application and approval forms and instructions, statements of policy and technical guidance documents, Department letters and webpages—will provide transparency and allow all parties to understand the requirements that apply to this industry.

Bifurcation

As part of this final-form rulemaking, in response to comments and Act 126, the Department split Chapter 78 into two separate chapters—one for conventional oil and gas wells (Chapter 78) and the other for unconventional wells (Chapter 78a). The purpose of this bifurcation was to clarify the different requirements for conventional and unconventional wells. The Department believes that having two completely separate chapters should serve to eliminate any confusion about what requirements apply to conventional and unconventional wells. In addition, having separate chapters allows the Department to craft regulations to match the environmental risks posed by each segment of the industry (compare, for example, § 78.56 (relating to pits and tanks for temporary containment) and § 78a.56, which contain significantly different requirements for temporary storage at conventional and unconventional well sites, respectively). To clearly summarize these regulations, the Department will discuss each chapter in Sections E and F.

(Department Note: All amendments or additions to Chapter 78 regarding conventional oil and gas wells were removed from this final-form rulemaking in accordance with the direction of the Office of Attorney General to comply with Act 52. The amendments in Chapter 78 are limited to deletions of the provisions regarding unconventional wells.)

Public outreach

The Department engaged in significant discourse with the Oil and Gas Technical Advisory Board (TAB) and other groups during the development of the proposed and final-form rulemakings. The initial public discussion of what became this final-form rulemaking occurred at TAB's January 21, 2010, meeting, where the Department presented an overview of subjects to be addressed in this final-form rulemaking. At TAB's April 12, 2011, and October 21, 2011, meetings, the Department again discussed topics to be included in this final-form rulemaking as well as providing TAB with updates on the Department's development of the draft proposed rulemaking.

On February 16, 2012, the Department presented TAB with a detailed conceptual summary of the proposed amendments addressing surface activities to Chapter 78. After the enactment of the 2012 Oil and Gas Act, this detailed summary was revised and discussed again with TAB on August 15, 2012.

The Department met with other industry representative groups on several occasions during the development of the draft proposed rulemaking, including: the Marcellus Shale Coalition, which is mostly comprised of businesses representing unconventional drillers; the Pennsylvania Independent Oil and Gas Association, which represents unconventional and conventional drillers; and

Pennsylvania Independent Petroleum Producers, which represents conventional oil industry, the Pennsylvania chapter of the American Petroleum Institute, and individual operators and midstream companies. In addition, the Department held regular meetings with industry representatives quarterly throughout the entire pendency of this final-form rulemaking. This final-form rulemaking generally and specific individual topics addressed by this final-form rulemaking were standard agenda items at these meetings.

Local government organizations were also involved in discussions of the proposed rulemaking, including then-Lycoming County Commissioner Jeff C. Wheeland, the Pennsylvania State Association of Township Supervisors and the Pennsylvania State Association of Boroughs.

The Department also involved several environmental organizations in the development of the proposed rulemaking, including the Chesapeake Bay Foundation, the Western Pennsylvania Conservancy, The Nature Conservancy and the Pennsylvania Environmental Council. In addition, the Department held regular meetings with environmental organization representatives (including Clean Water Action and the Delaware Riverkeeper) quarterly throughout the entire pendency of this final-form rulemaking. This final-form rulemaking generally and specific individual topics addressed by this final-form rulemaking were standard agenda items at these meetings.

The Department also consulted with other State agencies during the development of the proposed and draft final-form regulations, including the Department of Transportation, the Department of Conservation and Natural Resources, the Fish and Boat Commission, the Game Commission and the Pennsylvania Historical and Museum Commission.

A draft of the proposed rulemaking was shared with TAB members in December 2012, and a revised version of the draft proposed rulemaking was discussed at the TAB meeting on February 20, 2013. In response to TAB's comments, the Department again revised the draft proposed rulemaking and presented it to TAB on April 23, 2013, for formal consideration. At the April 23, 2013, meeting, TAB voted unanimously, with one member absent, to recommend that the Board publish the proposed rulemaking for public comment.

Following the April 2013 TAB meeting, the Department continued discussions on the topics in the proposed rulemaking at TAB's June 12, 2013, meeting. At that meeting, TAB subcommittees were established and future meetings scheduled. On two occasions, those TAB subcommittees met to consider public resource impact permit screening, water supply replacement, the general topic of waste management and the area of review requirements—July 17 and 18, 2013 (Greensburg, PA) and August 14 and 15, 2013 (State College, PA). Participants in those meetings included associations representing the conventional and unconventional industries, consultants, attorneys, environmental groups and members of the public.

Following publication of the proposed rulemaking at 43 Pa.B. 7377 (December 14, 2013) for public comment and the close of the 90-day public comment period, the Department discussed the comments received as well as the draft final-form regulations with TAB at its June 26, 2014, meeting. At the September 25, 2014, TAB meeting, the Department discussed splitting the regulations into two individual chapters and significant changes to the

regulations, especially to the extent those changes concerned conventional operators.

In terms of this final-form rulemaking, the Department discussed the draft final-form regulations announced under the Advanced Notice of Final Rulemaking (ANFR) process with TAB at meetings on March 20, 2015, and April 23, 2015. Following the close of the ANFR public comment period, the Department released the pre-Act 52 final-form regulations, which it discussed with TAB on September 2, 2015. TAB suggested changes to that document, so the Department considered those requests and further amended the pre-Act 52 final-form regulations and discussed those changes with TAB members during a webinar held on September 18, 2015. Additional changes to the pre-Act 52 regulations resulted from suggestions made during that webinar. The Department presented the pre-Act 52 final-form regulations to TAB at its October 27, 2015, meeting. On October 27, 2015, TAB voted unanimously to move the pre-Act 52 final-form regulations to the Board without expressing support or disapproval and indicated they would be presenting a report on the pre-Act 52 final-form regulations to the Board. On January 6, 2016, TAB submitted a report on the pre-Act 52 final-form regulations to the Board. A copy of this report is available on the Department's web site or from the contact persons listed in Section B.

The Department also discussed the draft final-form regulations with the Conventional Oil and Gas Advisory Committee (COGAC) in 2015. The Department formed COGAC in March 2015 to have an advisory body that was focused solely on the issues confronting the conventional oil and gas industry. The Department discussed the comments received on the proposed rulemaking and the ANFR final-form regulations with COGAC on March 26, 2015. Following the close of the ANFR public comment period, the Department released the pre-Act 52 final-form regulations, which it discussed with COGAC on August 27, 2015. COGAC suggested changes to that document, so the Department considered those requests and further amended the pre-Act 52 final-form regulations and discussed those changes with COGAC members during a webinar held on September 18, 2015. Additional changes to the draft pre-Act 52 final-form regulations resulted from suggestions made during that webinar. The Department presented the pre-Act 52 final-form regulations to COGAC at its October 29, 2015, meeting. At that meeting, COGAC adopted a resolution recommending the Board disapproval of the pre-Act 52 final-form regulations as it applied to conventional operators. At a meeting on December 22, 2015, COGAC adopted comments to the Board on the pre-Act 52 final-form regulations urging disapproval. A copy of that document is available on the Department's web site or from the contact persons listed in Section B.

On January 6, 2016, the Department submitted the pre-Act 52 final-form regulations to the Board for review and consideration. At its meeting on February 3, 2016, the Board approved the pre-Act 52 regulations by a vote of 15-4. The Department delivered the pre-Act 52 final-form regulations to IRRC and the House and Senate Environmental Resources and Energy Committees on March 3, 2016. On April 12, 2016, the House and Senate Environmental Resources and Energy Committees voted to disapprove the pre-Act 52 final-form regulations and notified IRRC and the Board. On April 21, 2016, IRRC held a public hearing to consider the pre-Act 52 regulations and approved it in a 3-2 vote. On May 3, 2016, the House Environmental Resources and Energy Committee voted to report a concurrent resolution to disapprove the

pre-Act 52 final-form regulations approved by IRRC to the General Assembly. The concurrent resolution was not passed by the General Assembly within 30 calendar days or 10 legislative days from the reporting of the concurrent resolution.

On June 23, 2016, Act 52 was enacted establishing the Pennsylvania Grade Crude Development Advisory Council and abrogating the rulemaking concerning standards at oil and gas well sites approved by the Board in 2016 prior to the effective date of Act 52 "insofar as such regulations pertain to conventional oil and gas wells."

The Department delivered the pre-Act 52 final-form regulations to the Office of Attorney General for form and legality review on June 27, 2016. In accordance with the Regulatory Review Act and the Commonwealth Attorneys Act, the Office of Attorney General directed the Department to make changes to the pre-Act 52 final-form regulations to comply with Act 52. Specifically, the Office of Attorney General directed the Department to comply with Act 52 by removing all amendments or additions to the final-form regulations in Chapter 78 regarding conventional oil and gas wells prior to resubmission to the Office of Attorney General for review. Additionally, the Office of Attorney General directed the Department to retain all deletions and modifications within the pre-Act 52 final-form regulations of Chapter 78 that relate to the unconventional oil and gas industry and to ensure that the requirements in the final-form rulemaking in Chapter 78a supersede any conflicting requirements in Chapter 78. The Office of Attorney General also objected to several typographical errors and sought corrections and clarifications to the following provisions: the definition of "mine influenced water" in § 78a.1, §§ 78a.13(a), 78a.17(b), 78a.65(b)(8), 78a.67(c)(2), 78a.75(a), 78a.75a(a), 78a.83(a)(2), 78a.83b(a)(1), 78a.87(b), 78a.88(c), (d), (d)(1) and (2), 78a.91(a) and 78a.101.

On July 26, 2016, the Department resubmitted this final-form rulemaking to the Office of Attorney General for review. In accordance with the Office of Attorney General's direction, the Department removed all amendments or additions to Chapter 78 regarding conventional oil and gas wells and retained the deletions and modifications in Chapter 78 that related solely to the unconventional wells. This revised final-form rulemaking also contains clarifications and corrections to respond to other issues identified by the Office of Attorney General, including the addition of § 78a.2 to clarify that Chapter 78a supersedes Chapter 78 for unconventional wells to avoid any potential conflict between the requirements in Chapter 78 and Chapter 78a regarding unconventional wells. Later on July 26, 2016, the Office of Attorney General approved this revised final-form rulemaking for form and legality under the Commonwealth Attorneys Act. The final-form rulemaking in Annex A is the revised final-form rulemaking as approved by the Office of Attorney General. This preamble was revised to reflect the final-form rulemaking as approved by the Office of Attorney General in conformance with Act 52.

The Joint Committee on Documents met on August 18, 2016, and voted to direct the Bureau to publish this final-form rulemaking.

E. *Summary of Regulatory Requirements*

As noted in Section D, in response to comments and Act 126, this final-form rulemaking contains new Chapter 78a for unconventional wells and amendments to Chapter 78 to delete conflicting requirements for unconventional wells to clarify that Chapter 78a supersedes Chapter 78

regarding unconventional wells. To clearly summarize these regulations, the Department will discuss each chapter in turn.

There are many sections in Chapter 78a that were not amended by this final-form rulemaking, but were carried over from existing Chapter 78 because they apply equally to conventional and unconventional well operations. Excellent examples of both of these nonsubstantive changes are the well plugging regulations in §§ 78a.91—78a.98 (relating to plugging). The only changes to these sections in Chapter 78a are to correct statutory citations necessitated by the passage of the 2012 Oil and Gas Act. These sections are repeated in their entirety in Chapter 78a, with proper cross-references to other sections in Chapter 78a.

Chapter 78. Oil and gas wells

§ 78.1. Definitions

The definitions of “nonvertical unconventional well” and “vertical unconventional well” are deleted from this section.

§ 78.19. Permit application fee schedule

This section is amended to delete unconventional well permit application fees.

§ 78.55. Control and disposal planning

This section is amended to delete subsection (f), which related exclusively to emergency response planning for unconventional wells.

§ 78.72. Use of safety devices—blow-out prevention equipment

Subsections (a)(1) and (j) are deleted as the blow-out prevention provisions only applied to unconventional wells. This section is renumbered accordingly.

§ 78.121. Production reporting

Subsection (a) is amended to delete reporting requirements for unconventional wells. The final sentence of the section regarding electronic reporting of production data is renumbered as subsection (b).

Chapter 78a. Unconventional wells

§ 78a.1. Definitions

This final-form rulemaking contains new or revised definitions for “ABACT—antidegradation best available combination of technologies,” “abandoned water well,” “accredited laboratory,” “Act 2,” “anti-icing,” “approximate original conditions,” “barrel,” “body of water,” “borrow pit,” “building,” “centralized impoundment,” “certified mail,” “common areas of a school’s property,” “condensate,” “de-icing,” “floodplain,” “freeboard,” “gathering pipeline,” “inactive well,” “limit of disturbance,” “modular aboveground storage structure,” “oil and gas operations,” “other critical communities,” “PCSM—post-construction stormwater management,” “PCSM plan,” “PNDI—Pennsylvania Natural Diversity Inventory,” “PNDI receipt,” “PPC plan—Preparedness, Prevention and Contingency plan,” “pit,” “playground,” “pre-wetting,” “primary containment,” “process or processing,” “public resource agency,” “regional groundwater table,” “regulated substance,” “residual waste,” “secondary containment,” “stormwater,” “threatened or endangered species,” “WMP—water management plan,” “watercourse,” “waters of the Commonwealth,” “well development impoundment,” “well development pipelines” “wellhead protection area” and “wetland.”

Under statutory changes in the 2012 Oil and Gas Act, this final-form rulemaking provides new definitions for

“act,” “owner,” “public water supply,” “water purveyor,” “water source” and “well operator or operator.”

The definition of “mine influenced water” was amended in this final-form rulemaking at the direction of the Office of Attorney General to address concerns that the definition in the pre-Act 52 final-form regulations did not establish a binding norm. The language in this final-form rulemaking matches the standards established in § 105.3(a)(3) (relating to scope).

§ 78a.2. Applicability

This section is added to clarify that Chapter 78a applies to unconventional wells and that Chapter 78a supersedes any regulations in Chapter 78 that might appear to apply to unconventional wells. This change was made at the direction of the Office of Attorney General.

§ 78a.15. Application requirements

The revisions to subsection (a) require well permit applications to be submitted electronically through the Department’s web site.

Subsection (b.1) establishes that if the proposed limit of disturbance is within 100 feet measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland greater than 1 acre in size, the applicant shall demonstrate that the well site location will protect that watercourse or bodies of water. This provision is needed to ensure protection of waters of the Commonwealth—especially in light of the Supreme Court’s decision in *Robinson Twp. v. Commonwealth*, 83 A.3d 901 (Pa. 2013) (*Robinson Twp.*) enjoining the application of the setbacks in section 3215(b) of the 2012 Oil and Gas Act (relating to well location restrictions). Operators can demonstrate that they will be protective of waters of the Commonwealth in several ways, including obtaining other permits or providing appropriate plans.

Subsection (c) is added to address statutory changes in the 2012 Oil and Gas Act that require the Department to review a well permit applicant’s parent and subsidiary corporations’ compliance history for operations in this Commonwealth.

Subsection (d) is added to address well permit applicants to consult with the Pennsylvania Natural Heritage Program regarding the presence of State or Federal threatened or endangered species where the proposed well site or access road will be located and outlines a process to address any adverse impacts. Many well permit applicants address impacts to threatened or endangered species when fulfilling their permitting obligations under Chapter 102. For that reason, subsection (e) is added to specify that compliance with §§ 102.5 and 102.6(a)(2) (relating to permit requirements; and permit applications and fees) is deemed to comply with the requirements to address threatened or endangered species as part of the well permit application process.

Subsection (f) outlines a process for the Department to consider the impacts to public resources when making a determination on a well permit in accordance with the Department’s constitutional and statutory obligations to protect public resources. Subsection (f) requires well permit applicants to identify when the proposed well site or access road may impact a listed public resource, notify applicable public resource agencies, and provide the Department and the public resource agencies with a description of the functions and uses of the public resources and avoidance or mitigation measures to be taken, if any. This section also provides applicable public resource agencies the opportunity to submit comments to the Department,

including any recommendations to avoid or minimize impacts, during a 30-day time frame. The Department notes that these provisions do not necessarily amount to setbacks, and are intended to protect the use and function of the particular public resource.

Subsection (g) provides the criteria the Department will consider when deciding whether to impose conditions on a well permit necessary to prevent a probable harmful impact to public resources.

Antidegradation requirements in Chapter 93 (relating to water quality standards) are reflected in subsection (h). This subsection requires a well permit applicant proposing to drill a well that involves 1 to 5 acres of earth disturbance over the life of the project that is located in a special protection watershed to submit an erosion and sediment control plan with the well permit application. These provisions seek to codify an existing component of the well permit application and are necessary to ensure that the Department meets its antidegradation requirements in Chapter 93.

§ 78a.17. Permit expiration and renewal

This section codifies the Department's interpretation of the permit requirements established by section 3211(i) of the 2012 Oil and Gas Act. Permits will expire unless drilling is started within 1 year of permit issuance. If drilling is started within 1 year, operators shall pursue drilling "with due diligence" or the permit will expire. Subsection (a) sets that expiration at 16 months from permit issuance unless an extension for good cause is obtained. Operators can also apply for a single 2-year renewal under subsection (b), and any new buildings or water wells installed after the initial permit was issued must be included on the renewal plat but do not block renewal of the permit.

§ 78a.18. Disposal and enhanced recovery well permits

Because disposal and enhanced recovery wells are by definition "conventional wells," this section refers operators to the requirements in § 78.18 (relating to disposal and enhanced recovery well permits). This section might come into play when an operator chooses to convert an unconventional well regulated by Chapter 78a into a disposal or enhanced recovery well regulated under Chapter 78.

§ 78a.51. Protection of water supplies

The amendments clarify that the presumption of liability established in section 3218(c) of the 2012 Oil and Gas Act does not apply to pollution resulting from well site construction activities. Subsection (c) also mirrors the statutory language stating that the presumption applies whenever impacts occur "as a result of completion, drilling, stimulation or alteration of the unconventional well."

The 2012 Oil and Gas Act established a new provision that specifies a restored or replaced water supplies must meet the standards in the Pennsylvania Safe Drinking Water Act (SDWA) (35 P.S. §§ 721.1—721.17) or be comparable to the quality of the water supply before it was affected if that water was of a higher quality than those standards. This section amended to reflect this statutory language.

§ 78a.52. Predrilling or prealteration survey

The amendments to subsection (d) establish a new process for submitting predrill sample results to the Department and applicable water users. Under this process, an operator electing to preserve its defenses under section 3218(d)(2)(i) of the 2012 Oil and Gas Act shall

submit all sample results taken as part of a survey to the Department within 10 business days of receipt of all the sample results taken as part of that survey. The current practice is to require submission with 10 days of receipt of each individual sample result, leading to piecemeal submissions. A copy of sample results shall be provided to water users within 10 business days of receipt of the sample results.

Subsection (g) reflects new 2012 Oil and Gas Act requirements that unconventional well operators provide written notice to water supply owners that the presumption established in section 3218(c) of the 2012 Oil and Gas Act may be void if the landowner or water purveyor refuses to allow the operator access to conduct a predrilling or prealteration survey and provided that the operator submits proof of the notice to the Department.

§ 78a.52a. Area of review

This section requires operators to identify abandoned, orphan, active and inactive wells within 1,000 feet of the vertical and horizontal wellbore prior to hydraulic fracturing. The identification process requires operators to review the Department's orphan and abandoned well database, review farm line maps and submit a questionnaire to landowners whose property lies within the prescribed area of review prior to drilling in cases where hydraulic fracturing activities are anticipated at the well site. Other available databases and historical sources should also be consulted. The section outlines how operators can conduct this identification, including consulting with the Department's database, farm line maps and submitting a questionnaire to surface landowners. The results of this survey shall be provided to the Department, and under subsection (f) the Department can require additional information or measures as are necessary to protect the waters of the Commonwealth.

§ 78a.53. Erosion and sediment control and stormwater management

The amendments to this section cross-reference the requirements of Chapter 102. This section also specifies that best management practices (BMP) for erosion and sediment control for oil and gas activities are contained in several guidance documents developed by the Department.

§ 78a.55. Control and disposal planning; emergency response for unconventional wells

This section requires all oil and gas well operators to develop and implement a site-specific PPC plan for oil and gas operations. This requirement clarifies existing requirements in § 91.34 (relating to activities utilizing pollutants) and § 102.5(l). Additionally, site-specific PPC plans are needed to address site-specific conditions, including local emergency contact information.

There may be instances when the operator finds that a PPC plan prepared for one well site is applicable to another site. Each individual plan shall be analyzed prior to making this determination. It is not the intent of this final-form rulemaking to require that each PPC plan be separately developed and different for each well site. The Department understands that many of the practices covered in the PPC plan are the same for a given operator. It is also not the intent of this final-form rulemaking to require that all PPC plans be revised annually. In many cases, if conditions at the site do not change, there will not be a need to make revisions to the PPC plan.

The amendments also provide that a PPC plan developed in conformance with the *Guidelines for the Develop-*

ment and Implementation of Environmental Emergency Response Plans, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 400-2200-001, as amended and updated, will be deemed to meet the requirements of this section.

§ 78a.56. *Temporary storage*

As an initial matter, this section's heading is changed from "pits and tanks for temporary containment" to "temporary storage" to clarify the difference between temporary storage requirements and long-term containment requirements in § 78a.57 and §§ 78a.64 and 78a.64a (relating to secondary containment around oil and condensate tanks; secondary containment). The equipment covered by this section shall be removed in accordance with the requirements of § 78a.65 within 9 months of completion of drilling, accounting for the "temporary" nature of this storage.

For unconventional operators, final-form § 78a.56 bans the use of pits for temporary waste storage at well sites. The Department has determined that it is appropriate to remove this practice because it is not commonly used by unconventional operators. Additionally, the typical type and scope of use by unconventional operators is generally incompatible with technical standards for temporary pits prescribed under § 78.56.

Subsection (a)(2) specifies that modular aboveground storage structures may be used to temporarily contain regulated substances upon prior Department approval and notice prior to installation. Modular aboveground storage structures of less than or equal to 20,000 gallons capacity may be used without prior Department approval. The Department will maintain a list of approved modular structures on its web site, although a siting review will still be required for each modular aboveground storage structure.

This final-form rulemaking also includes new monitoring requirements for tanks at unconventional well sites or, in the alternative, valve and access lid requirements for tanks. Additionally, this section establishes new signage requirements for tanks.

§ 78a.57. *Control, storage and disposal of production fluids*

The amendments to this section prohibit the use of open top structures and pits to store brine and other production fluids generated during the production operations of a well. Existing production pits shall be reported to the Department by April 8, 2017, and properly closed by October 10, 2017. Subsection (a) also codifies the Department's interpretation of the SWMA exemption in section 3273.1 of the 2012 Oil and Gas Act. Only wastes generated at a well site or entirely for beneficial reuse at well site may be stored at that well site without a SWMA permit.

If new, refurbished or replaced tanks are used to store these fluids, these tanks must be equipped with secondary containment. This section also establishes new performance and technical standards for tanks storing brines and other production fluids generated during production operations. Subsection (e) outlines requirements for use of underground or partially buried storage tanks that are used to store brine and other fluids produced during operation of the well.

Subsections (f) and (g) codify the requirement in section 3218.4(b) of the 2012 Oil and Gas Act (relating to corrosion control requirements) that "permanent aboveground and underground tanks must comply with

the applicable corrosion control requirements in the department's storage tank regulations" by cross-referencing the applicable storage tank regulations in Chapter 245 (relating to administration of the Storage Tank and Spill Prevention Program). Because the Oil and Gas Program does not certify storage tank inspectors, that provision of the storage tank regulation is not explicitly excepted from the cross-reference.

Subsection (h) establishes a monthly tank inspection requirement, similar to the monthly maintenance "walk-around" inspections currently required by the storage tank program (see §§ 245.513(b)(2) and 245.613(b) (relating to preventive maintenance and housekeeping requirements; and monitoring standards)).

§ 78a.58. *Onsite processing*

The amendments establish provisions regarding wastewater processing at well sites, codifying the Department's current approval process for onsite oil and gas waste processing. Subsection (a) allows operators to process fluids generated by oil and gas wells at the well site when the fluids were generated or at the well site when all of the fluid is intended to be beneficially used to develop, drill or stimulate a well upon Department approval. Subsection (b) lists specific activities that do not require Department approval, including mixing fluids with freshwater, aerating fluids or filtering solids from fluids. These activities shall be conducted within secondary containment. Subsection (d) requires an operator processing oil and gas fluids onsite to develop a radiation protection action plan which specifies procedures for monitoring and responding to radioactive material or technologically enhanced naturally occurring radioactive materials (TENORM) produced by the treatment process. This subsection also requires procedures for training, notification, recordkeeping and reporting to be implemented. Subsection (e) specifies that drill cuttings may only be processed at the well site where those drill cuttings were generated, if approved by the Department. Subsection (g) allows for using approved processing facilities at subsequent well sites.

§ 78a.59a. *Impoundment embankments*

This section contains design and construction standards for well development impoundments, including construction and stabilization requirements for embankments.

§ 78a.59b. *Well development impoundments*

This section creates registration, performance, and safety and security requirements for well development impoundments. An impervious liner must be used and the bottom of the well development impoundment is required to be 20 inches above the seasonal high groundwater table. Operators shall document the depth of the seasonal high groundwater table, and the manner that it was ascertained. Also, this final-form rulemaking establishes that existing and new well development impoundments shall be registered with the Department and need to be restored within 9 months of completion of hydraulic fracturing of the last well serviced by the impoundment. An extension for restoration may be approved under § 78a.65(c). Land owners may request to the Department in writing that the impoundment embankments not be restored provided that the synthetic liner is removed. Finally, this section contains a process for storing mine influenced water (MIW) in well development impoundments to ensure that it will not result in pollution to waters of the Commonwealth.

§ 78a.59c. *Centralized impoundments*

By April 8, 2017, operators of existing centralized impoundments authorized by a Dam Permit for a Centralized Impoundment Dam for Oil and Gas Operations permit (DEP # 8000-PM-OOGM0084) shall elect to submit a closure plan to the Department or seek a permit for the facility under Subpart D, Article IX (relating to residual waste management). Subpart D, Article IX contains the requirements for managing residual waste properly, and these requirements apply to residual waste that is generated by any type of industrial, mining or agricultural operation. Operators of existing centralized impoundments shall obtain a waste permit or close the impoundment by October 8, 2019. Any new proposed wastewater storage impoundments shall obtain a permit from the Department's Waste Management Program prior to construction and operation. Subsection (b) establishes requirements for the closure plan and is modeled on facility closure plan requirements in the residual waste regulations.

§ 78a.60. *Discharge requirements*

The amendments to this section specify that operators discharging tophole water by land application shall document compliance with the regulatory requirements, including those under the Dam Safety and Encroachments Act (32 P.S. §§ 693.1—693.27), make the records available to the Department upon request and submit the relevant information in the well site restoration report. In addition, the amendments add fill or dredged material to this section. Finally, subsection (b)(7) contains limitations on discharges in proximity to watercourses or in the floodplain.

§ 78a.61. *Disposal of drill cuttings*

This section addresses disposal of drill cuttings on well sites. A distinction is made between cuttings generated above the surface casing seat, which are generally subject to less stringent disposal requirements, and cuttings from below the surface casing seat, which shall be disposed of in accordance with § 78a.62 or § 78a.63 (relating to disposal of residual waste—pits; and disposal of residual waste—land application). The section contains limitations on disposal in proximity to watercourses or in the floodplain. For land application, subsection (b)(9) states that loading and application rate of drill cuttings may not exceed a maximum of drill cuttings to soil ratio of 1:1. For all practical purposes, this limitation means that drill cuttings cannot be disposed of on unconventional well sites.

Under subsection (d), an operator may use solidifiers, dusting, unlined pits, attenuation or other alternative practices with Department approval. The Department will maintain a list of approved solidifiers on its web site, and use of an approved solidifier does not require separate Department review or approval.

Subsection (f) requires notice to the Department prior to disposal of drill cuttings, and notice to the surface landowner of the location and nature of the disposal within 10 business days after completion of disposal.

§ 78a.62. *Disposal of residual waste—pits*

§ 78a.63. *Disposal of residual waste—land application*

These sections establish that residual waste, including contaminated drill cuttings, may not be disposed of at an unconventional well site in a pit or through land application unless the operator obtains an individual permit to do so from the Department.

§ 78a.64. *Secondary containment around oil and condensate tanks*

This section reflects Federal spill prevention, control and countermeasure requirements under the Oil Pollution Act of 1990 (33 U.S.C.A. §§ 2701—2762), and requires secondary containment when a tank or tanks with greater than 1,320 gallons capacity are used on a well site to store oil or condensate. Subsection (e) requires existing condensate tanks to meet the requirements of this section when the tank is replaced, refurbished or repaired, or by October 9, 2018, whichever is sooner.

§ 78a.64a. *Secondary containment*

This new section requires that unconventional well sites be designed and constructed using containment systems and practices that prevent spills to the ground surface and off the well site in accordance with 2012 Oil and Gas Act requirements. This section specifies when these systems and practices shall be employed. This section specifies secondary containment requirements. Additionally, this section contains provisions regarding subsurface containment systems.

§ 78a.65. *Site restoration*

This section clarifies the well site restoration requirements, including when restoration is required if there are multiple wells drilled on a single well site and what constitutes a restoration after drilling. The section addresses the interplay between the Chapter 102 requirements and the restoration requirements in section 3216 of the 2012 Oil and Gas Act, which requires well site restoration both post-drilling and post-plugging.

This section largely restates the restoration requirements in section 3216 of the 2012 Oil and Gas Act and incorporates the Department's interpretation of these requirements as outlined in the "Policy for Erosion and Sediment Control and Stormwater Management for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities," Document No. 800-2100-008, which was finalized on December 29, 2012. Subsection (1) allows operators broad discretion to ensure wells and well sites can be operated safely while also complying with the site restoration requirements in the 2012 Oil and Gas Act.

For post-drilling, the regulation requires restoration of the well site within 9 months after completion of drilling of all permitted wells on the site or within 9 months of the expiration of all existing well permits on the site, whichever is later. For post-plugging, it requires restoration within 9 months after plugging the final well on a well site. The restoration time frames are consistent with requirements in the 2012 Oil and Gas Act.

Operators may request an extension of the restoration time frame because the extension will result in less earth disturbance, increased water reuse or more efficient development of the resources, or if restoration cannot be achieved due to adverse weather conditions or a lack of essential fuel, equipment or labor.

In addition to post-plugging and post-drilling, a well site shall be restored within 9 months after expiration of the drilling permit if the site is constructed and the well is not drilled.

"Areas not restored" do not fall within the provisions in § 102.8(n) (relating to PCSM requirements) and therefore must meet the requirements, among others, of § 102.8(g). Areas not restored include areas where there are permanent structures or impervious surfaces, therefore runoff

produced from these areas must be tributary to permanent post-construction stormwater management (PCSM) BMPs to ensure the runoff will be managed in accordance with the requirements of § 102.8.

Operators do not need to develop written restoration plans for all well sites and this final-form rulemaking requires development of written restoration plans only for well sites which require permit coverage under § 102.5(c).

Drilling supplies and equipment not needed for production may only be stored on the well site if written consent of the landowner is obtained, which is consistent with the requirements in section 3216 of the 2012 Oil and Gas Act.

After restoration, a site restoration report shall be provided to the Department and the surface landowner. Waste disposal information must be included in the site restoration report.

Subsection (g) allows for the satisfaction of the restoration requirements if written consent of the landowner is given provided that the operator develops and implements a site restoration plan that complies with subsections (a) and (b)(2)—(7) and all PCSM requirements in Chapter 102.

§ 78a.66. *Reporting and remediating spills and releases*

This section clarifies the requirements regarding reporting and remediating spills and releases of regulated substances on or adjacent to well sites and access roads. Subsection (b) establishes two instances when a spill or release shall be reported to the Department: (1) a spill or release of a regulated substance causing or threatening pollution of the waters of the Commonwealth, in the manner required under § 91.33 (relating to incidents causing or threatening pollution); and (2) a spill or release of 5 gallons or more of a regulated substance over a 24-hour period that is not completely contained by secondary containment. These reports shall be made by telephone as soon as practicable but no later than 2 hours after the spill or release was discovered. This section addresses what information must be included in the release report and interim remedial actions that should be taken in the short term following discovery of the spill or release.

This section also clarifies that the operator or responsible party shall remediate an area affected by a spill or release and outlines two different remediation options. Spills of less than 42 gallons to the surface that do not pollute or threaten to pollute waters of the Commonwealth may be remediated by removing the soil visibly impacted by the spill or release and properly managing the impacted soil in accordance with the Department's waste management regulations. Spills or releases of more than 42 gallons to the surface or that pollute or threaten to pollute waters of the Commonwealth shall be remediated to demonstrate attainment of an Act 2 cleanup standard in accordance with the process in subsection (c).

§ 78a.67. *Borrow pits*

This section provides requirements for noncoal borrow areas for oil and gas well development, including performance, registration and restoration requirements. The section implements the requirements established by section 3273.1(b) of the 2012 Oil and Gas Act, which exempts any borrow area where minerals are extracted solely for the purpose of oil and gas well development, including access road construction from the Noncoal Surface Mining Conservation and Reclamation Act (NSMCRA) (52 P.S. §§ 3301—3326), or a regulation promulgated under the NSMCRA, so long as the owner or operator of the well

meets certain conditions. Those conditions are outlined in this section, and include the borrow pit servicing an oil and gas well site where a well is permitted under section 3211 of the 2012 Oil and Gas Act or registered under section 3213 of the 2012 Oil and Gas Act (relating to well registration and identification) and meeting any applicable bonding requirements for wells serviced by the borrow pit. Also, well owners and operators shall operate, maintain and reclaim the borrow pit in accordance with the performance standards in Chapter 77, Subchapter I (relating to environmental protection performance standards).

Subsection (b) requires owners and operators to register the location of existing borrow pits with the Department by December 7, 2016. Subsection (d) requires an inspection of any existing borrow pits by April 6, 2017, and proper restoration or upgrade by October 10, 2017, for any substandard borrow pits.

The section also requires borrow pit restoration or permitting under the NSMCRA within 9 months after completion of drilling the final well on a well site serviced by the borrow pit or 9 months after the expiration of all well permits on well sites serviced by the borrow pit, whichever occurs later.

§ 78a.68. *Oil and gas gathering pipelines*

This section contains requirements regarding the construction and installation of gathering pipelines, including a limit on the extent of associated earth disturbance, flagging requirements and topsoil/subsoil standards. This final-form rulemaking requires that equipment refueling and staging areas must be out of floodways and least 50 feet away from a body of water, although materials staging within the floodway or within 50 feet of a water body may occur if first approved in writing by the Department. This final-form rulemaking requires that all buried metallic gathering pipelines shall be installed and placed in operation in accordance with 49 CFR Part 192, Subpart I or Part 195, Subpart H (relating to requirements for corrosion control; and corrosion control), codifying the requirements of section 3218.4(a) of the 2012 Oil and Gas Act.

§ 78a.68a. *Horizontal directional drilling for oil and gas pipelines*

This section contains requirements for horizontal directional drilling (HDD) associated with gathering and transmission pipelines, including planning, notification, construction and monitoring requirements. This section contains cross-references to other applicable regulatory requirements in Chapter 102 and Chapter 105 (relating to dam safety and waterway management). This section establishes that Department approval is required prior to using drilling fluid other than bentonite and water. The Department maintains a list of approved additives on its web site and any person using one of the approved additives does not require additional approval from the Department.

Additionally, this section specifies that HDD activities may not result in a discharge of drilling fluids to waters of the Commonwealth. This final-form rulemaking requires that bodies of water and watercourses over and adjacent to HDD activities be monitored for any signs of drilling fluid discharges.

In the event of a discharge, this section outlines the steps that an operator shall take to report and address that discharge. This section also proposes that any water supply complaints received by the operator be reported to the Department within 24 hours. This final-form rule-

making requires that bodies of water and watercourses over and adjacent to HDD activities be monitored for any signs of drilling fluid discharges.

This final-form rulemaking includes a requirement for a PPC plan for HDD with a site-specific contingency plan that describes the measures to be taken to control, contain and collect any discharge of drilling fluids and minimize impacts to waters of the Commonwealth. The Department believes that due to the heightened potential for pollution to waters of the Commonwealth that HDD creates, a separate PPC plan is required for this specific activity. A separate PPC plan is not required for HDD activities provided that the PPC plan developed under § 78a.55 meets the requirements in § 78a.68a (relating to horizontal directional drilling for oil and gas pipelines).

§ 78a.68b. Well development pipelines for oil and gas operations

This section contains the requirements for well development pipelines associated with oil and gas operations, including installation, construction, flagging, pressure testing, inspection operation, recordkeeping and removal requirements. This section also contains cross-references to applicable regulatory requirements in Chapters 102 and 105.

This final-form rulemaking requires that well development pipelines that transport flowback water and other wastewaters be installed aboveground. Subsection (c) specifies that well development pipelines may not be installed through existing stream culverts, storm drain pipes or under bridges that cross streams without approval by the Department under § 105.151 (relating to permit applications for construction or modification of culverts and bridges).

This final-form rulemaking requires certain safety measures with well development pipelines used to transport fluids other than fresh ground water, surface water and water from water purveyors or approved sources. They shall be pressure tested prior to being first placed into service and after the pipeline is moved, repaired or altered. Well development pipelines must have shut off valves, check valves or other methods of segmenting the pipeline placed at designated intervals that prevent the discharge of more than 1,000 barrels of fluid. They may not have joints or couplings on the segments that cross waterways unless secondary containment is provided. Highly visible flagging, markers or signs need to be placed at regular intervals along the well development pipeline. They cannot be used to transport flammable materials.

Well development pipelines shall be removed when the well site is restored. This final-form rulemaking requires operators to obtain Department approval for well development pipelines in service for more than 1 year.

This final-form rulemaking requires that the operator maintain certain records regarding well development pipelines, including the location, type of fluids transported, the approximate time of installation, pressure test results, defects and repairs. The records need to be retained for 1 year after their removal and be made available to the Department upon request.

§ 78a.69. Water management plans

WMPs are a requirement for unconventional wells in section 3211(m) of the 2012 Oil and Gas Act. This section codifies existing requirements to protect quality and quantity of water resources in the Commonwealth, including freshwater resources, from adverse impacts to the

watershed considered as a whole from potentially inappropriate withdrawals of water. Further, this final-form rulemaking protects water quality and quantity by ensuring water is available to other users of the same water source and protects and maintains the designated and existing uses of the water source. This final-form rulemaking mirrors most of the requirements of the Susquehanna River Basin Commission and the Delaware River Basin Commission to ensure that requirements are consistent Statewide, regardless of which river basin an operator withdraws water from. This section also outlines the circumstances under which the Department may deny a WMP application or suspend, revoke or terminate an approved WMP.

§ 78a.70. Road-spreading of brine for dust control and road stabilization

§ 78a.70a. Pre-wetting, anti-icing and de-icing

These sections establish that brines and production fluids from unconventional wells may not be used for dust suppression and road stabilization, or for pre-wetting, anti-icing and de-icing.

§ 78a.73. General provision for well construction and operation

Subsection (c) establishes requirements for monitoring wells during hydraulic fracturing. First, operators of active, inactive, abandoned and plugged and abandoned wells that are vertically proximate to the stimulation perforations shall be notified at least 30 days prior to the start of drilling. Orphan and abandoned wells that are vertically proximate to the stimulation perforations shall be monitored by the operator stimulating the well. Wells that penetrate within defined vertical separation distances, or that have an "unknown true vertical depth" have the potential to serve as preferential pathways allowing pollution of the waters of the Commonwealth.

Operators shall notify the Department of any changes to wells being monitored and shall take action to prevent pollution or discharges to the surface. Operators also shall notify the Department if they observe any treatment pressure or volume changes indicative of abnormal fracture propagation at the well being stimulated or if the operator is otherwise made aware of a confirmed well communication incident associated with their stimulation activities.

Finally, this final-form rulemaking codifies the Department's current position that an operator that alters an abandoned and orphaned well by hydraulic fracturing shall plug that well.

§ 78a.121. Production reporting

This section requires unconventional operators to report production on a monthly basis in accordance with section 3 of the Unconventional Well Report Act. Additionally, this section requires unconventional operators to report their waste production on a monthly basis within 45 days of the end of the month, including the specific facility or well site where the waste was managed.

§ 78a.122. Well record and completion report

This section addresses new well report and stimulation record requirements, including 2012 Oil and Gas Act requirements. For the well record, new requirements include whether methane was encountered other than in a target formation, the country of origin and manufacture of tubular steel products used in the construction of the well (section 3222(b.1)(2)(ii) of the 2012 Oil and Gas Act) and the borrow pit used for well site development, if any.

For the well completion report, the additional information includes: the trade name, vendor and a brief descriptor of the intended use or function of each chemical additive in the stimulation fluid; a list of the chemicals intentionally added to the stimulation fluid, by name and chemical abstract service number; and the maximum concentration, in percent by mass, of each chemical intentionally added to the stimulation fluid (section 3222(b.1)(1)(i)—(iii) of the 2012 Oil and Gas Act), the well development impoundment, if any, used to complete the well and a certification that the monitoring plan required under § 78a.52a (relating to area of review) was conducted as outlined in the area of review report.

§ 78a.123. *Logs and additional data*

This final-form rulemaking addresses 2012 Oil and Gas Act requirements and clarifies when industry logs and data collected during drilling activities need to be submitted to the Department, either by being required (standard logs) or requested (nonstandard logs and additional data requested prior to drilling).

§ 78a.309

Section 78.309 (relating to phased deposit of collateral) was not carried over to Chapter 78a in response to new bonding requirements in the 2012 Oil and Gas Act.

F. *Changes from Proposed to Final-Form Rulemaking: Summary of Major Comments and Responses*

The public comment period on the proposed rulemaking was open for 90 days, beginning with publication of the proposed rulemaking at 43 Pa.B. 7377 and ending on March 14, 2014, as extended at 44 Pa.B. 648 (February 1, 2014). The Board also held nine public hearings on the proposed rulemaking:

- January 9, 2014, in West Chester, PA
- January 13, 2014, in Williamsport, PA
- January 15, 2014, in Meadville, PA
- January 16, 2014, in Mechanicsburg, PA
- January 22, 2014, in Washington, PA
- January 23, 2014, in Indiana, PA
- January 27, 2014, in Tunkhannock, PA
- February 10, 2014, in Troy, PA
- February 12, 2014, in Warren, PA

The Department received 23,213 public comments on the proposed rulemaking, including a significant number of form letter comments/petitions. In addition, around 300 individuals testified at the 9 public hearings. IRRC also submitted comments on the proposed rulemaking.

Based on the review of those comments, the Department developed draft final-form rulemaking and used the ANFR procedure published at 45 Pa.B. 1615 (April 4, 2015). The public comment period on the ANFR was open for 45 days, until May 19, 2015, and the Department held three public hearings on the draft final-form regulations:

- April 29, 2015, in Washington, PA
- April 30, 2015, in Warren, PA
- May 4, 2015, in Williamsport, PA

The Department received 4,947 comments on the draft final-form regulations. Of those, 302 were unique comments and the balance was form letter comments. In addition, 129 individuals provided testimony on the ANFR at the 3 public hearings.

The major comments received on the proposed rulemaking and the draft final-form regulations, and the Department's responses, are summarized as follows. It is worth noting at the outset that on nearly every issue raised by the proposed rulemaking and the draft final-form regulations, the range of comments spanned from the provision being unreasonable, too restrictive and unnecessary, to the provision being not protective or restrictive enough but critical for the protection of public health and the environment.

Banning hydraulic fracturing

The Department received many comments on the proposed rulemaking and the ANFR suggesting that the Commonwealth should ban the practice of hydraulic fracturing or put a moratorium in place until various objectives could be achieved. The Department does not have the statutory authority to ban hydraulic fracturing within this Commonwealth. Banning hydraulic fracturing would require an act of the General Assembly.

Well drilling can be done in a safe and environmentally sound way, provided applicable laws are adhered to by the regulated community. The amendments in Chapter 78a are intended to further strengthen these standards to ensure this Commonwealth's environment and the health of its citizens is properly protected. The Department believes the revisions to Chapter 78a are comprehensive, enforceable, consistent with applicable statutes, and provide appropriate protections for public health and safety and the environment. The Department will continue to study the efficacy of its regulatory programs and make improvements to the regulations as necessary.

Issues outside of the scope of this final-form rulemaking

The Department received many comments that were outside the scope of this final-form rulemaking. For example, several commentators suggested that the Department should significantly increase the bonds required of operators under authority granted by section 3225 of the 2012 Oil and Gas Act (relating to bonding). While the Board does have authority to alter bond amounts through regulation, that topic was not considered in this final-form rulemaking and so no changes were made to those sections in this final-form rulemaking. Similarly, many commentators raised air quality issues related to oil and gas operations. Air emissions from oil and gas operations are regulated under Subpart C, Article III (relating to air resources), not Chapters 78 and 78a. Revisions to Subpart C, Article III are beyond the scope of this final-form rulemaking. However, air emissions from the oil and gas sector are regulated through a series of measures including the best available technology which includes equipment, devices, methods and techniques that will prevent, reduce or control emissions of air contaminants, including hazardous air pollutants, to the maximum degree possible.

Noise mitigation requirements

The Department considered including noise mitigation requirements in this final-form rulemaking. Based on public comment to the proposed rulemaking raising concerns over noise issues at unconventional well sites, the Department developed § 78a.41, regarding noise mitigation, to address noise issues at unconventional well sites and published that provision as part of the ANFR.

Since that time, the Department has determined that the consideration of noise and possible mitigation is a concern not only with regard to unconventional gas production, but is an issue raised by other activities regulated by the Department (for example, mining). Be-

cause of this, additional cross-program collaboration and coordination will be required. In addition, there are a number of extremely complex technical issues that have to be resolved to develop a reasonable but effective noise mitigation program. This complexity is demonstrated in the scope and breadth of the comments submitted on the ANFR, both supporting and opposing the draft regulatory provisions. Finally, the science surrounding noise issues is continuing to develop, particularly with regard to impacts to human health and sensitive wildlife populations. Any reasonable and effective regulation regarding noise issues will need to take those developments into account.

For these reasons, the Department removed draft § 78a.41 from this final-form rulemaking to consider standards and enforcement that will maximize consistency and efficiency, where possible, among Department programs, while addressing the complex technical issues presented by noise at well sites. In its place, the Office of Oil and Gas Management intends to develop a noise mitigation “best practices manual” with input from a wide range of experts on noise issues as well as the public. If rulemaking is appropriate to address noise issues at well sites, the Department will develop regulations at a later date. Exclusion of noise mitigation requirements is the least burdensome, acceptable alternative at this time.

Centralized tank storage

Based on public comment to the proposed rulemaking raising concerns over the lack of permitting options for centralized off-site tank storage, the Department developed draft § 78.57 (relating to wells in a hydrogen sulfide area) and § 78a.57, regarding centralized tank storage, to provide for the option of centralized tank storage off of the well site under the oil and gas regulations. These sections were developed with significant input and review from the Department’s waste management and storage tank programs to ensure that the draft final-form regulations were protective of public health and safety and the environment. The Department also felt that these sections were appropriate for inclusion in the draft final-form regulations to give operators an environmentally-protective option for offsite wastewater management given the Department’s decision to eliminate the use of centralized impoundments without residual waste permits in § 78a.59c of the draft final-form regulations. These sections were published as part of the ANFR.

There was widespread opposition to these new sections across the spectrum of commentators, for various reasons. In keeping with the Department’s interpretation of section 3273.1(a) of the 2012 Oil and Gas Act (relating to relationship to solid waste and surface mining), and the decision to eliminate the use of centralized impoundments without residual waste permits in § 78a.59c of the draft final-form rulemaking, the Department removed draft § 78a.57 from this final-form rulemaking. Operators wishing to manage oil and gas wastewater off of a well site, or on a well site but not consisting entirely of waste generated at that well site or waste that will be beneficially reused at that well site shall obtain a permit to do so under the Department’s residual waste regulations rather than operating under Chapter 78 or Chapter 78a.

Transparency and public information

In regard to public access to oil and gas well information, the Department currently has more than a dozen interactive reports on its web site that provide information such as: permits issued; operator well inventories; inspection, violation and enforcement information; spud information; and target, oldest and producing formations

associated with each well. Users are able to run these reports based upon specific parameters such as region, county, municipality, operator, date range, and the like. Additionally, the Department has an Oil & Gas Mapping application on its web site that allows users to geographically locate oil and gas wells using various map layers and aerial photography. The mapping application allows users to search for wells based upon numerous parameters. The mapping application also provides the additional functionality of displaying electronic copies of actual documents such as well permits/applications, inspection reports and operator’s responses to violations. The Department will continue to expand both the amount of oil and gas well information available on its web site, and the ability to readily locate, retrieve and export that information.

Regulatory Review Act compliance

Commentators raised issues with the process used to develop and support the rulemaking under the Regulatory Review Act. The Department complied with the requirements of the Regulatory Review Act and other applicable Pennsylvania statutes. The revisions to Chapter 78a are consistent with the Pennsylvania Constitution and applicable statutes, and provide reasonable protections for public health and safety and the environment. The Department conducted the requisite analyses in developing the proposed and final-form rulemakings. These analyses are reflected in the Regulatory Analysis Form, preamble and other rulemaking documents. Among other things, the Department considered the potential costs, benefits, need, impacts on small businesses, alternatives and other potential impacts of the rulemaking. This final-form rulemaking represents the Department’s revisions to the rulemaking after careful consideration of all comments received during the rulemaking process and of the additional public input.

A subset of these concerns related to forms and guidance documents necessary to implement this final-form rulemaking and lack of availability of those documents for review concurrently with review of the proposed rulemaking and the ANFR. The Department will make forms and guidance documents available prior to adoption of this final-form rulemaking to address this concern. The Department notes that forms and guidance can only be based on the performance standards and requirements established by this final-form rulemaking and do not impose binding obligations independent of that authority. Therefore, development of those documents without a firm understanding of exactly what the requirements of this final-form rulemaking is impractical.

§ 78a.1. Definitions

Several definitions were added to this section, including “ABACT—antidegradation best available combination of technologies,” “abandoned water well,” “accredited laboratory,” “barrel,” “building,” “certified mail,” “common areas of a school’s property,” “floodplain,” “inactive well,” “limit of disturbance,” “modular aboveground storage structure,” “other critical communities,” “PCSM—post-construction stormwater management,” “PNDI—Pennsylvania Natural Diversity Inventory,” “PNDI receipt,” “playground,” “primary containment,” “public resource agency,” “residual waste,” “secondary containment,” “threatened or endangered species,” “waters of the Commonwealth” and “well-head protection area.” These definitions were added to provide clarity to the substantive sections of this final-form rulemaking or to address provisions added to this final-form rulemaking. An example of the latter would be “common areas of a school’s property” and “playground,”

as those terms were added to the list of public resources to be considered under § 78a.15(f) (relating to application requirements).

Two definitions were changed to better reflect the substantive sections of this final-form rulemaking and in response to comments: “centralized impoundment” (to better reflect the changes to § 78a.59c); and “oil and gas operations” (to eliminate well location assessment and seismic activities from the definition in response to comments). The definition of “pit” was changed to reflect the ban on the use of pits at unconventional well sites.

Initially, “well location assessment” and “seismic operations” were included in the definition of “oil and gas operations.” The Department received many comments requesting clarification of the term suggesting that these items were not appropriate for inclusion in the definition. In many cases, the operator is not even the entity conducting these activities. The Department amended the definition of “oil and gas operations” by deleting those two terms.

The definition of “mine influenced water” was amended in this final-form rulemaking to address concerns that the definition approved by the Board on February 3, 2016, and IRRC on April 21, 2016, did not establish a binding norm. The new language matches the standards established in § 105.3(a)(3). This change was made at the direction of the Office of Attorney General during its review of the final-form regulations for form and legality.

Finally, several definitions were deleted as they became unnecessary due to changes in the substantive provisions or the bifurcation of the regulations into two separate chapters. Deleted definitions include “certified laboratory,” “conventional formation” (§ 78a.1), “conventional well” (§ 78a.1), “containment system,” “nonvertical unconventional well” (§ 78.1), “vertical unconventional well” (§ 78.1) and “WMP—water management plan” (§ 78.1).

§ 78a.2. Applicability

This final-form rulemaking adds this section to clarify that Chapter 78a applies to unconventional wells and that Chapter 78a supersedes any regulations in Chapter 78 that might appear to apply to unconventional wells. This section was added at the direction of the Office of Attorney General during its review of the pre-Act 52 final-form regulations for form and legality.

§ 78a.15. Application requirements

Protecting waters of the Commonwealth

Section 78a.15(b.1) is added to this final-form rulemaking. This subsection establishes that if the proposed limit of disturbance is within 100 feet measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland greater than 1 acre in size, the applicant shall demonstrate that the well site location will protect those water course or bodies of water. These provisions are needed to ensure protection of waters of the Commonwealth—especially in light of the Supreme Court’s decision in *Robinson Twp.*, which enjoined the application of the water quality protection setbacks in section 3215(b) of the 2012 Oil and Gas Act. Under The Clean Streams Law (35 P.S. §§ 691.1—691.1001), the Department has an obligation to develop regulations when it finds that an activity may create a danger to waters of the Commonwealth. These provisions are necessary to avoid pollution. Additionally, this demonstration is currently part of the well permit application for both conventional and unconventional wells. Accordingly, these provisions seek to codify an existing practice.

The Department received significant public comment on this provision. Some commentators argued that the buffer distance was too short while others argued that the Department does not have the authority to establish a buffer of any distance. Regarding the question of authority, the Department disagrees. The Department has broad authority under The Clean Streams Law to establish regulations to protect waters of the Commonwealth. Regarding the buffer distance, the Department believes that 100 feet is appropriate. Moreover, these provisions are similar to other requirements in 25 Pa. Code (relating to environmental protection) and are consistent with the riparian buffer requirements in Chapter 102.

As documented in the final-form rulemaking “Erosion and Sediment Control and Stormwater Management” amending Chapter 102 published at 40 Pa.B. 4861 (August 21, 2010), there is substantial scientific support for a 100-foot buffer from streams. One study is *Streamside Forest Buffer Width Needed To Protect Stream Water Quality, Habitat and Organisms: A Literature Review*, Bernard W. Sweeney and J. Denis Newbold, *Journal of the American Water Resources Association*, June 2014, which cites over 251 scientific articles and papers as sources for the paper which states that “overall, buffers ≥ 30 m wide [approximately 100 feet] are needed to protect the physical, chemical, and biological integrity of small streams.” For these reasons, the Department determined that 100 feet was a reasonable and appropriate area for additional review to ensure protection of waters of the Commonwealth.

Subsection (d) was amended in this final-form rulemaking to more accurately codify the Department’s current policy regarding impacts to threatened or endangered species, “Policy for Pennsylvania Natural Diversity Inventory (PNDI) Coordination During Permit Review and Evaluation,” Doc. No. 021-0200-001. Subsection (e) is amended to codify the Department’s policy that PNDI clearances obtained less than 2 years prior for existing well sites as part of erosion and sediment control permitting can serve as the PNDI clearance for a subsequent well permit application.

Subsection (f) outlines a process for the Department to consider the impacts to public resources when making a determination on a well permit in accordance with the Department’s constitutional and statutory obligations to protect public resources. This public resource impact screening subsection, along with water supply replacement, waste management and area of review provisions, formed one of four “pillars” of this final-form rulemaking. Not surprisingly, this subsection generated significant comments across the entire spectrum of issues. The significant comments, and changes to this final-form rulemaking as a result of those comments, are outlined as follows.

Authority

The public resource impact screening process in § 78a.15(f) and (g) is needed because the Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, The Administrative Code of 1929 (71 P.S. §§ 51—732), the 2012 Oil and Gas Act, The Clean Streams Law, the Dam Safety and Encroachments Act, the SWMA (35 P.S. §§ 6018.101—6018.1003) and other statutes. Moreover, the Department shares responsibility for the protection of natural resources with other Commonwealth agencies and municipalities that also have trustee duties under Article I, Section 27 of the Pennsylvania Constitution, as well as Federal agencies. To meet these constitutional and statu-

tory obligations, § 78a.15 establishes a process for the Department to identify, consider and protect public resources from the potential impacts of a proposed well and to coordinate with applicable public resource agencies.

Public resource consideration has been a required component of the well permit application process since the Oil and Gas Act was first enacted in 1984 (58 P.S. §§ 601.101—601.605) (repealed) (1984 Oil and Gas Act). The 1984 Oil and Gas Act was repealed by the act of February 14, 2012 (P.L. 87, No. 13) (Act 13). The provisions in this final-form rulemaking are needed to provide a clear process for identifying potentially impacted public resources, notifying applicable public resource agencies, soliciting any recommended mitigation measures and supplying the Department with sufficient information to determine whether permit conditions are necessary to avoid a potentially harmful impact to public resources.

If the limit of disturbance associated with a proposed oil or gas well site is located within a certain distance of a listed public resource as provided in § 78a.15(f)(1), the well permit operator shall provide additional information in the well permit application and notify applicable public resource agencies 30 days prior to submitting the well permit application. Under § 78a.15(f)(2), the public resource agencies have 30 days to provide written comments to the Department and the applicant on the functions and uses of the public resource and any recommended mitigation measures. The applicant is then afforded an opportunity to provide a response to those comments. The Department then evaluates the potential impacts and assesses the need for conditions in the well permit using the criteria in § 78a.15(g). Section 78a.15(g) is added to provide needed clarity regarding implementation of these obligations and to comply with section 3215(e) of the 2012 Oil and Gas Act, which specifically directs the Board to develop these criteria by regulation.

The right of the people of this Commonwealth to clean air, pure water, and the preservation of the natural, scenic, historic and esthetic values of the environment as expressly provided by Article I, Section 27 of the Pennsylvania Constitution is fundamental to the quality of life of the people of this Commonwealth. Additionally, public natural resources held in trust by the Commonwealth for the benefit of the people are a major economic contributor to Pennsylvania through tourism, outdoor fish and game sports, and recreation. The public resource impact screening provisions in this final-form rulemaking provide needed clarity and clear standards for the Department to carry out its trustee obligations in administering the 2012 Oil and Gas Act program and will ensure the continued availability and benefits of these public resources throughout this Commonwealth.

Despite the Department's duties and obligations as previously described, industry commentators argued that the Department does not have the statutory authority to promulgate regulations regarding public resources under § 78a.15(f) and (g) because the Pennsylvania Supreme Court enjoined section 3215(c) and (e) of the 2012 Oil and Gas Act in *Robinson Twp.* The Department asserts that section 3215(c) and (e) of the 2012 Oil and Gas Act was not enjoined or otherwise invalidated by *Robinson Twp.* and that neither the plurality nor the concurring opinions in *Robinson Twp.* read in their totality overturn the public resource protection requirements as part of the well permitting process. During the development of the proposed and final-form rulemakings this issue was being litigated in Commonwealth Court. See *Pennsylvania Independent Oil & Gas Association v. Commonwealth* (321

M.D. 2015). On September 1, 2016, the Commonwealth Court entered judgment in favor of the Department. The Court found that the Department's authority to consider the impacts of a proposed oil and gas well on public resources under section 3215(c) of the 2012 Oil and Gas Act was not invalidated by the Pennsylvania Supreme Court's decision in *Robinson Twp.* The Court agreed with the Department's argument that the Supreme Court enjoined the application of section 3215(c) of the 2012 Oil and Gas Act only to the extent it implements provisions in section 3215(b) of the 2012 Oil and Gas Act. The Court decided that the Department had the authority to consider public resources as part of the well permit review process solely under the authority of section 3215(c) of the 2012 Oil and Gas Act.

On September 29, 2016, the Commonwealth Court's opinion was appealed to the Pennsylvania Supreme Court. As of the date of this final-form rulemaking this matter is still pending before the Pennsylvania Supreme Court.

The Department's interpretation of *Robinson Twp.* and the outline of the authority for these provisions is as follows. The Pennsylvania Supreme Court's decision in *Robinson Twp.* invalidated section 3215(b)(4) and (d) of the 2012 Oil and Gas Act and sections 3303 and 3304 of the 2012 Oil and Gas Act (relating to oil and gas operations regulated by environmental acts; and uniformity of local ordinances) as unconstitutional. As for section 3215(c) and (e) of the 2012 Oil and Gas Act, the Pennsylvania Supreme Court held: "Sections 3215(c) and (e) . . . are not severable to the extent that these provisions implement or enforce those Sections of [the 2012 Oil and Gas Act] which we have found invalid and, in this respect, their application or enforcement is also enjoined." 83 A.3d 901 at 1000 (emphasis added).

Sections 3215(b) and (d), 3303 and 3304 of the 2012 Oil and Gas Act address: protection of surface water quality; comment and appeal rights of municipalities and storage operators; pre-emption of local ordinances; and uniformity of local ordinances, respectively. Section 3215(c) of the 2012 Oil and Gas Act is a separate, independent, free-standing provision that does not implement or enforce these invalidated provisions. Rather, section 3215(c) of the 2012 Oil and Gas Act requires the Department to consider the impacts of a proposed well on "public resources" including, but not limited to: publicly owned parks, forests, game lands and wildlife areas; National and State scenic rivers; National natural landmarks; habitats of threatened and endangered species and other critical communities; historical and archeological sites; and sources used for public drinking supplies.

Section 3215(e) of the 2012 Oil and Gas Act operates in tandem with section 3215(c) of the 2012 Oil and Gas Act. Under section 3215(e) of the 2012 Oil and Gas Act, the Board is directed to develop regulations to establish criteria for the Department to consider when conditioning well permits based on impacts to public resources identified under section 3215(c) of the 2012 Oil and Gas Act.

The Department believes that section 3215(c) and (e) of the 2012 Oil and Gas Act does not implement or enforce section 3215(b), 3215(d), 3303 or 3304 of the 2012 Oil and Gas Act and, therefore, remain valid and enforceable.

For these reasons, in addition to the authority previously discussed, the Department has argued that it retains a specific statutory obligation to protect public resources under section 3215(c) and (e) of the 2012 Oil and Gas Act.

However, even if those subsections were invalidated as some commentators assert the provision under the 1984 Oil and Gas Act mandating protection of public resources would then remain in effect. See section 205(c) of the 1984 Oil and Gas Act (58 P.S. § 601.205(c)) (repealed). Thus, the Board has authority under either the 2012 Oil and Gas Act or the prior 1984 Oil and Gas Act to promulgate regulations for the consideration of impacts to protect public resources when issuing an oil or gas well permit.

Additionally, other provisions of the 2012 Oil and Gas Act also support the requirements in § 78a.15 of this final-form rulemaking. The General Assembly recognized the constitutional obligation to protect public resources in section 3202 of the 2012 Oil and Gas Act (relating to declaration of purpose of chapter), which provides that the purpose of the 2012 Oil and Gas Act is to “[p]rotect the natural resources, environmental rights and values secured by the Constitution of Pennsylvania.” Under section 3274 of the 2012 Oil and Gas Act (relating to regulations), the Board has the authority to promulgate regulations necessary to implement the 2012 Oil and Gas Act. The public resource protection provisions in § 78a.15 provide a reasonable and appropriate process for the Department to implement the constitutional and statutory requirements previously discussed.

Further, the General Assembly has enacted several other statutes that provide the Department with the broad power and duty to protect public natural resources consistent with the mandates of Article I, Section 27 of the Pennsylvania Constitution, including The Clean Streams Law, the SWMA, the Dam Safety and Encroachment Act, Act 2 (35 P.S. §§ 6026.101—6026.908) and The Administrative Code of 1929. These statutes also provide authority for this rulemaking.

Additionally, the General Assembly has enacted statutes that provide authority for other Commonwealth agencies to protect public natural resources, and the Department coordinates with those agencies to fulfill its constitutional and statutory duties to protect public natural resources. The public resource protection provisions included in Chapter 78a facilitate the Department’s compliance with this obligation.

Finally, the public screening requirements provided in this final-form rulemaking establish a standardized and transparent process for the Department to identify, consider and protect public resources from the impacts of a proposed well and to coordinate with other public resource agencies with constitutional and statutory duties to conserve and maintain these resources, in a manner that demonstrates compliance with Article I, Section 27 of the Pennsylvania Constitution under the most recent court decisions interpreting the three-part test in *Payne v. Kassab*, 312 A.2d 86 (Pa. Cmwlth. 1973).

The public resource protection requirements in § 78a.15 establish a process for the Department to consider and protect public resources from the impacts of a proposed well and coordinate with public resource agencies. As such, these provisions are authorized by law and are necessary for the Commonwealth to fulfill its constitutional and statutory obligations.

Distances

Demonstrating once again how divergent opinions on the proposed rulemaking and draft pre-Act 52 final-form regulations could be, many commentators expressed concern over the distances in § 78a.15(f). Some commentators felt that the distances should be expanded. Others

believed that the measuring the distance from the limit of disturbance rather than the vertical wellbore was inappropriate because the statute only refers to impacts from the well.

The distances to certain public resources identified in § 78a.15(f)(1) of this final-form rulemaking are consistent with those used by the Department to consider public resources in well application forms since the oil and gas permitting program was established under the 1984 Oil and Gas Act. The Department has found these distances to be effective for purposes of identifying and considering potential impacts to public resources. However, given the increased size of well sites constructed when enhanced development techniques such as hydraulic fracturing are used, § 78a.15(f)(2) require these distances to be measured from the limit of disturbance of the well site rather than from the well itself, as was the prior practice.

Setbacks

Many commentators believed that the distances in § 78a.15(f) comprised setbacks and that specifically there should be a 1-mile setback from schools, nursing homes and day care facilities.

The provisions in this final-form rulemaking, however, are not setbacks. The distances in these provisions define an area that requires coordination with public resource agencies and additional consideration during the permit review process. These provisions do not prohibit drilling activities within these defined areas and were never intended to do so.

In section 3215(a) of the 2012 Oil and Gas Act, the General Assembly established setbacks prohibiting the drilling of oil and gas wells within certain distances from buildings and drinking water wells. For a conventional well, this distance is 200 feet; for an unconventional well, this distance is 500 feet. Additionally, unconventional wells may not be drilled within 1,000 feet of a public water supply. To the extent the commentators suggests that the General Assembly should extend these setbacks from certain facilities, such as schools, nursing homes or day care facilities, that change must be made through an amendment to the 2012 Oil and Gas Act.

Too much power given to the public resources agencies

A related set of commentators felt that even though § 78a.15(f) does not establish setbacks, it still gives “too much power” to the public resource agencies. The Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, The Administrative Code of 1929, the 2012 Oil and Gas Act, The Clean Streams Law, the Dam Safety and Encroachments Act, the SWMA and other statutes.

The Department has a specific statutory obligation to consider the impacts to public resources under section 3215(c) of the 2012 Oil and Gas Act. Additionally, the General Assembly established a plenary role for the Department in matters of regulating oil and gas activities which may impact public resources. Section 3202 of the 2012 Oil and Gas Act states that the purpose of the act is to “[p]rotect the natural resources, environmental rights and values secured by the Constitution of Pennsylvania.” Under section 3274 of the 2012 Oil and Gas Act, the Board has the authority to promulgate regulations necessary to implement the 2012 Oil and Gas Act.

Moreover, the Department shares responsibility for the protection of natural resources with other Commonwealth agencies and municipalities that also have trustee duties under Article I, Section 27 of the Pennsylvania Constitu-

tion, as well as Federal agencies. For example, the Department of Conservation and Natural Resources is required by statute to manage State parks and State forests, as well as to survey and maintain an inventory of ecological resources of the Commonwealth. Similarly, the Fish and Boat Commission and the Game Commission have responsibility for managing various fish and wildlife resources within this Commonwealth. Federal agencies also have jurisdiction over certain water resources, as well as Federally protected fish and wildlife resources. Further, public resources agencies have particular knowledge and expertise concerning the public resources they are responsible for managing.

Section 78a.15(f) establishes a straightforward process for well applicants to notify public resources agencies and provide those public resources agencies the opportunity to submit comments to the Department on functions and uses of the applicable public resources and any mitigation measures recommended to avoid, minimize or otherwise mitigate probable harmful impacts.

By requiring the applicant and the Department to consider recommendations from public resource agencies, this final-form rulemaking ensures that the Department meets its constitutional and statutory obligations to consider public resources when making determinations on well permits. Importantly, these provisions function to provide the Department with information necessary to enable the Department to conduct its evaluation of the potential impacts, to review the information in the context of the criteria in § 78a.15(g) and to determine whether permit conditions are necessary to prevent a probable harmful impact.

Public resources to be considered in § 78a.15(f)

A related set of comments concerned the list of public resources that trigger the impact screening process, with the thrust of the comments being that the list was too narrowly drawn and should be expanded to include other resources. Other commentators argued that the list of public resources does not mirror what is in the statute and therefore should be narrowed.

Under section 3215(c) of the 2012 Oil and Gas Act, the Department has the obligation to consider the impacts of a proposed well on public resources “including, but not limited to” certain enumerated resources when making a determination on a well permit. Accordingly, given the authority in section 3215(c) of the 2012 Oil and Gas Act as well as the Department’s constitutional and statutory obligations to protect public resources, the Department has the authority to expand the list of public resources to include public resources similar to those listed.

Section 78a.15(f)(1) of this final-form rulemaking includes the public resources listed in section 3215(c) of the 2012 Oil and Gas Act. Based on comments received, “common areas of a school’s property,” “playgrounds” and “wellhead protection areas” were added because these resources are similar in nature to the other listed public resources. Playgrounds and school common areas are frequently used by the public for outdoor recreation, similar to parks. Wellhead protection areas are associated with sources used for public drinking supplies, another listed resource. In further response to comments, the “wellhead protection area” public resource has been clarified by including a cross-reference to § 109.713 (relating to wellhead protection program) and limiting the areas to those classified as zones 1 and 2. Additionally, definitions of “common areas of a school’s property” and “playground” have been added to § 78a.1.

Notwithstanding the enumeration of specific public resources in this final-form rulemaking, the Department will consider the potential impacts to other public resources identified during the permitting process.

To the extent that commentators questioned what constitutes an impact, § 78a.15(f)(2) and (3) outlines the process for coordinating with public resource agencies and the information that a well permit applicant shall include in the well permit application to address potential impacts. The purpose of these paragraphs is to identify the public resources that may be impacted by well drilling and to outline a process to ensure the Department has sufficient information to evaluate when determining whether permit conditions are necessary to prevent a probable harmful impact to the functions and uses of those public resources using the criteria in § 78a.15(g). Accordingly, within the context of these provisions, an impact is a probable harmful effect to the functions and uses of the public resource.

A more specific set of comments recommended adding schools, hospitals, day care centers, nursing homes and other similar facilities to the list of public resources.

These facilities have not been added to the list of public resources included in § 78a.15(f)(1) of this final-form rulemaking. These types of facilities are not similar in nature to the other listed public resources (that is, parks, forests, game lands, wildlife areas, species of special concern, scenic rivers, natural landmarks, historical or archeological sites, and public drinking water supplies).

To the extent that commentators were suggesting that additional protections are needed for these facilities, Chapter 78a, as well as other regulations, permits and policies implemented by the Department under the Commonwealth’s environmental laws establish a comprehensive regulatory scheme for oil and gas well development activities to ensure protection of public health, safety and the environment.

A similar set of comments suggested that the Department add other waters of the Commonwealth to the list of public resources. Section 78a.15(f) has not been expanded in this manner because protection of these waters is achieved through other provisions in Chapter 78a, as well as implementation of other water permitting programs administered by the Department through other environmental laws and regulations. Specifically, § 78a.15(b.1) requires additional consideration during the well permit application review process for any watercourse or any high quality or exceptional value body of water or any wetland one acre or greater in size. Importantly, Chapter 78a contains many provisions, including the requirements related to erosion and sediment control, surface water discharges, waste management, onsite processing, protection of water supplies, water management planning, secondary containment, well construction and site restoration that ensure protection of waters of the Commonwealth.

Cover all oil and gas operations

Another group of comments stated that the public resource impact screening process should apply to all oil and gas operations, not merely drilling a well. The Department declined to make this change in this final-form rulemaking.

Section 78a.15 establishes the well permit application process and is limited to activities associated with well construction and development. The requirements of these sections are designed to address the impacts within the limit of disturbance of the well site. Other activities

associated with the oil and gas operations are regulated through various other provisions in Chapter 78a, or other laws implemented by the Department.

Definition of "other critical communities" exceeds the Department's legal authority

Regarding § 78a.15(f)(1)(iv), some commentators believed that the definition of "other critical communities" exceeded the Department's legal authority.

The Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, The Administrative Code of 1929, the 2012 Oil and Gas Act, The Clean Streams Law, the Dam Safety and Encroachments Act, the SWMA and other statutes. Specifically, under section 3215(c)(4) of the 2012 Oil and Gas Act, the Department has a legal obligation when reviewing a well permit application to consider the impacts to public resources including "other critical communities." The phrase "other critical communities" is defined in this final-form rulemaking to mean species of special concern identified through the PNDI consistent with the Department's past practices and policies. Under section 3274 of the 2012 Oil and Gas Act, the Board has the authority to promulgate regulations necessary to implement the 2012 Oil and Gas Act.

The Department's well permit application materials and its "Policy for Pennsylvania Natural Diversity Inventory (PNDI) Coordination During Permit Review and Evaluation," Doc. No. 021-0200-001, establish a process that has been and continues to be in use by well permit applicants to identify and consider species of special concern. This final-form rulemaking codifies this process and is consistent with the Department's long-standing use of PNDI to fulfill its responsibility to consider impacts on species of special concern when issuing permits under various environmental statutes.

In response to comments, this final-form rulemaking amends the definition of "other critical communities" in § 78a.1 to clarify that this term applies only to those species of special concern that appear on a PNDI receipt. Also in response to comments, the Department deleted the provisions in the draft final-form regulations regarding specific areas within the geographical area occupied by a threatened or endangered species and significant nonspecies resources. These changes were to ensure that this final-form rulemaking accurately reflects the existing PNDI process.

The process for consideration of public resources in § 78a.15 makes appropriate use of information available in the PNDI database from the public resources agencies with the authority, knowledge and expertise to identify and protect species of special concern. Section 78a.15(f) outlines a reasonable and appropriate process that provides important information to the Department to evaluate potential impacts and to assess the need for additional conditions in the well permit using the criteria in § 78a.15(g).

Notification to schools and evacuation provisions in operators PPC plan

A school with a common area within 200 feet of the limit of disturbance of a proposed well site will receive notice from the well permit applicant. To the extent that the commentator suggested that additional requirements are needed for emergency response, § 78a.55 contains comprehensive emergency response requirements for unconventional well sites. Plans are available to the public and county emergency management agencies.

Replace wellhead protection zone/area and wellhead protection plan with source water protection zone and source water protection plan

In response to comments that the wellhead protection area in § 78a.15(f)(1)(vii) has been clarified by adding a cross-reference to § 109.713 and limiting public resource coordination to proposed wells in zone 1 and 2 wellhead protection areas.

Several commentators suggested that "Source Water Protection Zone" and "Source Water Protection Plan" should replace wellhead protection zone and wellhead protection plan every place it appears in these chapters, allowing the inclusion of water suppliers relying on surface water sources in the notification process. The Department disagrees and declined to make this change. The wellhead protection program is established under § 109.713 and allows for an objective and identifiable area to set objective limits on the resource impact screen. The Department acknowledges that surface water sources should be protected and believes that Chapter 78a and other Department regulations and statutes provide adequate protection.

Public resource agency notification and comment period

Many commentators expressed concerns over the amount of time given in § 78a.15(f) for consultation between permit applicants and public resource agencies. Some felt that 30 days was too long and others felt that 30 days was not long enough. The Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, The Administrative Code of 1929, the 2012 Oil and Gas Act, The Clean Streams Law, the Dam Safety and Encroachments Act, the SWMA and other statutes. Moreover, the Department shares responsibility for the protection of natural resources with other Commonwealth agencies and municipalities that also have trustee duties under Article I, Section 27 of the Pennsylvania Constitution, as well as Federal agencies. The Department has a specific statutory obligation to consider the impacts to public resources under section 3215(c) of the 2012 Oil and Gas Act. Additionally, the General Assembly established a plenary role for the Department in matters of regulating oil and gas activities which may impact public resources. Section 3202 of the 2012 Oil and Gas Act states that the purpose of the act is to "[p]rotect the natural resources, environmental rights and values secured by the Constitution of Pennsylvania." Under section 3274 of the 2012 Oil and Gas Act, the Board has the authority to promulgate regulations necessary to implement the 2012 Oil and Gas Act. Coordination by the applicant with other public resource agencies with statutory authority over certain public resources is necessary and appropriate to ensure the Department fulfills its constitutional and statutory obligations.

Section 78a.15(f)(2) has been revised to increase the time provided to public resource agencies to provide comments to the Department on the impacts to public resources from 15 days to 30 days. This additional time allows municipalities that only meet on a monthly basis the opportunity to respond to a request from an applicant. The additional time also provides public resource agencies with a greater ability to review and to provide meaningful comments and recommendations to the applicant without unduly delaying the permitting process.

The operator should not be made to speculate on the functions and uses of public resources

Section 78a.15(f) establishes a process for the applicant to obtain information from an appropriate public resource

agency regarding potential impacts to public resources from the proposed oil or gas well drilling. This process ensures that the Department has sufficient information to evaluate whether permit conditions are necessary using the criteria in § 78a.15(g).

If a public resource agency does not provide any comments or recommendations when notified of a proposed oil or gas well, the Department will consider information provided by the applicant on potential impacts and proposed avoidance or mitigation measures, as well as other information available to the Department, to determine whether any well permit conditions are appropriate.

Define/clarify “discrete area”

The Department declines to define “discrete area” at this time because defining that area is an intensely site-specific determination not easily captured in regulatory language. If the need for further clarification becomes apparent during implementation of this provision, the Department will develop guidance to address any issues identified.

Criteria upon which permit conditions can be established

Section 78a.15(g) has been amended to clarify the criteria the Department will consider when deciding whether to condition an oil or gas well permit based on impacts to public resources.

Placing the burden on the Department to show that permit conditions are necessary to protect against probable harms is profoundly improper

Section 78a.15(g) has been revised to delete language regarding the Department’s burden of proof upon appeal of a condition necessary to protect a public resource. Section 3215(e) of the 2012 Oil and Gas Act states that the Department has the burden of proving that a well permit condition imposed to protect a public resource is necessary to protect against a probable harmful impact of the public resource.

Section 78a.15(g) provides that the Department may condition a well permit if it determines that the proposed well site or access road poses a probable harmful impact to a public resource. Section 3215(e) of the 2012 Oil and Gas Act requires the Department to consider the impact of the permit condition on the applicant’s ability to exercise its property rights to ensure optimal development of the resources, and provides a mechanism by which the operator may appeal the Department’s determination.

Antidegradation

Section 78a.15(h) requires a well permit applicant proposing to drill a well that involves 1 to 5 acres of earth disturbance over the life of the project that is located in a special protection watershed to submit an erosion and sediment control plan with the well permit application. These provisions seek to codify an existing component of the well permit application and are necessary to ensure that the Department’s meets its antidegradation requirements in Chapter 93.

§ 78a.18. Disposal and enhanced recovery well permits

Several commentators noted that it is possible for an unconventional well to undergo a change in service and be converted to a disposal or enhanced recovery well. Because these wells are by definition conventional wells, the Department added a cross-reference in § 78a.18 (relating to disposal and enhanced recovery well permits) to § 78.18.

The Department received many comments on this section of the nature of banning underground injection of oil and gas wastewater or making amendments to the substantive subsurface requirements of the section. The proposed amendments to the underground injection control (UIC) well provisions of Chapter 78 were not intended to represent a sweeping overhaul of the UIC program in this Commonwealth but rather to clarify that all containment practices and onsite processing associated with disposal and enhanced recovery wells had to comply with the requirements of Chapter 78. For that reason, broad amendments to the current UIC program are beyond the scope of this final-form rulemaking.

The Department also notes that the Commonwealth does not have primacy for the UIC program in this Commonwealth; that authority lies with the United States Environmental Protection Agency (EPA), Region III. The EPA program regulations are authorized by the Safe Drinking Water Act (42 U.S.C.A. §§ 300f—300j-26) and are designed to protect all underground sources of drinking water from all waste injection activities.

§ 78a.51. Protection of water supplies

In this final-form rulemaking, § 78a.51(d)(2) provides that a restored or replaced water supply will be deemed adequate if it meets the standards established under the SDWA or “is comparable to the quality of water that existed prior to pollution if the water quality was better than these standards.” This provision is needed to clarify the Department’s interpretation of the water supply replacement standard established in section 3218(a) of the 2012 Oil and Gas Act. This water supply replacement standard was newly added to as part of the 2012 Oil and Gas Act.

Many commentators argued that use of “exceeded” in section 3218(a) of the 2012 Oil and Gas Act should be interpreted to describe a water supply that does not meet SDWA standards instead of using “exceeded” to describe a water supply that had water quality better than SDWA standards. The impact of this interpretation would be that water supplies where water quality was documented prior to being affected by oil and gas activities as being higher quality than required by the SDWA would only require restoration to SDWA standards. Additionally, water supplies that did not meet SDWA standards prior to being impacted by oil and gas operations would only require restoration to the previous poor quality. The Department disagrees with this interpretation.

This final-form rulemaking requires water supplies to be restored to SDWA standards or better. The SDWA standards are based on scientific fact as far as what is, and is not, in a water supply to determine if it is safe for human consumption. If the water quality has been documented prior to being affected by oil and gas operations, that documented water quality, even if it is of a higher quality than SDWA standards, shall be re-established by the operator. Otherwise, the Department will be allowing operators to degrade a natural resource relied upon as a water supply source. In regard to water supplies that did not meet SDWA standards prior to being impacted by oil and gas operations, the Department would be derelict in its duties if it allowed operators to provide replacement drinking water that by its own standards is not fit to drink simply because the pre-existing water supply was poor. The operator may choose the size and scope of their predrill water supply survey to help bolster their defense of what the pre-existing water quality truly was. Given the need to provide replacement water based on the positive impact determination, the additional cost borne

by operators is limited to the incremental cost of providing SDWA standards water as compared to the previous poor quality, not the difference between providing no water at all and meeting the previous poor quality.

Section 78a.51(c) provides that the presumption established in section 3218(c) of the 2012 Oil and Gas Act does not apply to pollution resulting from well site construction. This provision is needed to clarify the Department's interpretation of the scope of the presumption in the statute. Several commentators argued that the presumption should apply to well site construction. The presumption encompasses situations in which the water supply is within 2,500 feet of the unconventional well bore, and the pollution takes place within 12 months of drilling, alteration or stimulation of an unconventional well and situations in which the water supply is within 1,000 feet of the conventional well bore, and the pollution takes place within 6 months of drilling or alteration of a conventional well. The Department does not have regulatory authority to expand the scope of the statutory presumption to include well pad development. If the Department finds that the pollution or diminution was caused by the well site construction, drilling, alteration or other oil and gas operations, or if it presumes the well operator is responsible for pollution under section 3218(c) of the 2012 Oil and Gas Act, the Department will require the operator to provide a temporary water supply to the landowner or water purveyor until the water supply is permanently restored or replaced.

Section 78a.51(a) specifies that a water supply owner may notify the Department and request an investigation if suffering pollution or diminution of a water supply. This provision is needed to clarify the scope of water supply complaints. Many commentators argued that the Department does not have authority to expand water supply pollution or diminution investigations to include oil and gas operations. While section 3218(b) of the 2012 Oil and Gas Act states that a landowner or water purveyor suffering pollution or diminution of a water supply as a result of the drilling, alteration or operation of an oil or gas well may so notify the Department and request that an investigation be conducted, the Department also has a responsibility to investigate all possible water supply impacts under The Clean Streams Law, including those caused by oil and gas operations. Therefore, the Department included oil and gas operations in the scope of reasons an affected landowner, water purveyor or affected person may request a water supply investigation from the Department.

Some commentators have suggested the Department specifically notify neighboring land owners or land management agencies, or both, if a claim of water pollution or diminution has been made to the Department. The Department declined to make this suggested change because the Department administers a robust program to prevent and respond to complaints and spills and releases associated with oil and gas activities. When the Department concludes that a water supply may be impacted by a spill, the Department routinely provides notice to those persons potentially impacted and gathers additional information to aid further investigation if warranted. The investigation may include sampling water supplies that are potentially impacted by a spill (if permission is obtained from the water supply owner) based on the circumstances of the spill, including the physical and hydrogeologic environment and the type and size of the spill. Each investigation related to a spill varies depending on the circumstances involved. For that reason, the

Department determined that the suggested change was not appropriate to be added to this final-form rulemaking at this time.

Many commentators argued that the Department should lessen the 10-day time frame afforded to it in section 3218(b) of the 2012 Oil and Gas Act to investigate a water supply since impacts to water supplies are both spatial and temporal. While the Department cannot change the statutory language, it is committed to investigate all claims of water supply pollution or diminution in a timely manner. This commitment can be found in Department policy *Standards and Guidelines for Identifying, Tracking, and Resolving Oil and Gas Violations*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 820-4000-001, revised January 17, 2015.

§ 78a.52. *Predrilling or prealteration survey*

Section 3218(c) of the 2012 Oil and Gas Act establishes a presumption of liability for an operator who impacts a water supply located within a certain distance from the wellbore and within a certain time frame. Section 3218(d)(1)(i) of the 2012 Oil and Gas Act allows an operator to rebut the presumption by proving that "the pollution existed prior to the drilling or alteration activity as determined by a predrilling or prealteration survey." The Department received significant public comment that the regulation should include a specific list of potential contaminants that shall be analyzed for in each predrilling or prealteration survey.

The Department believes that the General Assembly chose to place the onus of not conducting a predrill survey on the backs of operators, who might not be able to rebut a presumption of liability if a water supply is not sampled prior to drilling or a particular substance is not tested for by the operator. By failing to establish predrill water quality, the operator opens itself up to liability for any failure to meet drinking water standards in any water supply located within the presumption's radius for any substance found in the water supply. Therefore, presumption is more protective of water supplies than a prescribed list of contaminants to be sampled for with a predrill water sample. The Department will require water supplies impacted by oil and gas operations to be restored to SDWA standards or better, based upon the predrill water supply survey results.

This final-form rulemaking allows an operator to submit a copy of all predrill sample results taken as part of a survey to the Department by electronic means. Prior to this final-form rulemaking, operators were required to submit each individual's sample by mail as it was completed, which was much less efficient for operators and the Department due to the comprehensive nature of the analysis and the way analyses are completed. The Department received significant public comment regarding the time frames under which this information was required to be submitted. This final-form rulemaking allows all sample results pertaining to the well of concern to be submitted to the Department by the operator 10 days prior to the start of drilling of the well in a single coordinated report. The Department believes that this change allows this portion of this final-form rulemaking to strike an appropriate balance between being reasonable and protective of public health and safety and the environment. The Department does not believe that it is appropriate to accept sample results as predrill samples after oil and gas activity has begun.

Availability of data to the public

Many commentators argued that the Department should make all predrill sample results available to the public. The Department does not provide predrill data to the public, unless all identifying information is redacted, to protect the privacy and rights of the property owners.

*§ 78a.52a. Area of review**§ 78a.73. General provision for well construction and operation*

Because the requirements in § 78a.52a and § 78a.73 (relating to general provision for well construction and operation) are so intertwined, the Department will address changes to these sections and the comments received on them together.

Pre-hydraulic fracturing surveys

The Department estimates that there are approximately 300,000 abandoned wells across this Commonwealth. A serious risk to waters of the Commonwealth is posed when an operator inadvertently alters an abandoned well by inducing hydraulic or pressure communication during the hydraulic fracturing process. Altering an abandoned well by subjecting it to pressures and reservoir sections it was not necessarily built to isolate can and has led to a number of issues, including methane migration and water supply impacts. Even in instances when water supplies are not affected, communication with any adjacent oil or gas well has the potential to lead to well control incidents that may pose serious safety hazards.

In addition, STRONGER reviewed the Commonwealth's oil and gas program in 2010 and 2013. Although generally complementary of the Commonwealth's program, among other suggestions the reviews did urge the Department to "require operators to evaluate and mitigate potential risk of hydraulic fracturing communication with active, abandoned or orphan wells and other potential conduits that penetrate target formation or confining formations above (STRONGER Guidelines Section 9.2.1)." 2013 STRONGER Report, pages 51 and 52. It is important to note that the STRONGER recommendation on this topic did not make any distinction between hydraulically fracturing a conventional or unconventional well.

Section 78a.52a of this final-form rulemaking require operators to identify abandoned, orphan, active and inactive wells within 1,000 feet of the vertical and horizontal wellbore prior to hydraulic fracturing. The review distance is set at 500 feet for vertical oil wells in § 78.52a. The identification process requires operators to review the Department's orphan and abandoned well database, review farm line maps and submit a questionnaire to landowners whose property lies within the prescribed area of review prior to drilling in cases where hydraulic fracturing activities are anticipated at the well site. Other available databases and historical sources shall also be consulted.

Section 78a.73 indicates which subset of the identified wells shall be monitored based on vertical proximity to the stimulated interval. Wells that penetrate within defined vertical separation distances have the potential to serve as preferential pathways allowing pollution of the waters of the Commonwealth. Monitoring protocols will be based on the level of risk posed by individual well sites within the area of review and represent a mechanism for minimizing or altogether eliminating the potential for any lasting environmental impacts or other safety hazards.

Section 78a.52a also accounts for scenarios where access to well sites may be limited or previously unidentified geologic features may affect hydraulic fracturing activities through the introduction of provisions that require operators to monitor treatment pressures and volumes during stimulation activities. Monitoring allows practical operational flexibility with regard to the mechanisms available for the identification of fracture propagation possibly representative of a communication event.

When communication incidents are not observed immediately, the extent of the environmental impacts may be more severe. Remediation activities, such as stream diversions, the installation and maintenance of treatment systems, and repairs to affected wells or plugging activities are costly and may require operators to finance projects over the course of several years. For example, workover reports submitted to the Department in association with an ongoing stray gas migration case in northeastern Pennsylvania document well repairs amounting to tens of thousands of dollars a day. Depending on when a communication is noted, future wells may be drilled that are not considerate of open communication pathways. These wells may have to be abandoned prematurely or certain fracture stages may have to remain unstimulated, thus reducing the economic value of the new well and the efficiency of resource recovery. This final-form rulemaking strikes a reasonable balance between the costs of conducting the area of review survey and monitoring offset wells and the benefit associated with avoiding communication incidents. This benefit will be realized by operators and the citizens of this Commonwealth.

To further elaborate on one notable consequence of communication incidents, it is important to note that hundreds of documented stray gas migration investigations have taken place during the modern era of oil and gas development in this Commonwealth, that is, between 1984 and the present day. Prior to passage of the 1984 Oil and Gas Act, it is difficult to speculate at what frequency these incidents occurred. A subset of these incidents has been directly attributed to communications with abandoned wells during hydraulic fracturing. In association with a certain number of the total recorded stray gas migration incidents in this Commonwealth, water supplies have been impacted for periods extending over several years. In some cases, property damage has resulted and lives have been lost due to the characteristics of methane gas under certain conditions.

Final-form § 78a.52a, which requires operators to document due diligence in a consistent manner and report unanticipated communication incidents that occur in a systematic way, will have far-reaching benefits and minimal costs. Addressing this particular issue has been supported by the STRONGER organization, and comports with the 2012 Oil and Gas Act, which intends that oil and gas wells be constructed in a way to prevent gas and other fluids from entering sources of fresh groundwater.

§ 78a.53. Erosion and sediment control and stormwater management

The Department added cross-references to this final-form rulemaking to two additional Departmental guidance documents addressing issues regarding erosion and sediment control.

§ 78.55. Control and disposal planning

In this final-form rulemaking, § 78.55 is amended to delete subsection (f), which related exclusively to emergency response planning for unconventional wells. This is

the only change to this section retained in this final-form rulemaking at the direction of the Office of Attorney General during its review of the pre-Act 52 final-form regulations for form and legality.

§ 78a.55. Control and disposal planning; emergency response for unconventional wells

Section 78a.55 of this final-form rulemaking requires all well operators to develop and implement a site-specific PPC plan for oil and gas operations. This change is needed clarify requirements in §§ 91.34 and 102.5(l). Additionally, site-specific PPC plans are needed to address the conditions present at each individual site, including local emergency contact information.

There may be instances when the operator finds that a PPC plan prepared for one well site is applicable to another site. For example, conventional well sites that are all located in a single municipality with similar equipment present on each site might be able to “share” a single PPC plan that still nonetheless addresses the concerns facing each site. Each individual plan shall be analyzed prior to making a determination. It is not the intent of this final-form rulemaking to require each PPC plan be separately developed and different for each well site. The Department understands that many of the practices covered in the PPC plan are the same for a given operator. It is also not the intent of this final-form rulemaking to require that all PPC plans are revised annually. In many cases, if conditions at the site do not change, there will be no need to make revisions to the PPC plan.

Commentators expressed concerns about § 78a.55(a) which simply reiterates the requirements already existing in §§ 91.34 and 102.5(l). Since § 78a.55(a) does not establish any new requirements, this subsection does not present any new burden on operators, yet referencing these requirements in Chapter 78a has value in reminding operators of those obligations. Operators may develop a single integrated PPC plan to satisfy the requirements of § 78.55(b). PPC plans satisfying the requirements of § 91.34 alone may not also satisfy the requirements of § 102.5(l). PPC plans are required for production and storage of pollutants as well as for pipelines and processing. This final-form rulemaking does not exempt the requirements of either § 91.34 or § 102.5(l) for unconventional activities. The purpose of § 78a.55 as it relates to PPC planning is largely to cross-reference existing requirements in other regulatory chapters implemented by the Department.

For these reasons, the Department has retained the requirement to develop and implement site-specific PPC plans in this final-form rulemaking.

It appears that commentators incorrectly assumed that every single site where an impoundment, production, processing, transportation, storage, use, application or disposal of pollutants occur must have the PPC plan posted onsite at all times. This final-form rulemaking does not require persons to post PPC plans at these sites at all times. This final-form rulemaking does not require a PPC plan for the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants to be maintained on the site at all.

Instead, § 78a.55(e) requires well operators to maintain a copy of the PPC plan at the well site during drilling and completion activities only. This requirement is needed because the site is active during drilling and completion activities and there is an increased risk of a spill, release or other incident. In the event of an incident, the purpose

of the onsite PPC plan is to allow the operator to quickly minimize any impact. The Department recommends well operators to maintain the PPC plan on the site whenever active operations are occurring on the well site, including during alteration and plugging activities.

Section 78a.55(e) also requires well operators to provide the PPC plan to the Department, the Fish and Boat Commission or the landowner upon request. The requirement to provide the PPC plan to the Fish and Boat Commission upon request is needed because the Fish and Boat Commission has jurisdictional responsibilities over waters of the Commonwealth. The PPC plan enables the Fish and Board Commission investigate areas of concern that fall under its jurisdiction. The Department has determined that this is reasonable and appropriate to ensure compliance with all applicable laws. Additionally, the requirement to provide landowner a copy of the PPC plan upon request is needed because landowners have a vested interest in the contents of the PPC plan and should have access to the plan. Therefore, it is in the best interest of the landowner to be provided a copy of the PPC plan so they understand the activities and potential pollutants and how they will be controlled in the event of a spill or release.

§ 78a.56. Temporary storage

Section 78a.56 regulates temporary storage of regulated substances used or produced at the well site during drilling, altering, completing, recompleting, servicing and plugging the well. The purpose of this section is to ensure that temporary storage at the well site during these activities protects public health, safety and the environment. This section is needed to minimize spills and releases into the environment.

Many commentators expressed concern with the use of pits at unconventional well sites. Section 78a.56 of this final-form rulemaking bans the use of pits for temporary waste storage at unconventional well sites. The Department has determined that it is appropriate to remove this practice because it is not commonly used by unconventional operators. Additionally, the typical type and scope of use by unconventional operators is generally incompatible with technical standards for temporary pits prescribed under § 78.56.

Many unconventional operators have moved to utilizing modular aboveground storage structures to store water and wastewater on well sites. These structures come in many shapes, sizes and designs. The permit-by-rule structure contemplated by § 78a.56 for temporary storage on the well site does not provide adequate protection to public health and safety or the environment due to the variability of the designs of these structures. Section 78a.56 seeks to codify current requirements of Department review and approval of modular aboveground storage structures prior to their use to store regulated substances on a well site. In addition, § 78a.56 will result in more efficient implementation of current requirements by including a requirement for the Department to publish approved structures on its web site. This requirement will eliminate the need for the Department to conduct multiple evaluations of the same design and allows for a single Statewide approval. It is important to note that the Statewide approval will be applicable to the design of the structure only. Section 78a.56(a)(3) requires the operator to obtain siting approval from the Department for site-specific installation of all modular aboveground storage structures for each individual well site where use of the modular aboveground storage structure is proposed. The Department evaluates proposed modular aboveground

storage structures on a case by case basis to determine whether the proposed structure will provide equivalent or superior protection. The Department reviews not only modular designs but also site-specific construction and topographic conditions. The Department's web site will list approved modular structures but authorization of the process will still be required to ensure proper siting of the facility. This provision was originally proposed to include all modular aboveground storage structures, but in response to comments the Department amended the requirement to apply to only those structures which exceed 20,000 gallons of total capacity.

In the proposed rulemaking, § 78.56(a)(5)—(7) addressed security requirements for pits, tanks and approved storage structures and required operators to equip all tank valves and access lids to regulated substances with reasonable measures to prevent unauthorized access by third parties such as locks, open end plugs, removable handles, retractable ladders or other measures that prevent access by third parties. In addition, for unconventional well sites, a fence was required to completely surround all pits to prevent unauthorized acts of third parties and damage caused by wildlife unless an individual was continuously present at the well site. Finally, operators of unconventional well sites were required to display a sign on or near the tank or other approved storage structure identifying the contents and an appropriate warning of the contents such as flammable, corrosive or a similar warning.

The Department received significant public comment from unconventional operators that the requirements to install fences around all pits or provide continuous presence on unconventional well sites was inappropriate and would not be effective. As previously noted, the Department revised § 78a.56 to disallow the use of pits on unconventional well sites and accordingly deleted the requirement to install fencing around pits on unconventional well sites. The Department also retained the requirement to maintain signs on tanks or other approved storage structures to prevent confusion when multiple storage structures are located in close proximity on a well site, and to assist emergency response personnel in properly identifying risks at well sites.

§ 78a.57. Control, storage and disposal of production fluids

Section 78a.57 in this final-form rulemaking contains requirements that apply to permanent storage of production fluids. The purpose of this section is to ensure that storage during the production of well, when there is less activity occurring at the well site, provides protection of public health, safety and the environment. This section is needed to minimize spills and releases to the environment.

In the proposed rulemaking, § 78.57(e) banned further use of underground storage tanks and would have required unconventional operators to remove all underground storage tanks within 3 years of the effective date of the final regulations. The Department received significant public comment on this provision from unconventional operators arguing that it was inappropriate, overly burdensome and exorbitantly expensive. As a result of public comment, the Department amended § 78a.57(e) in this final-form rulemaking to allow the use of buried tanks by unconventional well site operators and does not require removal of existing buried tanks. Underground storage tanks warrant extra scrutiny because they are not as easily inspected and can provide a more direct conduit for contamination into groundwater and therefore

provisions in this final-form rulemaking require the location of all existing and any new underground storage tanks at well sites to be reported to the Department.

Corrosion control

Section 78a.57(f) implements section 3218.4(b) of the 2012 Oil and Gas Act, which requires that permanent aboveground and underground tanks comply with the applicable corrosion control requirements in the Department's storage tank regulations. Some commentators argued that these provisions should not apply because storage tanks on well sites are not permanent. In the context of tanks regulated under § 78a.56, the Department agrees because those tanks are used only during drilling and completion of the well and are subject to the well site restoration time frames. However, in the context of tanks regulated under § 78a.57 for the storage of production fluids, the Department disagrees. These tanks are in place on the well site for the duration of the productive life of the well which can be decades or in some cases centuries. If tanks that are in service for this duration are not considered permanent, then no tank would ever be considered permanent under this interpretation. Accordingly, the tanks regulated by § 78a.57 are permanent and subject to the corrosion control requirements in section 3218.4(b) of the 2012 Oil and Gas Act.

Commentators also argued that because the Storage Tank and Spill Prevention Act (35 P.S. §§ 6021.101—6021.2104) specifically exempts underground and aboveground storage tanks located at oil and gas well sites from regulation, there are no applicable corrosion control requirements in the Department's storage tank regulations. Therefore, regulations specifying that operators shall comply with corrosion control requirements in §§ 245.432 and 245.531—245.534 are inappropriate and not authorized by section 3218.4(b) of the 2012 Oil and Gas Act. The Department disagrees with this interpretation. Section 3218.4(b) of the 2012 Oil and Gas Act expressly requires permanent aboveground tanks to comply with the applicable corrosion control requirements in the Department's storage tank regulations. Additionally, section 3218.4(b) of the 2012 Oil and Gas Act was enacted after the Storage Tank and Spill Prevention Act.

The Department notes that this final-form rulemaking does not require retroactive application of the corrosion control requirements. Only new, refurbished or replaced aboveground and underground storage tanks must comply with the applicable corrosion control requirements. In addition, the Department also explicitly deleted the requirement to use Department certified inspectors to conduct inspections of interior linings or coatings as not "applicable," which will alleviate some burden on oil and gas operators. Finally, the Department notes that operators may choose to use nonmetallic tanks which can often be less expensive than a steel equivalent and do not require any additional cost to ensure protection from corrosion.

Secondary containment

Section 78a.57(c) of this final-form rulemaking requires secondary containment for aboveground tanks that contain brine and other fluids produced during operation of the well. Since well sites in the production phase are not typically inspected by the Department with the same frequency as those in the well development, restoration and plugging phases, and do not have continuous operator presence, the Department feels it is necessary to require secondary containment for aboveground tanks

used to store brine and other fluids produced during operation of the well to prevent undetected releases into the environment.

Releases of brine from aboveground tanks used for production fluids are uncontrolled and usually undetected as they occur. Secondary containment around aboveground tanks will prevent these releases from entering the environment until they are detected.

To reduce the burden on operators, this final-form rulemaking does not require retroactive application of the secondary containment requirements. The Department does not require secondary containment to be installed until a tank or one tank in a series of tanks is added, refurbished or replaced. Finally, commentators raised the concern of a larger footprint created by secondary containment where available area may be an issue. This concern is addressed by allowing the use of double-walled tanks capable of detecting a leak in the primary containment to fulfill the requirements in this subsection.

§ 78a.58. *Onsite processing*

Section 78a.58 codifies existing practices to allow onsite waste processing to occur provided all of the waste processed on the site is either generated at the site or will be beneficially reused at the site after approval is obtained from the Department. The purpose of this provision is to encourage recycling and reuse in hydraulic fracturing operations. These provisions are needed to ensure that processing activities are conducted in a way that protects public health, safety and the environment. Additionally, the purpose of these provisions is to minimize spills and releases to the environment.

This final-form rulemaking also seeks to streamline this process by including a requirement for the Department to publish approved processes on its web site. This requirement will eliminate the need for the Department to conduct multiple evaluations of the same process and allows for a single Statewide approval. Once a process receives approval, operators wishing to utilize that process would be required only to register use and provide notification to the Department 3 days prior to initiating processing. These sections also include exemptions from the requirement to obtain approval and register with the Department prior to conducting the following processes: blending wastewater with fresh water, aeration and filtering solids from fluids. The Department does not believe that specific Department oversight is necessary for these processes.

The Department received significant public comment on this section indicating that allowing operators to conduct waste processing on well sites is inappropriate and not protective of public health and safety or the environment. The Department disagrees and believes that it is appropriate to allow waste processing on a well site to facilitate beneficial reuse of waste and efficient operations, so long as appropriate protections are in place as required by these amendments.

The Department received comments that requiring an operator to wait for solid waste remaining after the processing or handling of fluids under § 78a.58 be characterized under § 287.54 (relating to chemical analysis of waste) before the solid waste leaves the well site requires too much time (27 days) to store it onsite until the sample analysis is received. The Department requires that a waste characterization be conducted in accordance with § 287.54. The Department believes that this is an appropriate cross-reference, as § 78a.58(h) only concerns those wastes that will be leaving the well site where they were

generated. Once the waste leaves the well site, the exemptions under section 3273.1 of the 2012 Oil and Gas Act no longer apply and the waste management program regulations govern testing and handling of the waste.

Commentators also noted that waste processing often generates high concentrations of TENORM. The Department's 2015 TENORM Study Report presented several observations and recommendations regarding radioactive material associated with the oil and gas industry. Although the study outlines recommendations for further study, it concluded there is little potential for harm to workers or the public from radiation exposure due to oil and gas development. While the study concluded that there is little potential harm to workers or the public from radiation exposure due to oil and gas development, the study observed that there is potential for worker and public exposure from the processing and potential spilling of wastewater from oil and gas operations. There is also the potential to produce loads of TENORM waste with radium-226/-228 concentrations greater than 270 pCi/g, which is the threshold for United States Department of Transportation regulations regarding the labelling, shipping and transport of Class 7 hazmat radioactive material.

The Department remains committed to protecting the public from unnecessary exposure to radiation and is actively pursuing the recommendations of the 2015 TENORM Study Report. The Department added § 78a.58(d) to this final-form rulemaking. This new subsection requires an operator processing fluids onsite to develop a radiation protection action plan which specifies procedures for monitoring and responding to radioactive material produced by the treatment process (for example, sludges or filter cake). This section also requires procedures for training, notification, recordkeeping and reporting to be implemented. This will ensure that workers, members of the public and the environment are adequately protected from radioactive material that may be found in fluids processed on the well site.

Other commentators indicated that this section is overly burdensome and does not go far enough to support processing, recycling and beneficial reuse of fluids and other waste materials at well sites. It is the intent of this section to support waste processing on a well site to facilitate beneficial reuse of waste and efficient operations; however, certain activities present enough of an environmental hazard that the Department should have the opportunity to review and approve those activities prior to implementation.

§ 78a.59a. *Impoundment embankments*

§ 78a.59b. *Well development impoundments*

In this final-form rulemaking, §§ 78a.59a and 78a.59b (relating to impoundment embankments; and well development impoundments) establish construction standards for well development impoundments. Currently, oil and gas operators use impoundments to store freshwater and other fluids approved by the Department for use in drilling and hydraulic fracturing activities that do not trigger the permitting requirements in § 105.3(a)(2) and (3) and are unregulated by the Department. The provisions in these sections seek to outline the necessary requirements to ensure that those facilities that do not meet the Chapter 105 permitting requirements have structural integrity and do not pose a threat to waters of the Commonwealth. This is necessary because the scope and type of use of well development impoundments by the oil and gas industry are significantly different than the

scope and type of use by other industries. The Department has observed the use of these impoundments to hold up to 16 million gallons of freshwater and other approved fluids varying in quality that are usually not indigenous to the local watershed where these facilities are constructed. For this reason, the escape of that water may pose a threat of pollution to waters of the Commonwealth.

The Department's structural standards and measures in §§ 78a.59a and 78.59b are intended to prevent leaking of well development impoundments in the groundwater and surrounding surface waters. Failure to construct well development impoundments in a structurally sound manner would allow for the potential for a catastrophic failure of the impoundment that may cause serious harm to public health and to the environment.

Section 78a.59b(d) and (f) specifies that an impervious liner must be used and the bottom of the well development impoundments must be placed be at least 20 inches above the seasonal high groundwater table to prevent groundwater infiltration. The Department received comments stating that well development impoundments should be required to follow Chapter 105. The Department disagrees because these regulations only pertain to dams that are not regulated under Chapter 105 because they do not meet the height and volume thresholds. The Department also received comments saying that the regulations for well development impoundments unfairly target the oil and gas industry. The Department disagrees and believes that adherence to § 78a.59a provides for the structural integrity of the impoundment to provide adequate public safety and that § 78a.59b provides reasonable assurances that the water placed in the impoundments does not pose an environmental hazard. Failure to construct well development impoundments in a structurally sound manner would allow for the potential for a catastrophic failure of the impoundment that may cause serious harm to public health and to the environment.

This final-form rulemaking also establishes registration of existing and future well development impoundments with the Department electronically through its web site. This is needed to allow the Department to inspect the well development impoundments, especially those that do not require an erosion and sediment control permit under Chapter 102.

Also, this final-form rulemaking establishes that well development impoundments need to be restored within 9 months of completion of hydraulic fracturing of the last well serviced by the impoundment. An extension for restoration may be approved under § 78a.65(c). While extensions for well development impoundments are not directly addressed in Act 13, the Department believes it is reasonable to tie the restoration requirements associated with well sites to well development impoundments because well development impoundments are contingent on the existence of well sites being developed and should not exist in perpetuity on their own. The Department believes that the sites used for well development impoundments need to be returned to preconstruction contours and support the prior land uses that existed to the extent practicable. Land owners may request to the Department in writing that the impoundment embankments not be restored provided that the synthetic liner is removed.

Technical adjustments

Several changes to this section in this final-form rulemaking include technical adjustments of the requirements. In § 78a.59a(a)(5), soil classification sampling rates are adjusted from one sample per 1,000 cubic yards

to one sample per 10,000 cubic yards which is a more appropriate sampling rate. A requirement is also added to § 78a.59a(a)(5) to describe and identify soils used for embankment construction in accordance with ASTM D-2488—09A (Standard Practice for Description and Identification of Soils (Visual-Manual Procedure)).

Soil compaction standards are included in § 78a.59a(a)(8)(iv) of this final-form rulemaking, with reference to several ASTM test methods. The Department also added language in § 78a.59a(b) allowing an operator to request a variance from the specific technical requirements in these sections upon demonstration that the alternate practice provides equivalent or superior protection to the requirements of the section.

Mine influenced water

In § 78a.59b(h), this final-form rulemaking allows operators to request to store MIW in well development impoundments. This provision seeks to codify the existing practices outlined in the Department's white paper "Establishment of a Process for Evaluating the Proposed Use of Mine Influenced Water (MIW) for Natural Gas Extraction." Further, the purpose of these provisions is to promote the voluntary use of MIW by the oil and gas industry.

Some commentators were concerned about the potential to allow operators to store MIW in well development impoundments. These commentators asserted that the quality of MIW varies greatly throughout this Commonwealth and the term includes MIW that has been treated, which may be very high quality. The Department disagreed with these commentators because § 78a.59b(h) specifies that before MIW is allowed to be stored in a well development impoundment, the Department will review and approve the storage based on a variety of factors including the quality of the MIW and the risks of storage of the water. MIW that does not meet the Department's water quality standards to be stored in a well development impoundment may not be stored in a well development impoundment absent additional protections and evaluation. The Department believes that allowing the use of MIW for well development has a positive impact on the environment by finding a beneficial use for MIW that also reduces the consumption of freshwater from the Commonwealth's waterways. In some cases, use of MIW by the oil and gas industry can provide funding for treatment systems to continue operating. Encouraging the use of alternative water sources, including recycled water, MIW and treated wastewater, has been supported by the STRONGER organization to provide additional sources of water for operators to use for well development purposes.

Security issues (fences)

Section 78a.59b(e) of this final-form rulemaking requires that a fence must completely surround a well development impoundment to prevent unauthorized acts of third parties and damage caused by wildlife unless an individual is continuously present at the impoundment. There were comments from operators who were concerned that no matter what type of fence they erect around an impoundment, it could never absolutely prevent entry. This provision is needed due to the size and depth of many well development impoundments plus the slickness of the installed liner. Additionally, this provision is needed to prevent unintended entry by landowners or other members of the public. Fences are also needed to deter wildlife from damaging the structural integrity of these facilities. Well development impoundment liners can easily be damaged by large animals and even smaller ones with claws trying to escape after falling in.

§ 78a.59c. Centralized impoundments

This final-form rulemaking requires all centralized impoundments to comply with permitting requirements in Subpart D, Article IX, or close by October 8, 2019. When initially proposed, this section included provisions to codify the Department's existing centralized impoundment permit program by providing technical specifications for construction and operation of centralized waste storage impoundments. The Department received significant public comment on this provision.

Commentators argued that the standards set for centralized impoundments for oil and gas operations were less stringent than other Department regulations that address closure of impoundments (for example, Chapter 289 (relating to residual waste disposal impoundments)). The Department believes that centralized impoundments should be regulated in the same manner as other waste transfer facilities in this Commonwealth. Therefore, the Department determined that all future centralized wastewater impoundments will be regulated by the Department's Waste Management Program. This section will require oil and gas operators to comply with the residual waste management regulations which contain requirements for managing residual waste properly, and these requirements apply to residual waste that is generated by any type of industrial, mining or agricultural operation. This change will ensure that the Department does not impose disparate requirements or disproportionate costs on one particular economic or extractive sector.

§ 78a.60. Discharge requirements

This final-form rulemaking continues to allow operators to discharge top-hole water or water in a pit as a result of precipitation onto a vegetated area capable of absorbing the water and filtering solids. Commentators argued the Department should ban the discharge of top-hole water for a number of reasons. This final-form rulemaking allows the discharge of top-hole water or water in a pit from precipitation only if it includes no additives, drilling muds, regulated substances or drilling fluids other than gases or fresh water. In addition, the water must meet certain water quality standards and be discharged to an undisturbed, vegetated area capable of absorbing top-hole water and filtering solids in the discharge. Top-hole water or water in a pit as a result of precipitation may not be discharged to waters of the Commonwealth except in accordance with Chapters 91—93 and 95. Land application of water in accordance with this section is not expected to cause any significant environmental impact. This provision has been in effect since Chapter 78 was initially promulgated in 1989 and the Department continues to believe that it is an environmentally sound method of dealing with this material.

§ 78a.61. Disposal of drill cuttings

Comments were received urging the Department to ban the use of all pits and to ban onsite waste disposal. The Department amended this final-form rulemaking to ban the use of pits for temporary waste storage at unconventional well sites. The Department determined that it is appropriate to prohibit this practice because it is not commonly used by unconventional operators due to the volume and nature of wastes generated at unconventional well sites. Additionally, the typical type and scope of use by unconventional operators is generally incompatible with technical standards for temporary pits prescribed under § 78.56. As a result, unconventional operators will no longer be permitted to dispose of residual waste

including contaminated drill cuttings in a pit at the well, unless the pit is authorized by a permit obtained from the Department.

The Department clarified that the cutoff for addressing drill cuttings under subsections (a) and (b) versus under subsection (c) is the cuttings above and below the surface casing seat. The former have less restrictive yet still protective disposal requirements. A requirement to give the surface landowner notice of the location of disposal was added to subsection (e). Some commentators believed that rather than require notice, the Department should require landowner consent before allowing for disposal of drill cuttings. The Department disagrees that the regulations should include a requirement for landowner permission or consent. Prior to entering into a lease agreement with the well operator, the landowner may discuss and agree upon the terms and conditions that relate to the type of operations that will occur on the property. Additionally, the Department believes that the provisions of § 78a.61 (relating to disposal of drill cuttings) are sufficiently protective that an operator meeting those requirements should not be required to obtain prior consent. The Department does believe that transparency and notice are important concerns, however, and has added language to § 78a.61 requiring operators to provide notice to surface landowners of the location of cuttings disposal or land application.

§ 78a.62. Disposal of residual waste—pits

The primary change to § 78a.62 was to take the prohibition on disposal of residual waste generated by unconventional operations in a pit that was proposed in § 78.62(a)(1) (relating to disposal of residual waste—pits) and replace it with a ban unless the operator can obtain an individual permit for the activity. Given that other generators of residual waste can obtain permits for proper disposal of residual waste, the Department did not feel that an outright ban would withstand scrutiny.

§ 78a.63. Disposal of residual waste—land application

The primary change to § 78a.63 was to take the prohibition on disposal of residual waste generated by unconventional operations through land application that was proposed in § 78.63(a)(1) and replace it with a ban unless the operator can obtain an individual permit for the activity. Given that other generators of residual waste can obtain permits for proper disposal of residual waste, the Department did not feel that an outright ban would withstand scrutiny.

§ 78a.63a. Alternative waste management

This is a catch-all section added in this final-form rulemaking indicating that an operator may seek Department approval to manage waste in a manner other than that outlined in §§ 78a.56—78a.63, provided the operator can demonstrate that the practice provides equivalent or superior protection to the requirements in these sections. The concept is embedded in several sections of this final-form rulemaking, but the Department believes that this catch-all provision will serve as a backstop to those provisions.

§ 78a.64. Secondary containment around oil and condensate tanks

Section 78.64 (relating to containment around oil tanks) requires secondary containment that meets Federal requirements under 40 CFR Part 112 (relating to oil pollution prevention) to be implemented around oil tanks to prevent the discharge of oil into waters of the Commonwealth. The Department has expanded this require-

ment to include tanks that contain condensate (light liquid hydrocarbons) because the EPA considers condensate that is liquid at atmospheric pressures and temperatures to be "oil." This final-form rulemaking change will apply to unconventional wells that produce condensate in § 78a.64.

The Department received comments both for and against the Department's deletion of language requiring secondary containment for singular tanks with a capacity of at least 660 gallons in § 78a.64. The Department revised the language in § 78a.64 in this final-form rulemaking from 660 gallons to 1,320 gallons to be consistent with Federal Spill Prevention, Control and Countermeasure Plan regulations in 40 CFR Part 112. Making this change matches the Commonwealth's requirements to the National standards for regulation of oil and condensate storage.

The Department received comments stating that "containment" was used in various contexts throughout the draft final-form regulations and was confusing. As a result, the Department added definitions for "primary containment" and "secondary containment" in § 78a.1. These terms are used in the throughout this final-form rulemaking when referring to specific types of containment.

Section 78a.64 requires that all tanks that store hydrocarbons have secondary containment by October 9, 2016, or at the time the tank is replaced, refurbished or repaired, whichever is sooner.

§ 78a.64a. Secondary containment

Section 3218.1 of the 2012 Oil and Gas Act (relating to notification to public drinking water systems) establishes the requirement for secondary containment systems and practices for unconventional well sites. As a result, the Department adds § 78a.64a in this final-form rulemaking to implement these statutory requirements for unconventional well sites.

Secondary containment at unconventional well sites shall be used on the well site when any equipment used for any phase of drilling, casing, cementing, hydraulic fracturing or flowback operations is brought onto a well site and when regulated substances are brought onto or generated at the well site. This final-form rulemaking requires that all regulated substances, except fuel in equipment or vehicles, be managed within secondary containment. The Department received comments pointing out that section 3218.2(c) of the 2012 Oil and Gas Act (relating to containment for unconventional wells) lists six specific substances that must be stored in secondary containment and that this new section broadens the scope of that statutory list to include all regulated substances, including solid wastes and other regulated substances in equipment or vehicles. The commentators asked how this expansion is consistent with the intent of the General Assembly and the 2012 Oil and Gas Act and the need for this requirement. The Department acknowledges that section 3218.2(c) of the 2012 Oil and Gas Act does list six materials that require use of containment systems when stored on an unconventional well site but disagrees with the comment because section 402(a) of The Clean Streams Law (35 P.S. § 691.402(a)) states that whenever the Department finds that any activity creates a danger of pollution of the waters of the Commonwealth or that regulation of the activity is necessary to avoid pollution, the Department may, by rule or regulation, establish the conditions under which the activity shall be conducted. Additionally, the Department believes that it is the intent

of the General Assembly to require regulated substances be stored in secondary containment by use of the language "[u]nconventional well sites shall be designed and constructed to prevent spills to the ground surface or spills off the well site" in section 3218.2(a) of the 2012 Oil and Gas Act. It has been well documented through studies and the Department's experience that the primary cause for pollution to the environment by oil and gas operations on well sites are unauthorized releases of regulated substances onto the ground. Secondary containment of all regulated substances is necessary to significantly reduce the potential for pollution on well sites.

This final-form rulemaking establishes that chemical compatibility and maximum permeability standards must be met for materials used for secondary containment at unconventional well sites. The Department received comments stating that the ASTM D5747 standard in the proposed rulemaking for testing chemical compatibility is both time consuming and expensive. Also, that it is a standard for landfill liners and may not be practicable to allow for other materials to be used that meet the maximum permeability standard. The Department changed language in this final-form rulemaking to allow for chemical compatibility testing to be determined by a method approved by the Department. This will allow for the proper and most practicable testing methodology to be used based upon the material used for secondary containment at an unconventional well site.

Secondary containment open to the atmosphere must be able to hold the volume of the largest aboveground primary container plus an additional 10% for precipitation. Removal of precipitation from secondary containment is required once the 10% of excess capacity is diminished. Stormwater that comes into contact with regulated substances stored within the secondary containment needs to be managed as residual waste. Double walled tanks capable of detecting leaks from primary containment are also allowed to be used. The Department received comments that section 3218.2(d) of the 2012 Oil and Gas Act does not require secondary containment systems. The Department interprets that section to mean that the container that additives, chemicals, oils or fuels are stored in is considered to be primary containment. Therefore, the containment capacity referred to that must be able to hold the contents of the largest container plus 10% for precipitation is secondary containment. Any other interpretation of section 3218.2(d) of the 2012 Oil and Gas Act would render the final phrase of the subsection ("...unless the container is equipped with individual secondary containment") irrelevant. Therefore, it is clearly the intent of the General Assembly that secondary containment is required by the 2012 Oil and Gas Act. The Department received comments saying that stormwater that has not been discharged or discarded from secondary containment is not residual waste. The Department disagrees because stormwater in secondary containment that also contains regulated substances is considered to be residual waste, as defined in § 287.1 (relating to definitions), whether or not the stormwater has been discharged or discarded and shall be handled and disposed of accordingly.

Secondary containment shall be inspected weekly to ensure integrity. Repairs to damaged or compromised secondary containment shall be done as soon as practicable. Secondary containment inspection and maintenance records shall be maintained and made available at the well site until the well site is restored. The Department received comments stating that for many operators it is not practical to store hard copies of inspection

reports and maintenance records at the well site. As a result, the Department should allow for operators to provide these reports electronically to the Department upon request instead. The Department believes that because containment systems will be employed during drilling, casing, cementing, hydraulic fracturing and flowback operations, it is reasonable to make inspection reports and maintenance records available at the well site, because the site is normally manned during these operations. The Department is not requiring that the hard copies shall be stored onsite, but that operators shall be capable of these reports being made available upon request (physically or electronically) at the site at the time of the request. The Department needs these reports at the time of the inspection to determine that operators are doing their due diligence with secondary containment inspection and maintenance.

Language pertaining to subsurface containment systems in the proposed rulemaking has been deleted after receiving comments that they should not be allowed. The Department concurred that subsurface containment systems are too impractical to be employed as a secondary containment system because they are difficult to inspect and they would require remedial steps to address the contaminated material within them whenever a spill would occur.

§ 78a.65. *Site restoration*

Permanent changes to the surface of the land resulting from earth disturbance activities have the potential to cause pollution. In many watersheds throughout this Commonwealth, flooding problems from precipitation events, including smaller storms, have increased over time due to changes in land use and ineffective stormwater management. This additional flooding is a result of an increased volume of stormwater runoff being discharged throughout the watershed. This increase in stormwater volume is the direct result of more extensive impervious surface areas, combined with substantial tracts of natural landscape being converted to lawns on highly compacted soil or agricultural activities. The problems are not limited to flooding. Stormwater runoff carries significant quantities of pollutants washed from the impervious and altered land surfaces. The mix of potential pollutants ranges from sediment to varying quantities of nutrients, organic chemicals, petroleum hydrocarbons and other constituents that cause water quality degradation.

Improperly managed stormwater causes increased flooding, water quality degradation, stream channel erosion, reduced groundwater recharge and loss of aquatic species. These and other impacts can be effectively avoided or minimized through better site design that minimizes the volume of stormwater generated and also requires treatment. PCSM requirements are already in § 102.8 and are needed to prevent pollution from improperly managed stormwater, and require utilization of stormwater management techniques that achieve stormwater runoff volume reduction, pollutant reduction, groundwater recharge and stormwater runoff rate control for all runoff events. The requirements of § 78a.65 are not more or less stringent than § 102.8, but are a reasonable approach to adapting the requirements of this section where needed for the industry detailed as follows.

Section 78a.65 was essentially re-written after the first public comment period because as the Department considered all comments suggesting more stringent site restoration requirements as well as those against parts of the site restoration section, or the section in its entirety, it

became exceptionally difficult to read through as the significantly edited language sacrificed readability with excessive strikethrough, underlining, all capitalized text, and the like. The Department decided there needed to be a clean write-up of the restoration requirements to be understood. However, substantively, the actual changes to the site restoration section do not deviate greatly from the proposed rulemaking.

Several commentators were of the opinion that the proposed restoration requirements included in this final-form rulemaking were not stringent enough and should require more than restoration to approximate original conditions. These commentators wanted to see the restoration requirements require operators to re-establish prior existing biological communities and ecosystems as well as re-establish the entire site to its exact pre-existing conditions. This position proposed making § 78a.65 more stringent than § 102.8. The Department does not believe that it is necessary to include technical performance standards including requirements for type and density of perennial vegetation, soil characteristics and drainage patterns in this section because those issues are already appropriately addressed by the requirements. Projects meeting the requirements will not pose a threat of significant environmental harm. Projects that trigger the Chapter 102 requirements for an erosion and sediment control permit shall submit a Site Restoration/Post-Construction Stormwater Management Plan to the Department for review and approval prior to construction of the site. Additionally, this section requires operators to submit a well site restoration report to the Department 60 days after restoration. When this report is submitted, the Department conducts an inspection to ensure that the restoration requirements have been met.

This section largely restates the restoration requirements in section 3216 of the 2012 Oil and Gas Act and incorporates the Department's interpretation of these requirements as outlined in the *Policy for Erosion and Sediment Control and Stormwater Management for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 800-2100-008, which was finalized on December 29, 2012. It is unreasonable to interpret the restoration requirements in the 2012 Oil and Gas Act to require restoration of the well site to a different standard depending upon whether or not a restoration extension has been granted. The Department included the phrase "to the extent practicable" in the definition of "approximate original conditions" in § 78a.1 in recognition of the fact that restoration to original contours may not always be feasible. Section 78a.65(a)(1) allows operators broad discretion to ensure wells and well sites can be operated safely while also complying with the site restoration requirements in the 2012 Oil and Gas Act.

Restoration timeline/2-year extension

The restoration time frame is consistent with requirements in the 2012 Oil and Gas Act. Operators may request an extension of the restoration time frame because the extension will result in less earth disturbance, increased water reuse or more efficient development of the resources, or if restoration cannot be achieved due to adverse weather conditions or a lack of essential fuel, equipment or labor.

For post-drilling, this final-form rulemaking requires restoration of the well site within 9 months after completion of drilling of all permitted wells on the site or within

9 months of the expiration of all existing well permits on the site, whichever is later. For post-plugging, it requires restoration within 9 months after plugging the final well on a well site. The restoration time frames are consistent with requirements in the 2012 Oil and Gas Act.

Currently, a well site shall be restored within 30 days after expiration of the drilling permit, if the site is constructed and the well is not drilled. This was originally retained in the draft final-form regulations. Several comments were received from operators arguing this to be a burdensome requirement. While this may have been an appropriate time frame to restore a conventional well site, the size of an unconventional well site makes it very difficult to achieve this restoration time frame. The Department recognizes this and has changed the time frame to 9 months to be consistent with other restoration requirements.

Some operator's comments expressed concern that restoration within 9 months may not work in every situation. Under this final-form rulemaking, operators may request an extension of the restoration time frame because the extension will result in less earth disturbance, increased water reuse or more efficient development of the resources or if restoration cannot be achieved due to adverse weather conditions or a lack of essential fuel, equipment or labor. This allows the operator some flexibility while still being protective of public health and safety and the environment.

PCSM requirements

The amendments to § 78a.65 in the draft final-form regulations addressed comments on this section that expressed continuing confusion regarding what constitutes "restoration" as the term is used in Chapters 78 and 102, and what the associated requirements are. The changes to this section in this final-form rulemaking clarify these issues and, in particular, distinguish between areas not restored and other areas. "Areas not restored" do not fall within the provisions in § 102.8(n) and therefore must meet the requirements, among others, of § 102.8(g). Areas not restored include areas where there are permanent structures or impervious surfaces, therefore runoff produced from these areas must be tributary to permanent PCSM BMPs to ensure the runoff will be managed in accordance with the requirements of § 102.8.

Landowner consent for storing equipment not needed for production (agreements versus lease)

Drilling supplies and equipment not needed for production may only be stored on the well site if written consent of the landowner is obtained. Several operators expressed concern that this requirement should not be necessary if they have an executed lease with the landowner allowing for the storage of equipment. The Department disagrees as the need for landowner consent is consistent with the requirements in section 3216 of the 2012 Oil and Gas Act. The requirement for consent allows the landowner to know what is being stored on their property, where a blanket allowance under a lease agreement may not afford transparency.

Waste disposal information in restoration report

The Department acknowledges that the current waste reporting requirements may capture some of the same information required on the restoration report but still believes that waste disposal information should be included in the site restoration report. Details regarding the type of waste, as well as volume, leachate analysis and physical location are not captured in the waste

reporting requirements. This information is critical for the landowner to be aware of where waste is located so it can be avoided in the event of future earth moving activities on the landowner's property.

§ 78a.66. Reporting and remediating spills and releases

Spills or releases from containment of regulated substances at oil and gas well sites pose a substantial risk to the environment and public health, including impacts to water resources. Oil and gas operators of both conventional and unconventional wells have an obligation to report and properly remediate spills and releases in a timely manner.

Several commentators felt that it was inappropriate to require cleanups of spills and releases under Act 2 because the 2012 Oil and Gas Act is not one of the environmental statutes referenced in Act 2. Act 2 provides a procedure to remediate and receive relief of environmental liability regarding a release of a regulated substance addressed under various environmental statutes, including The Clean Streams Law, the SWMA and the Hazardous Sites Cleanup Act (35 P.S. §§ 6020.101—6020.1305). Many substances that are spilled at sites regulated under the 2012 Oil and Gas Act are regulated as waste under the SWMA or as pollutants under The Clean Streams Law (see, for example, section 3273 of the 2012 Oil and Gas Act (relating to effect on department authority) and section 3273.1 of the 2012 Oil and Gas Act). If these wastes and pollutants are regulated substances as defined under Act 2 and have contaminated soils and groundwater, they must be addressed under Act 2, regardless of the nature of the activity that resulted in contamination.

Some commentators felt that reporting requirements in § 78a.66(b)(2) went beyond the scope of what is required in § 91.33. The Department believes that subsection (b)(2) in this final-form rulemaking will serve as guidance for the responsible party to provide enough information, to the extent known, necessary for the Department to properly assess the reported spill incident, so the appropriate initial response can be employed by the Department.

Many commentators were concerned that the public and other government agencies were not made aware of all spills and releases that occur at unconventional well sites. The regulations require that operators report releases within 2 hours of discovery to the Department electronically through its web site. This information will then be loaded directly into a spill and release database. The Department will utilize this database to create an electronic spill and release reporting and tracking system available for the public and government entities to receive up-to-date information concerning spills and releases and remedial actions at oil and gas operations. The system will be similar to the Department's eNOTICE system, which allows users to get information about their communities and the facilities they are interested in delivered directly by e-mail.

Section 78a.66 cross-references § 91.33, which requires the operator or other responsible party to take necessary corrective actions, upon discovery of the spill or release, to prevent the substance from polluting or threatening to pollute the waters of the Commonwealth, damage to property or impacts to downstream users of waters of the Commonwealth. This concern was expressed in numerous comments over the possible pollution of private water wells due to oil and gas activity. To help address this, the operator or other responsible party will be required to

identify water supplies that have been polluted or for which there is potential for pollution as a result of a spill or release at a conventional or unconventional well site. If a water supply is determined to have been polluted, it shall be restored or replaced in accordance with § 78a.51.

The spill or release area shall then be remediated appropriately through Act 2 standards and processes. One of the primary reasons the Department requires remediation of spills to an Act 2 standard is because the operator is typically not the owner of the land where the regulated substance is spilled or released. It is simply unreasonable to leave behind contaminants at levels that may pose a health risk as a result of oil and gas operations on another person's property.

The Department's Act 2 standards explicitly reflect the risks various compounds and elements pose to human health and the environment, and have been applied successfully to thousands of successful remediation projects over the past 19 years. This final-form rulemaking specifically provides flexibility to oil and gas operators to address small spills and releases, fully-contained releases and larger spills and releases in a flexible and straightforward manner.

Several commentators raised issues with the "alternative process" included in the proposed rulemaking, which allowed operators to meet an Act 2 standard without necessarily following the notice and review provisions under Act 2. In response to those comments, the Department deleted the alternative process from this final-form rulemaking. All cleanups will either be small enough to address through excavation or follow the process outlined in these sections and Act 2.

There were a few comments from operators who expressed concern over time constraints of report submittals that are in § 78a.66 for various portions of the remediation process. It is both reasonable and appropriate to require operators to carry out remedial actions promptly and not let contamination linger in the environment. The time frames established in this final-form rulemaking are modeled on the time frames established for corrective actions for releases from storage tanks in Chapter 245. The storage tank corrective action process was established in 1993 and has been used successfully for thousands of storage tank cleanups, both before and after the passage of Act 2 in 1995. The tank regulations were updated in 2001 to harmonize the regulations with Act 2 and the Act 2 implementing regulations in Chapter 250 (relating to administration of Land Recycling Program). These time frames are appropriate and have built-in flexibility to address the unique considerations posed by each remedial site. Finally, the Department notes that the time frames establish requirements for the steps that will lead to completion of the corrective action but do not establish a time frame by which demonstration of attainment of an Act 2 standard must be made. The Department recognizes that each site poses unique challenges and a one-size-fits-all completion date requirement is not appropriate.

§ 78a.67. Borrow pits

As a result of concerns that the requirement to restore a borrow pit within 30 days of well permit expiration was impractical, the Department revised the restoration requirements in § 78a.67 to require borrow pits to be restored 9 months after completion of drilling the final well on a well site serviced by the borrow pit instead of 9 months after completion of drilling all permitted wells on the well site or 30 calendar days after the expiration of

all existing well permits on well sites. This is in accordance with other restoration requirements that were similarly addressed in §§ 78a.59a and 78a.65. The main concern is the fact that an activity may be finished after the growing season, in fall or winter and will not be able to achieve any vegetative growth for stabilization until the next growing season. The Department believes 9 months is a reasonable time frame to ensure the operator has an opportunity to achieve this requirement.

§ 78a.68. Oil and gas gathering pipelines

This final-form rulemaking requires the use of highly visible flagging, markers or signs to be used to identify the shared boundaries of the limit of disturbance, wetlands and locations of threatened or endangered species habitat prior to land clearing. The Department received comments for and against these provisions. The Department believes it is vital to delineate special area boundaries in the field, that is, limit of disturbance, jurisdictional streams and wetlands as well as endangered species habitat otherwise unseen or not readily visible to the untrained eye, to reduce the likelihood of unintentional disturbance during clearing and grubbing or other earthmoving activities. The Department considered not requiring these sensitive areas to be clearly marked in the field during oil and gas operations. However, the Department determined that the risk of damage to sensitive areas not easily seen from large earthmoving equipment and straying beyond the permitted limit of disturbance is too great to not include this provision in this final-form rulemaking. This requirement will greatly reduce potential impacts to these resources and it not only benefits any resources that are not impacted it also benefits any permittee that may have impacted these resources inadvertently and become subject to a compliance and enforcement case by the Department. Therefore, this is the least burdensome, acceptable alternative.

This final-form rulemaking protects topsoil by requiring segregation of topsoil and subsoil during its excavation, storage and backfilling. The Department considered not requiring topsoil segregation because a number of comments were submitted suggesting this requirement should be deleted from this final-form rulemaking. However, the Department determined that the negative effects of not segregating topsoil would exceed the benefits of keeping this requirement and, therefore, this is the least burdensome yet acceptable alternative. Segregation of topsoil in all areas and phases is critical to successful restoration of pipeline right of ways. The practice of segregating topsoil favors industry by reducing the need, cost and the additional impact from importing topsoil to restore healthy vegetation after construction to establish permanent stabilization.

This final-form rulemaking requires native and imported topsoil used for pipeline right of way restoration must be of equal or greater quality of the original topsoil to ensure the land is capable of supporting the uses that existed prior to earth disturbance. Some comments were against allowing any importation of topsoil. The Department considered not requiring importation of topsoil; however, this is the least burdensome yet acceptable alternative because topsoil used for restoring the pipeline right of way is of a quality capable of supporting the preexisting uses of the land.

This final-form rulemaking requires that equipment refueling and staging areas must be out of floodways and at least 50 feet away from a body of water. The proposed setback for refueling and material staging areas from water bodies is appropriate and consistent with other

regulatory requirements in Chapter 105. Commentators stated that the Department should allow for exceptions to the 50-foot distance restriction for material staging areas. The Department agreed and, as a result, § 78a.68(f) (relating to oil and gas gathering pipelines) has been amended to allow for materials staging within the floodway or within 50 feet of a water body if first approved in writing by the Department. Due to the consideration and allowance for exceptions, with prior approved by the Department in writing, the Department believes this is the least burdensome, acceptable alternative.

This final-form rulemaking requires all buried metallic gathering pipelines to be installed and placed in accordance with 49 CFR Part 192, Subpart I or Part 195, Subpart H. Some comments received questioned the Department's statutory authority to incorporate Federal standards for pipelines into the rulemaking. Section 3218.4(a) of the 2012 Oil and Gas Act provides that "[a]ll buried metallic pipelines shall be installed and placed in operation in accordance with 49 CFR Pt. 192 Subpt. I (relating to requirements for corrosion control)." Section 78a.68(g) reflects this requirement. The incorporation of 49 CFR Part 195, Subpart H is included because that subpart also outlines standards for protecting pipelines against corrosion, specifically steel pipelines transporting hazardous liquids such as condensate from natural gas operations. The reference to 49 CFR Part 195, Subpart H is consistent with the intent of section 3218.4(a) of the 2012 Oil and Gas Act to set forth standards for the installation and placement of metallic pipelines, including related corrosion control requirements. Since it is imperative to ensure that buried metallic gathering lines do not leak and result in pollution, this is the least burdensome yet acceptable alternative, as no other known alternatives achieve the same assurance of the reduced likelihood of buried metallic gathering line pipes from leaking and it is a statutory requirement.

§ 78a.68a. Horizontal directional drilling for oil and gas pipelines

This final-form rulemaking reinforces that HDD for oil and gas pipelines is subject to Chapters 102 and 105 and that certain requirements specific to this section must be met. The Department received many comments in favor of this language. The Department also received comments stating that the language in § 78a.68a is redundant since the activity is already regulated under Chapters 102 and 105. The Department considered not including language pertaining to HDD for oil and gas pipelines in Chapter 78; however, the intent of the section is to provide clarity to existing requirements and address issues that frequently arise during HDD activities conducted by the oil and gas industry. Therefore, this is the least burdensome, acceptable alternative.

This final-form rulemaking includes a requirement for a PPC plan for HDD with a site-specific contingency plan that describes the measures to be taken to control, contain and collect any discharge of drilling fluids and minimize impacts to waters of the Commonwealth. The Department considered not including this requirement; however, due to the heightened potential for pollution to waters of the Commonwealth that HDD creates, a separate PPC plan is required for this specific activity. A separate PPC plan is not required for HDD activities provided that the PPC plan developed under § 78a.55 meets the requirements in section § 78a.68a.

HDD activities over and adjacent to bodies of water and watercourses shall be monitored for any signs of drilling

fluid discharges as required in this final-form rulemaking. Many inadvertent returns of HDD fluids express themselves hundreds of feet from the actual bore hole. Therefore, monitoring bodies of water and watercourses during HDD activities will detect impacts as soon as they occur. The Department considered not including this requirement; however, the alternative would be to not monitor for inadvertent returns which would present a significant opportunity for these instances to pollute waters of the Commonwealth without effectively seeking a solution to the problem. Therefore, this requirement is the least burdensome, acceptable alternative.

This final-form rulemaking includes a requirement to immediately notify the Department of an HDD drilling fluid discharge or loss of drilling fluid circulation. This is consistent with the reporting requirements in § 91.33 which is the least burdensome, acceptable alternative because this final-form rulemaking cannot be less stringent than this requirement.

HDD drilling fluid additives other than bentonite and water must be approved by the Department prior to use. All approved HDD fluid additives will be listed on the Department's web site to eliminate the need for preapproval prior to each use. This will ensure that HDD operators know which additives are preapproved for use without having to wait for the Department to review and approve a drilling additive. The Department considered not including this requirement; however, the Department believes this is the least burdensome, acceptable alternative because it should not be considered overly burdensome for operators to check the list provided by the Department to determine acceptable substances to be used for this activity.

§ 78a.68b. Well development pipelines for oil and gas operations

Well development pipelines that transport flowback water and other wastewaters shall be installed aboveground, as required in this final-form rulemaking. The Department received comments saying that the Department should allow all well development pipelines to be buried. The Department considered not including this requirement, but determined this is the least burdensome, acceptable alternative because buried pipelines cannot be easily inspected for leaks or damage while aboveground pipelines can be visually inspected daily when in use and if leaks or defects are observed, repairs or other effective corrective measures can be taken expeditiously, thereby reducing or avoiding the impact of an accidental pollutional event. Under the definition of "well development pipeline" in § 78a.1, if a pipeline is not used solely to move wastewater (for example, as a low-pressure gathering line) or the pipeline does not lose its utility after the well site it serviced has been restored under § 78a.65, then it does not meet the definition and does not need to meet the requirements of this section.

This final-form rulemaking specifies that well development pipelines may not be installed through existing stream culverts, storm drain pipes or under bridges that cross streams without approval by the Department under § 105.151. The Department received comments against this requirement. The Department considered not including this requirement, but determined this is the least burdensome, acceptable alternative because most culverts, storm drains and bridges that cross streams are designed and sized taking the maximum anticipated flow of water into consideration. Placing well development

pipelines in/under them displaces their capacity to carry their designed load, which could lead to localized flooding as a result.

This final-form rulemaking requires certain safety measures with well development pipelines used to transport fluids other than fresh ground water, surface water and water from water purveyors or approved sources. These pipelines shall be pressure tested prior to being placed into service and after the pipeline is moved, repaired or altered. They must have shut off valves, check valves or other methods of segmenting the pipeline placed at designated intervals that prevent the discharge of more than 1,000 barrels of fluid. They may not have joints or couplings on segments that cross waterways unless secondary containment is provided. They cannot be used to transport flammable materials. The STRONGER organization recommends that state programs should address the integrity of pipelines for transporting and managing hydraulic fracturing fluids off the well pad. The Department received comments that endorsed these provisions and comments that were against their implementation. The Department considered not including these requirements; however, the Department believes this is the least burdensome, acceptable alternative because these safety measures are necessary to protect the environment by providing mechanisms that help identify their locations, isolate sections that are compromised, minimizes direct leaks into waterways and eliminates the risk of fires. Without these requirements there would be many more opportunities for pollution to occur to waters of the Commonwealth than if they are kept in this final-form rulemaking.

This final-form rulemaking requires well development pipelines to be removed when the well site is restored. The Department received comments requesting that these pipelines should be allowed to remain to transport and reuse production water from the well site. Well development pipelines are meant to be temporary and used for the sole purpose of well development activities at a well site. Well development pipelines need to be removed when the well site get restored in accordance with § 78a.65. The Department considered not including this requirement, however, permanent pipelines used for transportation of fluids are beyond the scope of this final-form rulemaking.

This final-form rulemaking requires the operator to maintain certain records regarding well development pipelines, including their location, type of fluids transported, the approximate time of installation, pressure test results, defects and repairs. The records need to be retained for 1 year after their removal and be made available to the Department upon request. The Department received a comment that well development records should be retained by operators for 2 years after their removal. The Department believes 1 year is a sufficient amount of time for record retention due to the temporary nature of these pipelines. The Department considered the additional year of record retention but determined that there was not a significant benefit to this, therefore the requirement in the rulemaking is the least burdensome, acceptable alternative.

This final-form rulemaking requires operators to obtain Department approval for well development pipelines in service for more than 1 year. The Department believes that a well development pipeline that is in service for over 1 year becomes more than a temporary use and wants to know about its location and use.

§ 78a.69. *Water management plans*

Commentators urged the Department to include conventional operations in the requirement to develop WMPs. WMPs are a requirement of section 3211(m) of the 2012 Oil and Gas Act, which by its terms only applies to unconventional wells. This section codifies existing requirements to protect quality and quantity of water sources in the Commonwealth, including freshwater resources, from adverse impacts to the watershed considered as a whole from potentially inappropriate withdrawals of water. This final-form rulemaking mirrors most of the requirements of the Susquehanna River Basin Commission and the Delaware River Basin Commission to ensure that requirements are consistent Statewide, regardless of from which river basin an operator withdraws water. This section of this final-form rulemaking only applies to unconventional operations. The Department does not believe that the scope of water use by the conventional oil and gas industry warrants a requirement to develop WMPs as a matter of regulation. If a conventional operator will be employing high-volume slickwater hydraulic fracturing to develop a well, the Department may require a WMP as a permit condition to meet the obligations under The Clean Streams Law to protect the waters of the Commonwealth.

§ 78a.70. *Road-spreading of brine for dust control and road stabilization*

Commentators recommended the complete prohibition of spreading of brine on roads for dust control. The Department considered a complete prohibition of the road spreading of brine and determined that unconventional brines may not be spread on roads for any reason. This section was amended in this final-form rulemaking to clearly ban the use of brines and produced fluids from unconventional wells for dust control and road stabilization.

§ 78a.70a. *Pre-wetting, anti-icing and de-icing*

Commentators recommended the complete prohibition of brine being used to de-ice roads. The Department considered a complete prohibition of the road spreading of brine for pre-wetting, anti-icing and de-icing and determined that unconventional brines may not be spread on roads for any reason. This section was amended in this final-form rulemaking to clearly ban the use of brines and produced fluids from unconventional wells for pre-wetting, anti-icing and de-icing.

§ 78.121. *Production reporting*

§ 78a.121. *Production reporting*

This final-form rulemaking requires unconventional operators to report their waste production on a monthly basis within 45 days of the end of the month. The Department received significant comments on this provision from unconventional operators. Operators noted that the act of October 22, 2014 (P.L. 2853, No. 173) (Act 173) which required monthly production reporting did not include waste reporting within its scope and therefore inclusion of this requirement is inappropriate. The monthly waste reporting requirement under § 78a.121(b) (relating to production reporting) is not reliant on Act 173, therefore the legislative intent of Act 173 is not relevant to § 78a.121(b). The statutory authority for § 78a.121(b) is under provisions of the SWMA, particularly section 608(2) of the SWMA (35 P.S. § 6018.608(2)), which requires that the Department shall “[r]equire any person or municipality engaged in the storage, transportation, processing, treatment, beneficial use or disposal of any solid waste to establish and maintain such records

and make such reports and furnish such information as the department may prescribe.”

Monthly waste reporting is not due until 45 days after the end of the month in which waste was generated and managed. This should provide sufficient time for operators to receive and compile the information necessary to provide a monthly waste production report to the Department.

The Department also disagrees with the characterization of extra burden posed by more frequent reporting. While the data shall be gathered more frequently, the current data reporting requirements would still require the operator to compile and report the same data at the end of the 6-month period. Operators shall account for and report all wastes generated in the 6-month period already, the only end difference in terms of overall reporting should be that the Department would possess data segregated by month after October 8, 2016. The end totals of waste generated and facilities where that waste was managed should be exactly the same at the end of the term as it is today.

Data analyses conducted by the Department, which compared 2013 and 2014 calendar year records from facilities that receive oil and gas waste for processing or disposal and from data reported by oil and gas operators in the Department’s oil and gas electronic reporting database, revealed that there are significant discrepancies in both the quantities of waste reported by oil and gas operators and also in the way the wastes are classified. More recent analyses have indicated that oil and gas operator reporting is improving; however, the same issues still exist. The current biannual reporting requirement is not conducive to correcting reporting discrepancies because the Department does not become aware of a reporting issue until a substantial amount of time has passed from when the waste was originally sent for processing or disposal. Monthly reporting promotes quicker recognition of reporting inaccuracies that can be rectified in a more reasonable time frame.

The Department believes that the monthly time frame with reporting due 45 days after the end of the month is clearly feasible for operators. Because the current 6-month reporting requirement includes data from June in the August report and December in the February report, operators are already compiling 2 months reporting data in that 45-day window or they are out of compliance with the current regulation.

Commentators also argued that this new provision singles out the oil and gas industry with overly burdensome requirements that are not applied to other industries. The Department disagrees. The Department believes that responsible operators are aware of and track their waste generation, transportation, treatment, storage and disposal, and operating without awareness is not a BMP and is unacceptable in this Commonwealth. As a final note, the Department believes that the monthly reporting requirement strikes the appropriate balance between burden and benefit compared to other regulatory alternatives, such as keeping the current flawed 6-month reporting system or imposing a load-by-load manifest system as is currently required for hazardous wastes.

In this final-form rulemaking, § 78.121(a) is amended to delete reporting requirements for unconventional wells. The final sentence of the existing section as carried over to this final-form rulemaking, regarding electronic reporting of production data, is renumbered as subsection (b). These changes were retained because they solely affected unconventional wells.

§ 78a.122. Well record and completion report

The primary amendment to this section relates to area of review requirements. The certification by the operator that the monitoring plan required under § 78a.52a was conducted as outlined in the area of review report was moved from the well record to the well completion report. This amendment is appropriate given that monitoring occurs during hydraulic fracturing of the well as opposed to drilling, so the completion report is the proper report to contain this certification.

The Department received several comments requesting clarification of when a well is “complete,” as the completion report is due within 30 days of completion of the well, when the well is capable of production. A well is “capable of production” after “completion of the well.” Section 3203 of the 2012 Oil and Gas Act (relating to definitions) defines “completion of a well” as “[t]he date after treatment, if any, that the well is properly equipped for production of oil or gas, or, if the well is dry, the date that the well is abandoned.” The Department considers a well to be “properly equipped for production of oil or gas” under the following circumstances:

For wells not intended to have the producing interval cased or stimulated prior to production (that is, natural wells), the well is properly equipped for production when the well has been drilled to total depth.

For wells intended to have the producing interval cased, but not stimulated, prior to production, the well is properly equipped for production when the last perforation is placed.

For wells intended to be stimulated prior to production, the well is properly equipped for production upon commencement of flow back.

§ 78a.123. Logs and additional data

This section requires the submission of three types of information—standard drilling logs, specialty information and specific requests for additional data to be collected during drilling. After reviewing section 3222 of the 2012 Oil and Gas Act, the Department clarified in subsections (a) and (d) in this final-form rulemaking. The most significant change is that the Department is requiring submission of standard drilling logs for all wells in subsection (a), rather than requesting the logs for each individual well site when permits are issued.

The comments received on this section mainly concerned the confidentiality of logs submitted under subsection (a) and the time frames for submission and the perceived time frames for submission under section 3222 of the 2012 Oil and Gas Act. Section 3222(d) of the 2012 Oil and Gas Act states:

Data required under subsection (b)(5) and drill cuttings required under subsection (c) shall be retained by the well operator and filed with the department no more than three years after completion of the well. Upon request, the department shall extend the deadline up to five years from the date of completion of the well.

Subsection (a) of this final-form rulemaking requires submittal of electrical, radioactive and other standard industry logs within 90 days of completion of drilling. Those logs are referenced in section 3222(b)(4) of the 2012 Oil and Gas Act, and so are not subject to section 3222(d) of the 2012 Oil and Gas Act. This final-form rulemaking retains the 3-year and 5-year periods in section 3222(d) of the 2012 Oil and Gas Act for information in section 3222(b)(5) and (c) of the 2012 Oil and Gas Act. The

Department believes that data confidentiality is already preserved for an adequate period of time based on the existing language of 2012 Oil and Gas Act.

All comments received on the proposed rulemaking and related issues have been addressed in this final-form rulemaking.

G. Benefits, Costs and Compliance

Benefits

The residents of this Commonwealth and the regulated community will benefit from this final-form rulemaking. The process for identifying and considering the impacts to public resources will ensure that any probable harmful impacts to public resources will be avoided or mitigated while providing for the optimal development of natural gas resources. The regulations that require operators to conduct an area of review survey and appropriately monitor wells with the risk of being impacted by hydraulic fracturing activities will minimize potential impacts to waters of the Commonwealth. The containment systems and practices requirements for unconventional well sites will minimize spills and releases of regulated substances at well sites and ensure that any spills or releases are properly contained. The amendments to the reporting and remediation requirements for releases will ensure State-wide consistency for reporting and remediating spills and releases.

New planning, notification, construction, operation, testing and monitoring requirements for pits, tanks, modular aboveground storage structures, well development impoundments and pipelines will help prevent releases or spills that may otherwise result without these additional precautions. Additionally, the monitoring and fencing requirements for pits and impoundments and unconventional tank valve and access lid requirements for tanks ensure protection from unauthorized acts of third parties and damage from wildlife. Further, the requirements regarding wastewater processing at well sites will encourage the beneficial use of wastewater for drilling and hydraulic fracturing activities.

This final-form rulemaking contains several new notification requirements which will enable Department staff to effectively and efficiently coordinate inspections at critical stages of modular aboveground storage facility installation, onsite residual waste processing and HDD activities. Additionally, requiring electronic submission for well permits, notifications and predrill surveys will enhance efficiency for both the industry and the Department. As new areas of this Commonwealth are developed for natural gas, the regulations will avoid many potential health, safety and environmental issues as well as provide a consistent and efficient approach to natural gas development in this Commonwealth.

Compliance costs

Unconventional operators' costs

Assumptions

When initially proposing this final-form rulemaking, the Department estimated based on data available at the time that there will be approximately 2,600 unconventional wells permitted each year for the next 3 years.

On average, about one of every two permitted unconventional wells are drilled.

In addition, the Department estimated that there were an average of three unconventional wells per well site.

Since considerable time has passed since the proposed rulemaking was published, the Department was able

re-evaluate the rate at which unconventional wells are permitted and drilled in this Commonwealth and include data for 2013, 2014 and the first three quarters of 2015.

The Department's records also show that there are currently 3,387 unconventional well pads with at least 1 well drilled and a total of 9,486 total unconventional wells located within this Commonwealth. This equates to an average of 2.8 wells per pad. In the future, it is estimated that less well sites will be built as there could be as many as 22 wells on a pad, based on data available to the Department.

The cost analysis for this final-form rulemaking must be factored on a well site basis, not on a per well basis. Many of the processes proposed for regulation in this final-form rulemaking include activities integral to the operation of several wells and even several well pads.

<i>Year</i>	<i>Unconventional Wells Permitted</i>	<i>Unconventional Wells Drilled</i>
2010	3,364	1,599
2011	3,560	1,960
2012	2,649	1,351
2013	2,965	1,207
2014	3,182	1,327
2015*	1,919*	756*

*Data extrapolated from first 3 quarters (1,439 wells permitted, 567 wells drilled as of September 8, 2015)

Based on the data shown in the previous table which represents the most recent 5-year period, it is clear that the Department's estimate was relatively accurate. The number of wells permitted exceeded the Department's estimate but the percentage of permitted wells that have been drilled is approximately 46% since 2010 and 41% since 2013, which is lower than the Department's original estimate. The Department does not believe that the new data supports a change to its original estimate of 2,600 wells permitted per year and 1,300 wells drilled per year as a reasonable conservative estimate of the potential unconventional well drilling activity over the next 3 years.

The Department believes that the number of unconventional wells per well site will rise in time but has retained the estimate of three wells per well site for the purposes of this estimate because it is reflective of current conditions and what is expected over the next 3 years.

$$2,600 \text{ wells permitted} \times 50\% \text{ of wells drilled} = 1,300 \text{ wells drilled each year}$$

$$1,300 \text{ wells drilled each year} \div 3 \text{ wells per well site} = 434 \text{ well sites built each year}$$

Cost estimates

The Department reached out to oil and gas operators, subcontractors and industry groups to derive the cost estimates of this final-form rulemaking.

Identification of public resources (§ 78a.15)

The requirements in this section ensure that the Department meets its constitutional and statutory obligations to protect public resources.

The Department received significant public comment on these provisions from unconventional gas well operators regarding the cost of implementing the public resource screening process requirements in § 78a.15(f) and (g). Commentators disagreed with the Department's estimates

of cost for permit conditions mitigation measure to protect public resources. Commentators also argued that there will be considerable expenses related to personnel time, expert consultants needed for surveys and project delays in associated with the responses from public resource agencies. The Department acknowledges that there is some cost associated with implementing these requirements. The total cost of this provision will vary on a case-by-case basis. This cost is dependent on several variables including, the number of well sites that are within the prescribed distances or areas listed, the type and scope of operations within prescribed distances or areas, the type of public resource, the functions and uses of the public resource, specific probable harmful impacts encountered and several other variables and the available mitigation measure to avoid, mitigate or otherwise minimize impacts. Because so many significant variables exist, the cost estimate for implementation of the entire provision will vary. For that reason, the Department provides the following estimate for specific steps which allow for an estimate to be made.

The first step in the process is identification. The Department believes this process would be required for all new well sites. First an electronic review can be conducted with the Pennsylvania Conservation Explorer's online planning tool. This tool will allow operators to identify the location of the majority of public resources which require consideration under this final-form rule-making. This tool also will allow the operator to identify potential impacts to threatened and endangered species, which also must be addressed under § 78a.15(d). Since the tool may not have data to identify all the public resources listed in § 78a.15(f)(1), operators will also need to conduct a field survey of the proposed well site area to identify public resources. This field survey will likely include identification of schools and playgrounds 200 feet from the limit of disturbance of the well site. The Department estimates the cost of this field survey to be \$2,000 and the cost of the electronic survey to be \$40. Even though use of the online tool is currently required to comply with requirements protecting threatened and endangered species, the Department has included the cost in this estimate nonetheless.

$$\$2,000 \times 434 = \$868,000$$

$$\$40 \times 434 = \$17,360$$

$$\$868,000 + \$17,360 = \$885,360$$

The second step of the process is consultation with the public resource agency. This process is only applicable to well sites which are within the prescribed distances or areas listed in § 78a.15(f)(1). The Department estimates that 30% of well sites will fall within these distances or areas. Operators will be required evaluate the functions and uses of the public resource, determine any probable harmful impacts to the public resource and develop any needed mitigation measures to avoid probable harmful impact. Operators shall also notify potentially impacted public resource agencies of the impact and provide those public resource agencies the same information provided to the Department. Cost of the provision is dependent on the number of well sites impacted as well as the complexity of evaluating the functions and uses of the public resource. The Department estimates the postage will cost \$20 per notification to public resource agencies.

$$\$20 \times 434 \times 30\% = \$2,604$$

Due to the complexity of the variables in this process, the estimate for the cost of evaluating the functions and uses of the public resource and determining whether

there is a probable harmful impact will vary. In some cases, functions and uses of the public resource and any probable harmful impacts may be immediately obvious and others may be far more complex and may include multiple public resources.

The final step in the process is mitigation. The cost estimate for mitigation will vary. In some circumstances, an operator may be able to plan the location of the well site using the planning tool previously discussed to avoid public resources resulting in zero cost. Any cost associated with mitigation measures is dependent on many variables and may be situation specific in some cases. While the Department is unable to provide a specific estimate for the implementation of this entire provision, it should be noted that this cost may be substantial depending on the location of the well site.

$$\$885,360 + \$2,604 = \$887,964$$

The total cost of this provision is \$887,964 (not including consultation and mitigation).

Protection of water supplies (§ 78a.51)

This section provides the Department's interpretation of the water supply restoration and replacement in section 3218(a) of the 2012 Oil and Gas Act. This section seeks only to provide clarity to existing statutory requirements. Accordingly, the estimated new cost incurred by unconventional operators is \$0.

The total new cost of this provision is \$0.

Area of review and monitoring plans (§§ 78a.52a and 78a.73)

$$\$8,720$$

$$\$8,720 \times 1,300 \text{ wells} = \$11,336,000$$

The total cost of this provision is \$11,336,000.

The Department's 2013 Regulatory Analysis estimated the compliance cost at \$2,000 per new well. That Department estimate was made before the introduction of significant new requirements in 2015, including:

- Researching the depth of identified wells.
- Development of monitoring methods for identified wells, including visual monitoring under accompanying § 78.73 (relating to general provisions for well construction and operation).
- Gathering surface evidence concerning the condition of identified wells.
- Gathering GPS, that is, coordinate data for identified wells.
- Introduction of a provision of advanced notice to adjacent operators under accompanying § 78.73.
- The assembly of the previously listed data in an area of review report and monitoring plan and the submission of the report at least 30 days prior to the start of drilling the well at well sites where hydraulic fracturing activities are anticipated.

With the additional items, the cost of compliance is expected to exceed \$2,000 per well.

However, it is important to emphasize that industry commentators have indicated the majority of the work required as part of the area of review is already performed by operators in an effort to not only reduce potential environmental liability, but also to protect the investment associated with the drilling and stimulation of a new well, which represents millions of dollars for a typical unconventional well.

Further, it should be emphasized that the costs associated with the review of historical data will be negligible, as most unconventional companies already have subscriptions to well-location databases. EDWIN, which is one of the primary databases used for retrieving records related to oil and gas wells in this Commonwealth, costs \$500 per year for a full subscription. For a company drilling 25 wells a year this results in a cost of \$20 per well along with search and retrieval costs. Many other sources of information are free.

Most unconventional companies hire professional engineering firms to complete surveying activities. Estimates for the generation of plats, which are already required for well drilling permits, are expected to range between \$4,000 and \$5,000, with an average cost of \$4,600. These costs were gathered by speaking with companies that routinely perform this work for the unconventional industry. Assumptions include 2 days of field work and 1 day of office work to compile the data necessary for submission. It should be noted that current Commonwealth statutes only require that survey data be collected by a "responsible surveyor or engineer," and that existing law under section 3213(a.1) of the 2012 Oil and Gas Act has required operators to identify all abandoned assets discovered on their leases to the Department for many years. It is noted that one company providing information did ask that the Department consider the additional burdens being placed on the industry and expressed concerns that more oil and gas activities would be shifting to neighboring states as a result of this final-form rulemaking. The individual had asked that limits be placed on offset wells requiring identification in the area of review (active only) and indicated that landowners in drilling units have reacted in a confrontational manner with members of his staff in the past.

The Department has experience monitoring well vents in its plugging program. Costs are anticipated to remain under \$500 per day per offset well; although the number of wells requiring continuous monitoring is not expected to be very high on a case-by-case basis, as monitoring candidates must not only penetrate the zone expected to be influenced by hydraulic fracturing, but also represent a high enough risk that continuous monitoring is deemed warranted. In many cases avoidance mitigation measures, plumbing a tank to the well of concern or inspecting offset well sites periodically may be all that is necessary. For at least a fraction of the wells drilled, no offset wells will penetrate the zone of concern and monitoring costs will be negligible. This cost item is expected to range from negligible amounts to a maximum of \$7,500 per well site, with an average cost of \$3,500.

There are nominal costs associated with a certified mailing program that assumed 100 landowners are contacted in association with a well site at a cost of \$6 per mailing.

Although the Department contends that the work specified in this section of this final-form rulemaking is already being conducted by responsible unconventional operators in this Commonwealth and implementation will merely result in a marginal incremental cost for reporting, its cost analysis based on speaking with qualified professionals and its own experience contracting services in its well plugging program projects that total costs for an unconventional well operator employing standard industry practices could conceivably average around \$9,000 per well site.

For comparison, the Department recently analyzed costs associated with several unconventional well hydro-

lic fracturing communication incidents documented in this Commonwealth. The circumstances surrounding these incidents varied: two involved communications between a well that was being stimulated and a nearby well being drilled; another involved communication between two stimulated wells that had not been flowed back and a well that was being hydraulically fractured on the same pad; and the last involved communication with a previously unknown and inadequately plugged conventional well. Costs associated with unconventional wells tend to be derived from a more complicated set of variables that not only must factor in the equipment being used and subsequently placed on standby at the time of the incident (for example, costs range from \$10,000 to \$50,000 per day); but also lost revenues in association with delayed production and the need to meet gas-market commitments by established deadlines that may prompt reconfiguring existing well network flow-to-pipeline parameters or purchasing gas on the open market, or both. These costs are potentially further compounded by any environmental issues that shall be addressed (for example, water well sampling/monitoring and analytical costs and consultant costs for data analysis and interpretation), logging and downhole camera costs to inform any well work that shall be completed, plugging costs of any unconventional wells affected beyond repair and any improperly plugged legacy wells, material costs (for example, loss of drilling muds that are normally rented) and accelerated expenditures to prepare a new site. Cost estimates for the first two incidents ranged from \$90,000 to \$800,000. Total costs for the second scenario, which involved plugging two drilled unconventional wells that had not been brought back into production, are estimated at \$13 million to \$16 million. Total costs for the third scenario were in excess of \$1 million. The Department acknowledges that in certain cases, even with the implementation of this final-form rulemaking and the application of best practices, that some percentage of communication incidents will still take place. However, it adds that this regulatory concept is being addressed and acknowledged by a number of other regulatory programs, the STRONGER organization and the American Petroleum Institute, a globally recognized industry trade organization. It is also significant to note that a single severe hydraulic fracturing communication incident is capable of exceeding the estimated annual cost of implementation for an entire unconventional industry.

Site-specific PPC plan (§ 78a.55)

This final-form rulemaking requires all unconventional operators to develop and implement a site-specific PPC plan under § 78a.55. The Department received significant public comment from operators on this section. Commentators expressed concerns about § 78a.55(a) which simply reiterates the requirements already existing in §§ 91.34 and 102.5(l). Because § 78a.55(a) does not establish any new requirements, the Department does not believe that this subsection presents any new burden on operators and no cost was attributed with these provisions.

The Department initially estimated that the new cost of this requirement would be between \$86,800 and \$130,200. Upon further evaluation, the Department revised this estimate. The requirement for operators to develop a control and disposal plan or PPC plan has been in existence under § 78.55 since 1989 when Chapter 78 was first adopted. A plan that does not address the specific needs of a site could not and should not be considered to meet the requirements of § 78.55. Therefore, for operators to ensure that they were in compliance with the planning requirements in § 78.55, they must have been

evaluating their PPC or control and disposal plans against site-specific conditions since 1989. In addition, it is not the intent of this final-form rulemaking nor is it required under this final-form rulemaking that each PPC plan developed for a different well site must be unique. Therefore, the Department does not believe its initial estimates are accurate. Instead, the Department estimates the new cost associated with this requirement to be negligible because operators have been required to develop these plans since 1989.

It is not the intent of this final-form rulemaking to ensure that all PPC plans are revised annually. There are no specific review and update time frames included in this final-form rulemaking. This final-form rulemaking requires revisions to the plan in the event that practices change. Therefore, if conditions at the site do not change, there will be no need to make revisions to the PPC plan. In addition, operators have been required to revise their plans under these same conditions since Chapter 78 was initially adopted in 1989. Therefore, there is no new cost attributed to this provision.

Finally, this final-form rulemaking does not include a requirement that every single site where activities including the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants shall have the PPC plan posted onsite at all times. This final-form rulemaking does not include this requirement or anything resembling this requirement. In fact, this final-form rulemaking does not require the PPC plan to be maintained on the site at all. The Department believes that it is prudent for operators to maintain the PPC plan on the site when the site is active, including drilling, alteration, plugging or other activities when there is an increased risk of a spill, release or other incident, but it is not required by § 78a.55. Therefore, there is no new cost attributed to this requirement.

The total new cost of this provision is \$0 (negligible).

Providing copies of the PPC plan to the Fish and Boat Commission and the landowner (§ 78a.55(f))

This final-form rulemaking includes a requirement for operators to provide copies of the site-specific PPC plan to the Fish and Boat Commission and the landowner upon request. The cost associated with this requirement depends on the number of plans that are requested. If no plans are requested, there is no cost associated with this requirement. If the landowner and the Fish and Boat Commission request the plan for every well site, the Department estimates the cost to be \$21,700.

$$434 \times \$25 \times 2 = \$21,700.$$

The total new annual cost of this provision is estimated to be \$21,700.

Banning use of pits (§ 78a.56)

This final-form rulemaking disallows the use of pits for temporary storage of waste at unconventional well sites. The Department does not believe that this provision will result in any significant cost because pits are rarely used for this purpose at unconventional well sites.

This final-form rulemaking requires pits at unconventional well sites to be restored by April 8, 2017. The Department does not anticipate that this section will result in any significant new cost because pits are rarely used at unconventional well sites and because pits regulated under § 78.56 are already required to be restored within 9 months of completion of drilling of the well serviced by the site.

The estimated new cost of this provision is \$0.

Fencing around unconventional well site pits (§ 78a.56(a)(5))

When initially proposed this paragraph required unconventional operators to install fencing around pits on well sites. This final-form rulemaking does not allow unconventional operators to utilize waste pits on their well site. Since this provision does not exist, there is not associated cost.

The total cost of this provision is \$0.

Determination of seasonal high groundwater table for pits and labor to inspect and test the integrity of the liner (§§ 78a.56(a) and 78a.62)

When initially proposed these sections required unconventional operators to make a determination of the depth to seasonal high groundwater table and inspect liners for pits on well sites. This final-form rulemaking does not allow unconventional operators to utilize waste pits on their well site. Since this provision does not exist, there is not associated cost.

The total cost of this provision is \$0.

Tank valves and access lids equipped to prevent unauthorized access by third parties (§§ 78a.56(a)(7) and 78a.57(h))

If the well site has 24-hour security presence, the operator satisfies the requirements of these sections. This calculation assumes that all well sites will not have 24-hour security. This should be a one-time expense as the protective measures will be affixed to the tanks. The Department estimates \$7,000 for each well site.

$$\$7,000 \times 434 = \$3,038,000$$

The total cost of this provision is \$3,038,000.

Signage for tanks and other approved storage structures (§ 78a.56(a)(8))

Unconventional operators will be required to display a sign on the storage structure identifying the contents and if any warnings exist, such as corrosive or flammable.

The cost of this regulatory requirement depends on the number of tanks/storage structures and the types of signage used. The Department assumes that the cost can be in the range of \$250—\$2,000 for each well site.

$$\$250 \times 434 = \$108,500$$

$$\$2,000 \times 434 = \$868,000$$

The total cost of this provision is between \$108,500 and \$868,000.

Vapor controls for condensate tanks (§ 78a.56(a)(10))

Vapors must be controlled at all condensate tanks. Based on Department inspection experience, this calculation assumes that only 40% of well sites will have condensate tanks. The Department estimates \$12,500 for each well site.

$$\$12,500 \times (434 \times 40\%) = \$2,170,000$$

The total cost of this provision is \$2,170,000.

Secondary containment for all aboveground structures holding brine or other fluids (§ 78a.57(c))

The cost of this subsection depends on the number of aboveground structures on each well site.

The Department assumes that the cost can be in the range of \$5,000—\$10,000 for each well site.

\$5,000 × 434 = \$2,170,000

\$10,000 × 434 = \$4,340,000

The total cost of this provision is between \$2,170,000 and \$4,340,000.

Identification of existing underground/partially buried storage tanks and registration of new underground/partially buried storage tanks (§ 78a.57(e))

When initially proposed, this subsection prohibited the use of underground or partially buried storage tanks for storing brine and operators would have 3 years to remove all existing underground or partially buried tanks. The Department's initial cost estimate did not attribute a cost to this subsection because the cost was dependent on the number of buried tanks across this Commonwealth and the Department was unable to estimate the number of buried tanks at that time. As a result of public comment, the Department amended this final-form rulemaking to allow the use of buried tanks by both conventional and unconventional well site operators and does not require removal of existing buried tanks. The Department continues to believe that underground storage tanks warrant extra scrutiny because they are not as easily inspected and can provide a more direct conduit for contamination into groundwater and therefore has included provisions in this final-form rulemaking to require the location of all existing and any new underground storage tanks at well sites to be reported to the Department. Therefore, the original estimate of \$20,000 is retained. The Department does not believe that there will be any significant new

cost associated with notifying the Department of newly installed underground or partially buried tanks.

The total cost of this provision is estimated to be \$20,000.

Corrosion protection for permanent aboveground and underground tanks (§ 78a.57(f) and (g))

Section 78a.57(f) and (g) implements section 3218.4(b) of the 2012 Oil and Gas Act which establishes that permanent aboveground and underground tanks must comply with the applicable corrosion control requirements in the Department's storage tank regulations.

It is common knowledge that steel structures, including storage tanks, corrode or rust and fail when left unprotected and exposed to the elements. It is also common knowledge that brine or salt water which is commonly stored in tanks at conventional well sites increases the rate of corrosion of steel. Given these facts and considering that the estimated cost for replacement tanks is significantly higher than the estimated cost for providing corrosion protection for those same tanks (see the following table; the estimated costs for providing corrosion protection is less than half the cost of a new tank), the Department believes that it would behoove gas operators to provide corrosion protection for their tanks because it can extend the useful life of the tank significantly at a fraction of the cost of replacing the tank. In fact, this provision may represent a cost savings to operators that had previously not been maintaining their tanks appropriately.

Size (bbl)	Current Cost	Cathodic Protection	Corrosion Protection	Ratio of Cost of Corrosion Protection to Replacement
25 bbl	\$1,800	\$350	\$450	0.44
50 bbl	\$2,200	\$350	\$650	0.45
100 bbl	\$3,451	\$350	\$1,200	0.45
140 bbl	\$5,144	\$350	\$1,300	0.32
210 bbl	\$6,083	\$350	\$1,600	0.47

Finally, this requirement is a statutory requirement under section 3218.4(b) of the 2012 Oil and Gas Act. As previously noted, § 78a.57(f) and (g) simply implements this requirement. The Department has also explicitly deleted the requirement to use Department certified inspectors to conduct inspections of interior linings or coatings which will alleviate some burden on oil and gas operators. Operators may choose to use nonmetallic tanks which can often be less expensive than steel equivalent and do not require any additional cost to ensure protection from corrosion.

Since this section implements existing statutory requirements, no cost is assigned to this provision.

The estimated new cost of this provision is \$0.

Monthly maintenance inspection (§ 78a.57(i))

Section 78a.57 imposes a new requirement for operators to conduct periodic inspections of tanks used to control and store production fluids on a well site and document each inspection. The monthly maintenance inspection is intended to be a visual check of the tank and containment area to ensure that the tank and containment structures are in good working condition and that ancillary and safety equipment are in place and in good working condition. The Department estimates that on average

inspection of each tank, including filling out the inspection form, will take 15 minutes. When initially proposed this provision required use of forms provided by the Department but in response to comments the provision was revised to allow operator generated forms. The Department will provide a form for use by operators that prefer to use the Department's form or do not have their own inspection documentation.

The Department estimates that the unconventional industry utilizes approximately 30,000 tanks. With a labor rate of \$30/hour the cost to perform monthly maintenance inspections is \$2.7 million per year or \$90 per tank per year.

Based on comments received, the Department believes that the majority of unconventional well operators are already engaged in some form of periodic tank inspection. With the flexibility of being able to use operator generated forms, the Department does not believe that this provision represents a significant burden on unconventional operators.

The Department believes that periodic inspections are appropriate common sense accident prevention steps that every storage tank operator should follow. In addition, it is almost always less costly to prevent an accident than to remediate the harm that is caused when an accident

occurs. Remediation of a single spill could cost more the total annual cost to inspect all storage tanks utilized unconventional oil and gas well operators.

The estimated new annual cost of this provision is \$2.7 million.

Radiation protection action plan (§ 78a.58(d))

The Department added § 78a.58(d) to this final-form rulemaking to require an operator processing fluids onsite to develop a radiation protection action plan which specifies procedures for monitoring and responding to radioactive material produced by the treatment process. This section also requires procedures for training, notification, recordkeeping and reporting to be implemented. This section does not require review or approval by the Department prior to implementation of the plan. In addition, the Department does not believe that a new or unique plan shall be developed for each individual well site where processing occurs. Many operators will probably find that a single plan developed under this provision is applicable to processing operations over large geographic areas.

The Department estimates that processing which would require this plan occurs on approximately 75% of well sites or 326 sites per year.

$$434 \text{ sites} \times 75\% = 326 \text{ sites}$$

The Department also estimates that plans developed under this provision will be applicable to 50% of an operator's sites on average or 163 sites per year.

$$326 \text{ sites} \times 50\% = 163 \text{ sites}$$

Some operators may only need a single plan and others may need several, depending on their operations.

The Department estimates that development of a radiation protection action plan under this section will cost between \$2,000 and \$5,000 per plan for initial development. In addition, to implement the plan, operators who develop a plan will need to purchase a dose rate meter. The Department estimates the cost of the dose rate meter to be \$1,000—\$2,000. Finally, operators will be required to provide training on the plan to staff. This training is typically conducted by the plan development consultant but may be conducted by others. The Department estimates that annual training of staff will cost \$1,000—\$2,000 per plan.

Cost of development

$$163 \times \$2,000 = \$326,000$$

$$163 \times \$5,000 = \$815,000$$

Cost of training

$$163 \times \$1,000 = \$163,000$$

$$163 \times \$2,000 = \$326,000$$

A new meter will not be required for each plan. Operators may be able to use the same meter for multiple sites throughout the year depending on the location of the site. The Department estimate that industry will need to purchase 85 dose rate meters to comply with this requirement.

Cost of meters

$$85 \times \$1,000 = \$85,000$$

$$85 \times \$2,000 = \$170,000$$

The total annual cost is equal to the cost of development plus the cost of training. The total initial cost is equal to the cost of meters.

$$\$326,000 + \$163,000 = \$489,000$$

$$\$815,000 + \$326,000 = \$1,141,000$$

Therefore, the estimated annual cost of this provision is between \$489,000 and \$1,141,000 and the estimated initial cost is estimated to be between \$85,000 and \$170,000.

Well development impoundment construction standards (§§ 78a.59a and 78a.59b)

In this final-form rulemaking, §§ 78a.59a and 78a.59b impose construction and operation standards for well development impoundments including embankment construction standards, the need for surrounding well development impoundments with a fence and providing an impermeable plastic liner. The Department received comments from unconventional operators indicating that the cost of all new requirements applicable to well development impoundments, excluding fencing around the impoundment, is \$250,000 to \$500,000 per impoundment and a total cost of \$25 million based on the Department's estimate of 100 existing freshwater impoundments. The commentator did not provide a breakdown of how the projected cost was derived.

The Department disagrees with the commentator's cost estimate. First, many of the new requirements are only applicable to new impoundments. Operators shall only certify that existing impoundments meet the requirement for having a synthetic liner, being surrounded by a fence and properly storing MIW. This final-form rulemaking does not require any certification of structural integrity or a groundwater depth determination for existing impoundments so those costs should not be considered for existing impoundments. The requirement to ensure that MIW is properly stored exists regardless of the well development requirements in Chapter 78a so those costs should not be considered for existing impoundments.

The Department understands that the majority of existing well development impoundments already have an impermeable synthetic liner. In addition, it is important to note that the well development impoundment requirements do not apply to water sources such as lakes or ponds, so to the extent that commentators included these types of facilities in their cost estimates, they may have overestimated. The Department estimates that 90% of the existing well development impoundments have a synthetic liner installed so only a small number of well development impoundments will require addition of a synthetic liner under this final-form rulemaking. The Department made the initial estimate of 100 existing well development impoundments in 2013 which would equate to an average of 20 well development impoundments constructed per year. Based on this rate of development, the number of existing well development impoundments is estimated to be 140 since 2 years have passed since the initial estimation.

The Department estimates that on average, a well development impoundment will require 250,000 square feet of synthetic liner to comply with this final-form rulemaking. The estimated cost of installed 30 mil HDPE liner to meet this requirement is 40¢/square foot resulting in a total cost of \$1.26 million.

$$250,000 \times 0.40 \times 90\% \times 140 = \$1,260,000 \text{ for liner installation}$$

The cost of the fencing is dependent upon the size of the impoundment and the type of fencing used. Based on 140 well development impoundments throughout this Commonwealth and assuming that none of them cur-

rently have fencing the Department estimates that the total cost of this provision is between \$980,000 and \$7 million.

$$\$7,000 \times 140 = \$980,000$$

$$\$50,000 \times 140 = \$7,000,000$$

This final-form rulemaking also requires operators to register the location of well development impoundments with the Department. Assuming a total of 140 existing well development impoundments, the Department estimates a total cost of \$13,000.

$$\$1,260,000 + \$980,000 + \$13,000 = \$2,253,000$$

$$\$1,260,000 + \$7,000,000 + \$13,000 = \$8,273,000$$

The initial cost of this provision is estimated to be between \$2.253 million and \$8.273 million.

For new impoundments, the total cost is dependent upon the number of new impoundments constructed. Based on past trends, the Department estimates that 20 new well development impoundments will be constructed each year. The standards under § 78a.59b provide reasonable requirements to ensure that well development impoundments are structurally sound and protective of public health and safety and the environment. The standard of structurally sound and protective of public health and safety and the environment is a standard that all well development impoundments should meet. To the extent that operators are currently engaged in the practice of constructing and operating impoundments that are not structurally sound and protective of public health and safety and the environment, the Department asserts that they are not only operating irresponsibly but also out of compliance with Department regulations. The Department also notes that § 78a.59a(b) allows an owner or operator to deviate from the requirements in this section provided that the alternate practices provides equivalent or superior protection to the requirements in § 78a.59a. Therefore, these sections should not create any significant new costs to responsible operators.

The Department estimates the cost of determining the depth of the seasonal high groundwater table to be \$3,500 per impoundment.

The Department estimates a total cost of \$100,000 for installing liners in each impoundment based on the cost of 40¢/square foot for installed 30 mil HDPE liner and 250,000 square feet of liner per impoundment on average.

The Department estimates the cost of installing fencing to be \$7,000—\$50,000 per impoundment depending on the size of the impoundment and the type of fencing used.

This results in a total estimated cost of \$110,500 and \$153,500 per impoundment and a total annual cost of \$2.21 million to \$3.07 million.

$$(\$3,500 + \$100,000 + \$7,000) \times 20 = \$2,210,000$$

$$(\$3,500 + \$100,000 + \$50,000) \times 20 = \$3,070,000$$

Therefore, the total estimated annual cost of this provision is between \$2.21 million and \$3.07 million.

Centralized impoundments (§ 78a.59c)

This final-form rulemaking requires unconventional operators to either close or obtain a permit from the Department's waste management program for existing centralized impoundments. The Department did not include a cost estimate for this provision in the proposed rulemaking because it allowed for continued use of these facilities under Chapters 78 and 78a. The cost of this provision is dependent on the number of facilities im-

pacted and how operators decide to comply. The Department received significant comment on this section from unconventional operators. Commentators estimate that the cost to permit a new centralized impoundment under Chapter 289 may increase by \$120,000 to \$230,000 based on site conditions. Commentators also noted that if an operator chooses to close an existing permitted centralized impoundment due to this final-form rulemaking, an owner may realize a loss of \$1.5 million to \$2.5 million of investment plus the immediate additional costs to restore the site. If a centralized impoundment permit has been submitted to the Department under the current regulations and is pending review, an applicant would realize a loss of \$150,000 to \$250,000 plus costs associated with the time to prepare the application as a result of this revision.

The Department does not agree with these cost estimates. First, the costs associated with restoration of existing centralized impoundments should not be considered because restoration of the centralized impoundment has always been required. Second, the standard for construction of a centralized impoundment under Chapter 78 and the Department's existing centralized impoundment program are substantially similar to those required by the residual waste regulations. The Department believes that the majority of costs associated with development of pending applications under the existing centralized impoundment program are applicable to the costs associated with the residual waste permit and therefore no cost should be associated with pending applications.

The cost associated with this provision is dependent on the number of impoundments impacted. There are a total of 26 centralized impoundments operated by 6 unconventional operators in this Commonwealth. The Department believes that operators will choose to restore a number of the existing impoundments rather than obtain a permit from the Department's waste management program because older centralized impoundments were not constructed to standards as closely matched to the waste requirements as newer impoundments and those older impoundments also may be approaching the end of their useful lives. The Department presumes that the replacement cost for each centralized impoundment is between \$1.5 million and \$2.5 million. To the extent that operators choose to restore and replace all of the existing centralized impoundments, the estimated cost of this provision is between \$33 million and \$55 million.

$$20 \times \$1,500,000 = \$30,000,000$$

$$20 \times \$2,500,000 = \$50,000,000$$

The initial cost of this provision is estimated to be between \$39 million and \$65 million.

Based on past trends, the Department estimates that four centralized impoundments will be constructed per year. If the cost to permit and construct impoundments under Chapter 289 is \$120,000 to \$230,000 per impoundment, the estimated annual cost is between \$480,000 and \$920,000.

Therefore, the total estimated annual cost of this provision is estimated to be between \$480,000 and \$920,000.

Onsite disposal (§§ 78a.62 and 78a.63)

This final-form rulemaking requires unconventional operators to obtain a permit from the Department prior to disposing contaminated drill cuttings or drill cuttings from below the surface casing seat either in a pit or by land application on the well site. This revision removes

the permit-by-rule structure for waste disposal on unconventional well sites. The Department does not expect this provision to add any significant cost for unconventional operations. It has become less and less common for unconventional operators to utilize onsite disposal of contaminated drill cuttings and drill cuttings from below the surface casing seat. In fact, there have been many instances where unconventional operators have exhumed previously encapsulated cuttings due to liability concerns. In addition, the practice of drilling many wells on a single site is generally incompatible with onsite disposal simply due to the volume of waste materials generated and the limited space available. An example of this is the Big Sky pad in Greene County where a total of 22 wells have been drilled as of May 2015.

The total cost of this provision will be dependent on the number of well sites where operators seek permits for onsite disposal. The Department's review of waste disposal data for unconventional wells shows that for the reporting periods from January—June 2014, July—December 2014 and January—June 2015 cuttings from five wells have been disposed through onsite encapsulation and no cuttings have been disposed through land application. During that same time period, 1,746 unconventional wells were drilled so less than 0.3% of wells utilized onsite disposal. In addition, the five wells which utilized onsite disposal were vertical wells that generated 100—120 tons of cuttings so the total mass of cuttings disposed during that time was less than 600 tons while the total mass of drill cuttings generated during that time was over 2.1 million so less than 0.03% of the total mass of cuttings generated by unconventional wells was disposed through onsite disposal. Since these methods are so rarely used, the Department does not believe that this provision will impose any significant cost to the unconventional industry.

The total new cost of this provision is \$0.

Alternative waste management (§ 78a.63a)

This section codifies the existing practice of requiring approval for alternative waste management practices. There is no cost associated with this section.

The total new cost of this provision is \$0.

Secondary containment (§ 78a.64a)

This final-form rulemaking codifies the statutory requirement of the 2012 Oil and Gas Act for secondary containment.

This cost estimate is conservative and assumes that an operator will use brand new secondary containment at every well site. According to industry secondary containment specialists, many of the secondary containment liners will be reused at multiple well sites. The Department reached out to secondary containment vendors upon finalization of the draft final-form regulations to ensure that cost estimates received in 2013 remained accurate. Vendors indicated that since the initial estimate there has been nearly a 50% decrease in the cost of materials typically used for containment as well as the cost for installation of secondary containment. The Department has retained the initial cost estimate to ensure to be conservative and because material costs fluctuate based on commodity markets.

The Department estimates that the cost of providing secondary containment on an unconventional well site under § 78a.64a to be \$140,000.

$\$140,000 \times 434 = \$60,760,000$

The total annual cost of this provision is \$60.76 million.

Section 78a.64a requires materials used for secondary containment to have a coefficient of permeability not greater than 1×10^{-10} cm/s. This requirement effectively eliminates use of natural materials such as clay soils for secondary containment on well sites. The Department does not believe that this standard adds any significant cost over a standard that may allow for the use of natural materials. First, natural materials that are sufficiently impermeable to be effective secondary containment are not generally readily available in this Commonwealth in the areas where unconventional well development occurs. This means that materials would have to be sourced from other areas and hauled to the well site. Clay soils shall also be installed in a much thicker layer than synthetic liners to provide sufficient protection which means more material shall be hauled to the site adding significant hauling costs over a synthetic material. Second, the cost of installation of natural materials as a secondary containment is also significantly more costly and time consuming than synthetic materials.

When initially proposed, this provision required that the synthetic materials used for secondary containment must demonstrate compatibility with the contained fluid. Commentators pointed out that ASTM D5747 is a test for landfill liners and pits where the liner is submerged in diluted chemicals for extended period of time and the test costs around \$5,000 to run on each chemical type found at a site. Operators suggest ASTM D543 as an alternate test. By considering the comments, this final-form rulemaking has been changed and the Department allows for the use of test methods if approved by the Department.

Since this is an existing statutory requirement that unconventional operators must already comply with, the total new cost of this provision is \$0.

The total new cost of this provision is \$0.

Site restoration (§ 78a.65)

This section largely restates the restoration requirements in section 3216 of the 2012 Oil and Gas Act and incorporates the Department's interpretation of these requirements and the Chapter 102 requirements as outlined in the *Policy for Erosion and Sediment Control and Stormwater Management for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 800-2100-008, which was finalized on December 29, 2012. The revisions to § 78a.65 in the ANFR were also intended to address comments on this section that indicated continuing confusion regarding what constitutes restoration as the term is used Chapters 78a and 102, and what the associated requirements are. The changes to this section in the ANFR clarify this question and in particular distinguish between areas not restored and other areas. "Areas not restored" do not fall within the provisions in § 102.8(n) and therefore must meet the requirements, among others, of § 102.8(g). Areas not restored include areas where there are permanent structures or impervious surfaces.

The Department received significant comment on this provision from unconventional operators. Commentators argued that the Department failed to include any estimate for the cost associated with the new site restoration requirements. Commentators did not agree with the Department's position regarding cost savings due to the added provision of 2-year extension of the restoration

period. Unconventional operators estimated that the cost of well site restoration will be approximately \$200,000 to \$300,000 per pad, not \$50,000 as Department estimated. Therefore, rather than a \$21.7 million savings, the restoration requirements are a cost of \$130 million.

The Department does not agree with these cost estimates. The restoration requirements in this section are not new and do not impose a new cost on the regulated community as previously explained. In addition, the Department disagrees with commentators' assertions that the extension requirement is merely a postponement of the cost. This section mirrors the requirements in section 3216(g) of the 2012 Oil and Gas Act that allow operators to request to extend the restoration period for up to 2 years so that an operator does not have to restore the site and then disturb it again if it plans to drill additional wells on the same well pad. The cost savings associated with the restoration extension are derived from avoiding the cost of restoring the site within 9 months of completion of drilling and later having to reconstruct the site and restore it again. The Department revised its estimate that this provision will result in \$21.7 million in cost savings. Since the 2-year extension is provided by statute, operators may be granted an extension regardless of the status of § 78a.65, the revisions to this section do not represent a cost savings for operators.

This section is intended to provide clarity for implementing existing requirements from the 2012 Oil and Gas Act and Chapter 102. To the extent that an operator would incur the costs previously listed, they would incur those costs regardless of the status of § 78a.65 because they are costs associated with complying with the 2012 Oil and Gas Act and Chapter 102.

The total new cost of this provision is \$0.

Reporting and remediation of spills and releases (§ 78a.66)

Section 78a.66 establishes a reporting and remediation process for spills and releases that occur at well sites including a requirement to follow the procedures established under Act 2. Prior to this final-form rulemaking, the Department addressed spills through the policy "Addressing Spills and Releases at Oil & Gas Well Sites or Access Roads" which included allowances for use of an alternative process. This final-form rulemaking eliminates use of the alternative process. The Department received significant public comment on this section from oil and gas operators indicating that the Act 2 process increases the cost of remediation by three to four times the alternative process. Commentators also noted an individual cast in which they asserted that the remediation should have only cost \$10,000 but was expected to cost \$250,000 due to the Act 2 process. Commentators did not provide any specific details to fully explain the estimated costs. Commentators also argued that the timelines established for completing various steps of a spill remediation are inappropriate and overly burdensome for the oil and gas industry.

The Department does not agree with the cost estimates. The cleanup process established under § 78a.66 includes the steps necessary to ensure that spills are appropriately remediated. To the extent that operators are remediating spills, they should generally be conducting the steps outlined by the Act 2 process. To the extent that operators are not conducting the steps outlined by the Act 2 process, the Department asserts that they may not be properly remediating spills. Therefore, since operators should already be conducting the required steps, the only

new requirement under this final-form rulemaking is that operators shall follow the Act 2 process in accordance with the required timelines. Since operators are required to remediate spills, the Department does not believe that the timelines established under this section represent a new cost; as commentators have noted, postponement of a cost is not an avoidance of the cost. The Department does not believe that a requirement to follow the Act 2 process represents any significant burden on the oil and gas industry.

The total cost of this provision is dependent upon the total number of spills or releases that shall be reported and remediated. It is not possible for the Department to predict the number of spills or releases that will occur at well sites. Therefore, the Department is unable to provide a specific cost estimate for this provision; however, the Department does not believe that this provision represents any significant new cost to the oil and gas industry.

Borrow pits (§ 78a.67)

Section 78a.67(b) requires the registration of the location of existing borrow pits by December 7, 2016, and registration of new borrow pits before there are built. This will be done electronically through the Department's web site. There were a few comments from operators that this would be burdensome on industry. The Department does not believe that the requirement to register the location of existing borrow pits with the Department represents a significant burden on the industry and has not assigned a cost to this requirement.

Section 78a.67(a) requires an oil and gas operator who owns or controls a borrow pit that does not require a permit under the NSMCRA under the exemption in section 3273.1(b) of the 2012 Oil and Gas Act to operate, maintain and reclaim the borrow pit in accordance with the performance standards in Chapter 77, Subchapter I and in accordance with Chapter 102.

The exemption in section 3273.1(b) of the 2012 Oil and Gas Act was taken verbatim from the 1984 Oil and Gas Act. This section seeks to provide clarity for implementation of those requirements; therefore, the Department has not assigned a new cost to this requirement.

The total estimated cost of these provisions is \$0.

Gathering lines (§ 78a.68(a)–(f))

This section establishes common sense environmental controls for construction of oil and gas gathering lines. These requirements are intended to help ensure that operators maintain compliance with The Clean Streams Law and Chapters 102 and 105 when constructing gathering lines. The Department believes that most operators already comply with the bulk of these requirements and will not have to make any significant changes to their operations. The cost of these provisions is dependent on the number of linear miles of pipeline installed and the terrain in which the pipeline is installed. The Department does not have sufficient data to produce an estimated cost of these provisions but since most operators should already be in compliance with the bulk of these common sense environmental controls, the Department does not believe that this section will result in any significant burden to the oil and gas industry.

Corrosion control for gathering lines (§ 78a.68(g))

This final-form rulemaking requires that all buried metallic gathering pipelines shall be installed and placed in operation in accordance with 49 CFR Part 192, Subpart I or Part 195, Subpart H. Some comments received questioned the Department's statutory authority to incor-

porate Federal standards for pipelines into the rule-making. Section 3218.4(a) of the 2012 Oil and Gas Act provides that “[a]ll buried metallic pipelines shall be installed and placed in operation in accordance with 49 CFR Pt. 192 Subpt. I (relating to requirements for corrosion control).” Section 78a.68(g) reflects this requirement. The incorporation of 49 CFR Part 195, Subpart H is included because it also outlines standards for protecting pipelines against corrosion, specifically steel pipelines transporting hazardous liquids such as condensate from natural gas operations. The reference to 49 CFR Part 195, Subpart H is consistent with the intent of section 3218.4(a) of the 2012 Oil and Gas Act to set forth standards for the installation and placement of metallic pipelines, including related corrosion control requirements. Since this provision is a statutory requirement, the Department has not assigned a new cost.

The total new cost of this provision is \$0.

HDD (§ 78a.68a)

This section establishes common sense environmental controls for conducting HDD. These requirements are intended to help ensure that operators maintain compliance with The Clean Streams Law and Chapters 102 and 105 when conducting HDD. The Department believes that most operators already comply with the bulk of these requirements and will not have to make any significant changes to their operations. The cost of these provisions is dependent on the number of horizontal directional bores completed and the terrain in which the bores are completed. The Department does not have sufficient data to produce an estimated cost of these provisions but since most operators should already be in compliance with the bulk of these common sense environmental controls, the Department does not believe that this section will result in any significant burden to the oil and gas industry.

Well development pipelines for oil and gas operations (§ 78a.68b)

Subsections (a) and (d)—(n) establish common sense environmental controls for constructing and operating well development pipelines. These requirements are intended to help ensure that operators maintain compliance with The Clean Streams Law and Chapters 102 and 105 when constructing and operating well development pipelines. The Department believes that most operators already comply with the bulk of these requirements and will not have to make any significant changes to their operations. The cost of these provisions is dependent on the number of well development pipelines constructed and utilized and the terrain in which the well development pipelines are constructed. The Department does not have sufficient data to produce an estimated cost of these provisions but since most operators should already be in compliance with the bulk of these common sense environmental controls, the Department does not believe that this section will result in any significant burden to the oil and gas industry.

Prohibition of buried well development pipeline (§ 78a.68b(b) and (c))

One specific requirement in this section is the requirement that well development pipelines that carry fluid other than fresh ground water, surface water, water from water purveyors or water from Department approved sources shall be installed aboveground except when crossing pathways, roadways, railways, water courses or water bodies. This section also limits the use well development pipelines to a time period of 1 year. Operators expressed significant concerns about these provisions because many

operators maintain a network of buried pipelines that fit the definition of well development pipelines. Commentators did not provide any cost estimates to the Department for this provision.

The cost of these provisions is dependent on the number of pipelines that are impacted. The Department does not have sufficient data to make a detailed cost estimate but notes that the costs could be substantial.

WMPs (§ 78a.69)

This final-form rulemaking implements requirements in section 3211(m) of the 2012 Oil and Gas Act which requires anyone who withdraws or uses water from water sources within this Commonwealth for drilling or hydraulic fracture stimulation of any natural gas well completed in an unconventional gas formation to do so in accordance with an approved WMP.

Since this section implements existing statutory requirements, it does not represent a new cost to the oil and gas industry.

The total new cost of this provision is \$0.

Monthly waste reporting requirements (§ 78a.121)

This final-form rulemaking includes a requirement for unconventional operators to report waste production to the Department on a monthly basis. This is different from the existing requirement to report once every 6 months. The Department received significant comment on this requirement from operators indicating that it is costly and overly burdensome. Commentators estimated that waste reporting will take 20–30 hours on average regardless of the length of the reporting period. The new cost associated with this provision is the difference in the current cost to report and the new cost to report. The Department assumes a labor rate of \$30/hour to do the reporting.

The current cost is between \$1,200 and \$1,800 per year for each operator.

$$20 \text{ hours} \times \$30/\text{hour} \times 2 \text{ reports/year} = \$1,200$$

$$30 \text{ hours} \times \$30/\text{hour} \times 2 \text{ reports/year} = \$1,800$$

The new cost is between \$7,200 and \$10,800 per year for each operator.

$$20 \text{ hours} \times \$30/\text{hour} \times 12 \text{ reports/year} = \$7,200$$

$$30 \text{ hours} \times \$30/\text{hour} \times 12 \text{ reports/year} = \$10,800$$

The total new cost is between \$6,000 and \$9,000 per year for each operator.

$$\$7,200 - \$1,200 = \$6,000$$

$$\$10,800 - \$1,800 = \$9,000$$

The total cost of this new requirement is equal to the average new cost per operator times the number of operators.

$$73 \text{ operators} \times \$6,000 = \$438,000$$

$$73 \text{ operators} \times \$9,000 = \$657,000$$

Therefore, the total estimated annual cost of this provision is estimated to be between \$438,000 and \$657,000.

The estimated initial cost of this provision on unconventional operators is between \$41.358 million and \$73.463 million; the estimated annual cost of this provision on unconventional operators is between \$5,895,500 and \$31,149,664.

The Department provided a summary table of estimated costs in Appendix A of the Regulatory Analysis Form.

Unconventional operators savings

Assumptions

It is estimated that there will be approximately 2,600 unconventional wells permitted each year for the next 3 years.

Based on Department data, approximately 1 out of every 2 permitted wells gets drilled, or approximately 1,300 wells per year.

The Department assumes there are an average of three unconventional wells per well site. In the future, it is estimated that less well sites will be built as there could be as many as 12 unconventional wells per well pad.

The cost analysis for this final-form rulemaking must be factored on a well site basis, not on a per well basis. Many of the processes proposed for regulation in this final-form rulemaking include activities integral to the operation of several wells and even several well pads.

2,600 wells permitted × 50% of wells drilled = 1,300 wells drilled each year

1,300 wells drilled each year ÷ 3 wells per well site = 434 well sites built each year

Savings estimates

Electronic submission of well permits (§ 78a.15(a))

This final-form rulemaking requires applicants to submit well permit applications electronically through the Department's web site. This will achieve greater efficiency and time management on the Department's end and will also save operators in postage.

2,600 permits × \$5 postage savings = \$13,000

The total savings of this provision is estimated to be \$13,000.

Electronic submission of water surveys as one package (§ 78a.52(d))

An operator may submit a copy of all sample results taken as part of a survey to the Department by electronic means. Currently, operators submit each individual's sample by mail as it is completed. This subsection will save the operator postage cost and will help the Department gain efficiencies by having all samples for one well site area submitted as a whole. The Department estimates that on average, each unconventional well site will fall within the 2,500-foot range (as specified by Act 13) of approximately ten properties.

434 well sites × 10 properties (avg.) × \$5 postage savings = \$21,700

The total savings of this provision is estimated to be \$21,700.

Two-year permit renewal term (§ 78a.17)

This final-form rulemaking allows well permit renewals to be issued for 2 years instead of limiting the renewal term to 1 year. This represents a savings for operators that renew permits because the cost of well permit fees is reduced. The savings associated with this provision is dependent on the number of well permits that get renewed on an annual basis. Based on Department well permit data, unconventional well operators obtain well permit renewals at the following rates.

One renewal = 6.3% of permits

Two renewals = 0.7% of permits

Three or more renewals = 0.3% of permits

Since the first renewal will be issued for a period of 2 years, the cost to renew permits for the second time is eliminated by this final-form rulemaking. Well permits fees for unconventional wells are either \$4,200 for vertical wells or \$5,000 for nonvertical wells.

0.7% × 2,600 × \$4,200 = \$76,440

0.7% × 2,600 × \$5,000 = \$91,000

Therefore, the total savings of this provision is estimated to be between \$76,440 and \$91,000.

Well site restoration extension (§ 78a.65(c)(2))

When initially proposed, the Department estimated that well site restoration extensions would provide a savings of \$21.7 million. Upon further evaluation, since the well site restoration extension provisions are established by the 2012 Oil and Gas Act, any savings that may be realized by this provision are based on statutory provisions and not this final-form rulemaking.

The total savings of this provision is estimated to be \$0.

The estimated savings of this regulation on unconventional operators is approximately \$125,700.

Pipeline/midstream companies savings

Assumptions

There are approximately 100 HDD operations annually.

These operations use approximately 25,000 gallons of drilling fluids to conduct HDD operations.

100 × 25,000 = 2,500,000 gallons per year for disposal

Disposal costs = 12¢ per gallon

Recycling and onsite application of gathering line HDD fluid discharges and returns (§ 78.68a(k))

2,500,000 gallons × 12¢ = \$300,000

The estimated savings of this regulation on pipeline operators and midstream companies is \$300,000 annually.

The total savings for the entire regulated community is estimated to be between \$76,440 and \$477,100.

Local government costs and savings

The Department does not anticipate that there will be significant costs or saving to local governments. The public resource impact screening provisions in § 78a.15(f)(2) may impose a cost on local governments. In accordance with § 78a.15(f), unconventional operators are required to provide public resource information about the location of a proposed well, including identifying the public resource, describing the public resource's function and uses, and describing any mitigation measures. The public resource agency then has the option to provide written comments to the Department on a pending well permit application related to the functions and uses of the public resource and the measure, if any, needed to avoid, minimize or otherwise mitigate probable harmful impacts. To the extent that a local governmental entity manages public resources listed in § 78a.15(f)(1), there may be cost associated with conducting a review of information submitted and preparing written comments to the Department. Any cost would be voluntary as this is not a requirement of this final-form rulemaking.

State government costs and savings

There are costs to the Department that will be incurred as a result of the implementation of this final-form rulemaking. Increased field inspections and formal reviews are anticipated. More importantly however, there are provisions in this final-form rulemaking that will streamline the Department's operations that are anticipated to balance out any increased workload requirements. The following are measures included in this final-form rulemaking with the goal of increasing Department efficiency:

- Electronic permitting will ensure that permits are submitted in a consistent format that prompts correct and complete permit applications prior to their submittal. Electronic permitting will eliminate incomplete application submittals, eliminate paper communications and increase Department complement efficiency. It will also allow for improved transparency in the Department's permitting operations.
- Upon request, require operators to directly provide the Fish and Boat Commission and landowners a copy of the site-specific PPC plan, instead of having them go through a Right-to-Know Law request, will save the Department staff time of obtaining them on their behalf.
- Electronic notification prior to the start of pipeline HDD and liner installation so the Department's staff can schedule inspections accordingly.
- Allow for the approval for aboveground modular storage systems, which, once approved, will be posted on the Department's web site for all users. This will eliminate duplication of work.
- Allow for the one-time approval for pipeline HDD additives which, once approved, will be posted on Department's web site as preapproved. This will eliminate duplication of work.
- Allow for the one-time approval of onsite waste processing facilities. This will eliminate duplication of work.

Compliance assistance plan

The Department has worked extensively with representatives from the regulated community and leaders from several industry organizations have attended the advisory committee meetings when the final-form regulations were discussed. Therefore, the requirements in this final-form rulemaking are well known.

The Department plans to schedule training sessions for the regulated community to address the new regulatory requirements when this final-form rulemaking is finalized. Additionally, Department field staff are the first points of contact for technical assistance and will be able to provide guidance to the regulated community through technical information and direct field-level assistance.

Paperwork requirements

This final-form rulemaking includes new planning, reporting and recordkeeping requirements. However, operators have many different options for their surface operations, therefore not all of the requirements will be applicable all of the time. To minimize the burden of these requirements, the Department has requested electronic submission of most planning, reporting and recordkeeping required in this final-form rulemaking. The Department notes that some reporting and notification requirements are part of the existing regulations but this final-form rulemaking requires electronic submission, so not all of the following items below new reporting require-

ments (for example, permit application requirements in § 78a.15). The Department also notes that lists of preapproved structures or methods will be maintained on the Department's web site and operators utilizing those preapproved items will avoid the need to meet these reporting requirements and use these forms. For example, once a processing method is approved under § 78a.58(g), the operator may use that processing method at other well sites with only notice to the Department rather than another request for approval.

The additional reporting requirements are as follows:

- If an operator wants to use survey results to preserve its defenses under section 3218(d)(1)(i) or (2)(i) of the 2012 Oil and Gas Well Act, submission of predrill well sampling data to the Department. § 78a.52(d) (relating to predrilling or prealteration survey) at least 10 days prior to the start of drilling
- If an owner or operator chooses to dispose of drill cuttings on the well site, they will be required to notify the Department 3 business days prior and provide notice of disposal to the surface landowner with the location of the disposal site within 10 business days of the completion of the disposal. § 78a.61(e)
- An operator of a borrow pit shall register the location of the borrow pit. § 78a.67(b)
- If an operator is using a borrow pit that does not fall under the permitting requirements of the NSMCRA, they will be required to register the location of the borrow pit with the Department. § 78a.67(b)
- Submission to the Department of an area of review report inclusive of a monitoring plan. § 78a.52a(c)
- If an operator wishes to use an alternate temporary storage practice, the operator shall submit a request for approval to the Department. § 78a.56(b)
- If modular aboveground storage structures are to be installed, a 3-business-day notice to the Department is required. § 78a.56(a)(4)
- Operators are required to submit a list to the Department of the well sites where underground or partially buried storage tanks are located. § 78a.57(e)
- Notice of planned use of previously approved or new processing method 3 business days prior to initiation. § 78a.58(d) and (g)
- The Department shall be notified electronically 24 hours prior to all HDD activities. § 78a.68a(c)
- The Department shall be notified of any water supply complaints during HDD. § 78a.68a(j)
- The Department shall be notified of any loss or discharge of HDD fluid during HDD activities. § 78a.68a(i)
- Proof of consultation with the Pennsylvania Natural Heritage Program regarding PNDI and the Pennsylvania Historical and Museum Commission regarding historical/archaeological sites shall be provided to the Department. § 78a.69(c) (relating to water management plans)
- Proof of notification of a proposed withdrawal has been provided to municipalities and counties where water source will be located. § 78a.69(c)
- An operator of an existing freshwater impoundment shall provide electronic notification of the impoundment's GPS coordinates to the township and county in which the impoundment is located. § 78a.59b(b)

- If an operator uses an open pit for storage of production fluids, it shall report the activity to the Department. § 78a.57(a)

- The operator shall notify the Department within 3 business days of the deficiencies found during the monthly inspection of tanks. § 78a.57(i)

- Surface restoration plan. § 78a.65(b)

- The operator shall demonstrate proof of compliance with § 102.8(l) and (m) or provide a licensed professional certification of complete site restoration to approximate original contours and return to preconstruction stormwater runoff rate, volume and quality in accordance with § 102.8(g). § 78a.65(b) and (b)(6)

- If a well site is constructed and the well is not drilled, the well site shall be restored within 9 months after the expiration of the well permit unless the Department approves an extension for reasons of adverse weather or lack of essential fuel, equipment or labor. § 78a.65(a)(3)

- An application for a well permit shall be submitted electronically to the Department through its web site and contain enough information to enable the Department to evaluate the application. § 78a.15(a)

- An operator of a planned unconventional well which will be stimulated using hydraulic fracturing shall develop and submit to the Department an area of review monitoring plan. § 78a.52a(c)(3)

- An operator that constructed a well development impoundment prior to October 8, 2016, shall register the location of the well development impoundment by December 7, 2016, to the Department, through the Department's web site, with electronic notification of the GPS coordinates, township and county where the well development impoundment is located. § 78a.59b(c)

- An operator that constructed a well development impoundment prior to October 8, 2016, shall provide to the Department certification as to whether the impoundment meets the requirements. Any impoundment that does not meet the requirements shall be upgraded to meet the requirements. § 78a.59b(b)

- An operator who plans to close a well development impoundment shall submit electronically to the Department a well development impoundment closure plan. § 78a.59c(a)

- An operator seeking to manage waste on a well site in any manner other than provided in §§ 78a.56—78a.63 shall submit a request electronically to the Department describing the alternate management practice. § 78a.63a (relating to alternative waste management)

- A water purveyor withdrawing water from waters of the Commonwealth shall submit to the Department daily withdrawal volumes on a quarterly basis, in stream flow measurements or other water source purchases, or both. § 78a.69(c)(3)

The regulated community will need new reporting forms with this final-form rulemaking. The Department will make forms and guidance documents available prior to adoption of this final-form rulemaking. The additional forms required are as follows:

- Consideration of Public Resources Form. § 78a.15(f)(3)

- Landowner Questionnaire & Instructions. § 78a.52a(b)(3)

- Survey Plat & Instructions. § 78a.52a(c)(1)

- Proof of Operator Notification Form & Instructions. § 78a.73(c)

- Stimulation Communication Notification Form and Instructions. § 78a.73(c)

- Form/questionnaire to submit to landowners for location of oil and gas wells. § 78a.52a(b)(3)

- Monthly Tank Inspection Form. § 78a.57(i)

- Form to request to process wastewater and drill cuttings. § 78a.58(a) and (e)

- Freshwater Impoundment Registration Form. § 78a.59b(c)

- Land owner request to waive restoration requirement. § 78a.59b(g)

- Mine Influenced Water Storage in a Freshwater Impoundment Form (must include parameters that demonstrate that water stored will not cause pollution). § 78a.59b(h)

- Extension of Drilling or Production Period Request Forms. § 78a.65(c)(1)

- Well Site Restoration Extension Request Form. § 78a.65(d)(3)

- Written Consent of Landowner Restoration. § 78a.65(d)(4)

- Post Drilling Restoration Report. § 78a.65(e)

- Post Plugging Restoration Report. § 78a.65(f)

- Landowner Consent Forms. § 78a.65(g)

- Material Staging Area Setback Waiver Form. § 78a.68a(e)

- Water Management Plan Approval Request Form. § 78a.69(c)

- Request for modification approval of a Water Management Plan. § 78a.69(c)

Landowner notification

Section 78a.52(g) requires unconventional operators to notify landowners that if their water supply becomes impacted and they have refused to allow the operator to perform a predrilling survey of their water supply, the presumption of liability provided by the 2012 Oil and Gas Act will not apply. This provision is needed because this notice is required under section 3218(e.1) of the 2012 Oil and Gas Act. This was a new requirement added in the 2012 Oil and Gas Act.

Department notifications

To enhance the Department's field staff inspection efficiency, this final-form rulemaking requires operators to notify the Department prior to oil and gas construction activities, such as building a well pad or installing a pit liner. These provisions allow the Department to effectively manage its resources and ensure timely inspections.

Three-day notifications are required for the following:

- Prior to disposal of drill cuttings on unconventional well sites. § 78a.61

- Prior to conducting onsite processing on unconventional well sites. § 78a.58

- Prior to utilizing modular aboveground storage structures on unconventional well sites. § 78a.56

- After noticing deficiencies in tanks during monthly inspections on unconventional well sites. § 78a.57(h)

24-hour notice for HDD

In § 78a.68a(c), persons conducting HDD activities associated with pipeline construction relating to unconventional oil and gas operations shall electronically notify the Department through its web site at least 24 hours prior to beginning of any HDD activities, including conventional boring, beneath any body of water or water-course. This provision is needed because it will allow the Department to conduct HDD inspections as the HDD is occurring.

Additionally, in § 78a.68a(j), any water supply complaints received by the responsible party for HDD shall be reported to the Department within 24 hours through the Department's web site. This requirement will ensure that the Department conducts a timely water supply investigation upon receipt of a water supply complaint to the responsible party.

Electronic filing requirements throughout this final-form rulemaking are needed because electronic filing allows the Department to:

- More efficiently track well development and operations from beginning to end, enabling inspectors to focus on field inspections of the hundreds of thousands of wells in this Commonwealth rather than the review and management of paper submissions.
- Provide the public easy access to data through the Department's web site.
- Develop business rules to ensure that the data submitted is complete and accurate, thereby reducing the workload for both the Department and operators in returning and addressing deficient submissions.
- Have a complete picture regarding well development/operations to more efficiently determine compliance. For example, when reviewing production data, Department staff needs to have permit, Well Record, Completion Report and additional information readily available to help determine the validity of the production/waste data. Currently, paper files need to be retrieved, sometimes from other offices, to obtain this information.

In the proposed rulemaking, the well permit and nearly all approvals, reports and notifications required by the proposed rulemaking had to be made to the Department electronically. The Department determined that moving to all electronic filing is appropriate and necessary for the Department to fulfill its mission. Therefore, this final-form rulemaking retains the concept of mandatory electronic submissions to the Department.

The Department also received comments questioning the Department's ability to implement these requirements, as they will require a substantial increase in IT development and support staff than is currently required to support the Oil and Gas Program. The Department currently has a number of online electronic reporting applications for the submission of information pertaining to oil and gas wells. These applications are accessed through the Department's GreenPort enterprise portal. The Department acknowledges that the online electronic reporting functionality with respect to oil and gas operations will need to be expanded. The Department strives to develop applications that are user friendly for both external users and Department staff. The Department will continue in this effort by releasing enhancements to existing applications based upon user feedback. Operators will not be expected to submit information electronically if the Department has not yet developed an electronic portal to accept the information. The Department ac-

knowledges that backup provisions will need to be in place for those situations during which the electronic portal is down.

H. Pollution Prevention

The Pollution Prevention Act of 1990 (42 U.S.C.A. §§ 13101—13109) established a National policy that promotes pollution prevention as the preferred means for achieving state environmental protection goals. The Department encourages pollution prevention, which is the reduction or elimination of pollution at its source, through the substitution of environmentally friendly materials, more efficient use of raw materials and the incorporation of energy efficiency strategies. Pollution prevention practices can provide greater environmental protection with greater efficiency because they can result in significant cost savings to facilities that permanently achieve or move beyond compliance.

The Department notes that section 3211(m)(2)(iv) of the 2012 Oil and Gas Act requires unconventional operators to "include a reuse plan for fluids that will be used to hydraulically fracture wells" as part of the operator's Department-approved WMP. The unconventional oil and gas industry has been extremely effective in utilizing wastewater from one well to hydraulically fracture the next well, achieving almost a 90% recycling rate annually over the past several years. The requirements in this final-form rulemaking are intended to encourage these efforts while maintaining appropriate and reasonable environmental protections in place.

I. Sunset Review

This final-form rulemaking will be reviewed in accordance with the sunset review schedule published by the Department to determine whether it effectively fulfills the goals for which it was intended.

J. Regulatory Review

On December 4, 2013, the Department submitted the proposed rulemaking approved by the Board to the Bureau for publication in the *Pennsylvania Bulletin* for a 60-day public comment period. On the same date, as required under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), the Department submitted the proposed rulemaking and a Regulatory Analysis Form to IRRC and the Chairpersons of the House and Senate Environmental Resources and Energy Committees for review and comment. Notice of the proposed rulemaking was published at 43 Pa.B. 7377. The public comment period was subsequently extended for another 30 days until March 14, 2014, through a notice published at 44 Pa.B. 648.

On March 3, 2016, the Department submitted the pre-Act 52 final-form regulations approved by the Board, the responses to all comments received during the public comment period and a Regulatory Analysis Form to IRRC and the House and Senate Environmental Resources and Energy Committees as required under section 5.1(a) of the Regulatory Review Act (71 P.S. § 745.5a(a)). The pre-Act 52 final-form regulations were prepared based on consideration of all comments received from IRRC, the House and Senate Environmental Resources and Energy Committees, and the public.

On April 12, 2016, the House and Senate Environmental Resources and Energy Committees voted to disapprove the pre-Act 52 final-form regulations and notified IRRC and the Board as required under section 5.1(j.2) of the Regulatory Review Act. On April 21, 2016, IRRC held a

public meeting to consider the pre-Act 52 final-form regulations and approved it in a 3-2 vote.

On May 3, 2016, the House Environmental Resources and Energy Committee voted to report a concurrent resolution to disapprove the pre-Act 52 final-form regulations approved by IRRC to the General Assembly under section 7(d) of the Regulatory Review Act (71 P.S. § 745.7(d)). The concurrent resolution was not passed by the General Assembly within 30 calendar days or 10 legislative days from the reporting of the concurrent resolution, and the Board may therefore promulgate the pre-Act 52 final-form regulations.

On June 23, 2016, Act 52 was enacted abrogating the pre-Act 52 final-form regulations “insofar as such regulations pertain to conventional oil and gas wells.”

The Department delivered the pre-Act 52 final-form regulations to the Office of Attorney General for form and legality review on June 27, 2016. In accordance with the Regulatory Review Act and the Commonwealth Attorneys Act, the Office of Attorney General directed the Department to make changes to the pre-Act 52 final-form regulations to comply with Act 52. On July 26, 2016, the Department resubmitted this final-form rulemaking to the Office of Attorney General for review.

In accordance with the Office of Attorney General’s direction, the Department removed all amendments or additions to Chapter 78 regarding conventional oil and gas wells and retained the deletions and modifications in Chapter 78 that related solely to the unconventional wells. This revised final-form rulemaking also contains clarifications and corrections to respond to other issues identified by the Office of Attorney General, including the addition of § 78a.2 to clarify that Chapter 78a supersedes Chapter 78 for unconventional wells to avoid any potential conflict between the requirements in Chapter 78 and Chapter 78a regarding unconventional wells. Later on July 26, 2016, the Office of Attorney General approved this revised final-form rulemaking for form and legality under the Commonwealth Attorneys Act. The regulations in Annex A are the revised final-form rulemaking as approved by the Office of Attorney General. This preamble was revised to reflect the final-form rulemaking as approved by the Office of Attorney General in conformance with Act 52.

The Joint Committee on Documents met on August 18, 2016, and voted to direct the Bureau to publish this final-form rulemaking.

K. Findings

The Board finds that:

- (1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and regulations promulgated thereunder, 1 Pa. Code §§ 7.1 and 7.2.
- (2) A public comment period was provided as required by law, and all comments were considered.
- (3) This final-form rulemaking does not enlarge the purpose of the proposed rulemaking published at 43 Pa.B. 7377.
- (4) These regulations are necessary and appropriate for administration and enforcement of the authorizing acts identified in Section C of this preamble.

L. Order

The Board, acting under the authorizing statutes, orders that:

(a) The regulations of the Department, 25 Pa. Code, are amended by amending §§ 78.1, 78.19, 78.55, 78.72 and 78.121 and by adding §§ 78a.1, 78a.2, 78a.11—78a.19, 78a.21—78a.33, 78a.51, 78a.52, 78a.52a, 78a.53—78a.58, 78a.59a, 78a.59b, 78a.59c, 78a.60—78a.63, 78a.63a, 78a.64, 78a.64a, 78a.65—78a.68, 78a.68a, 78a.68b, 78a.69, 78a.70, 78a.70a, 78a.71—78a.75, 78a.75a, 78a.76—78a.78, 78a.81—78a.83, 78a.83a, 78a.83b, 78a.83c, 78a.84—78a.89, 78a.91—78a.98, 78a.101—78a.105, 78a.111, 78a.121—78a.124, 78a.301—78a.308 and 78a.310—78a.314 to read as set forth in Annex A.

(Editor’s Note: The provisions added in the new Chapter 78a were initially proposed as amendments to Chapter 78 in the proposed rulemaking published at 43 Pa.B. 7377. In response to comments and Act 126, the pre-Act 52 final-form rulemaking was separated into two chapters. The proposed rescission of §§ 78.2 and 78.309, proposed addition of §§ 78.52a, 78.59a, 78.59b, 78.59c, 78.64a, 78.67, 78.68, 78.68a, 78.68b, 78.69, 78.70 and 78.70a and proposed amendments to §§ 78.13, 78.15, 78.17, 78.18, 78.21, 78.25, 78.28, 78.51—78.53, 78.56—78.58, 78.60—78.66, 78.73, 78.75, 78.76, 78.87, 78.91, 78.101, 78.103, 78.105, 78.122, 78.123, 78.301, 78.302, 78.306, 78.308, 78.310 and 78.402—78.404 have been withdrawn by the Board.)

(b) The Chairperson of the Board shall submit this order and Annex A to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(c) The Chairperson of the Board shall submit this order and Annex A to IRRC and the House and Senate Environmental Resources and Energy Committees as required by the Regulatory Review Act.

(d) The Chairperson of the Board shall certify this order and Annex A and deposit them with the Bureau as required by law.

(e) This order shall take effect immediately upon publication in the *Pennsylvania Bulletin*.

PATRICK McDONNELL,
Acting Chairperson

(Editor’s Note: See 46 Pa.B. 6392 (October 8, 2016) for a notice relating to this final-form rulemaking.)

(Editor’s Note: See 46 Pa.B. 2384 (May 7, 2016) for IRRC’s approval order.)

Fiscal Note: Fiscal Note 7-484 remains valid for the final adoption of the subject regulations.

Annex A

**TITLE 25. ENVIRONMENTAL PROTECTION
PART I. DEPARTMENT OF ENVIRONMENTAL PROTECTION**

Subpart C. PROTECTION OF NATURAL RESOURCES

ARTICLE I. LAND RESOURCES

CHAPTER 78. OIL AND GAS WELLS

Subchapter A. GENERAL PROVISIONS

§ 78.1. Definitions.

The following words and terms, when used in this chapter, have the following meanings, unless the context clearly indicates otherwise, or as otherwise provided in this chapter:

Act—The Oil and Gas Act (58 P.S. §§ 601.101—601.605).

Attainable bottom—The depth, approved by the Department, which can be achieved after a reasonable effort is expended to clean out to the total depth.

Casing seat—The depth to which casing is set.

Cement—A mixture of materials for bonding or sealing that attains a 7-day maximum permeability of 0.01 millidarcies and a 24-hour compressive strength of at least 500 psi in accordance with applicable standards and specifications.

Cement job log—A written record that documents the actual procedures and specifications of the cementing operation.

Certified laboratory—A laboratory accredited by the Department under Chapter 252 (relating to environmental laboratory accreditation).

Coal area—An area that is underlain by a workable coal seam.

Coal protective casing—A string of pipe which is installed in the well for the purpose of coal segregation and protection. In some instances the coal protective casing and the surface casing may be the same.

Conductor pipe—A short string of large-diameter casing used to stabilize the top of the wellbore in shallow unconsolidated formations.

Conventional formation—A formation that is not an unconventional formation.

Conventional well—

(i) A bore hole drilled or being drilled for the purpose of or to be used for construction of a well regulated under 58 Pa.C.S. §§ 3201—3274 (relating to development) that is not an unconventional well, irrespective of technology or design.

(ii) The term includes, but is not limited to:

(A) Wells drilled to produce oil.

(B) Wells drilled to produce natural gas from formations other than shale formations.

(C) Wells drilled to produce natural gas from shale formations located above the base of the Elk Group or its stratigraphic equivalent.

(D) Wells drilled to produce natural gas from shale formations located below the base of the Elk Group where natural gas can be produced at economic flow rates or in economic volumes without the use of vertical or nonvertical well bores stimulated by hydraulic fracture treatments or multilateral well bores or other techniques to expose more of the formation to the well bore.

(E) Irrespective of formation, wells drilled for collateral purposes, such as monitoring, geologic logging, secondary and tertiary recovery or disposal injection.

Deepest fresh groundwater—The deepest fresh groundwater bearing formation penetrated by the wellbore as determined from drillers logs from the well or from other wells in the area surrounding the well or from historical records of the normal surface casing seat depths in the area surrounding the well, whichever is deeper.

Drill cuttings—Rock cuttings and related mineral residues generated during the drilling of an oil or gas well.

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

Gas storage field—A gas storage reservoir and all of the gas storage wells connected to the gas storage reservoir.

Gas storage reservoir—The portion of a subsurface geologic formation or rock strata used for or being tested for storage of natural gas that:

(i) Has sufficient porosity and permeability to allow gas to be injected or withdrawn, or both.

(ii) Is bounded by strata of insufficient porosity or permeability, or both, to allow gas movement out of the reservoir.

(iii) Contains or will contain injected gas geologically or by pressure control.

Gas storage well—A well located and used in a gas storage reservoir for injection or withdrawal purposes, or an observation well.

Gel—A slurry of clay or other equivalent material and water at a ratio of not more than 7 barrels of water to each 100 pounds of clay or other equivalent matter.

Intermediate casing—A string of casing set after the surface casing and before production casing, not to include coal protection casing, that is used in the wellbore to isolate, stabilize or provide well control.

L.E.L.—Lower explosive limit.

Noncementing material—A mixture of very fine to coarse grained nonbonding materials, including unwashed crushed rock, drill cuttings, earthen mud or other equivalent material approved by the Department.

Noncoal area—An area that is not underlain by a workable coal seam.

Nonporous material—Nontoxic earthen mud, drill cuttings, fire clay, gel, cement or equivalent materials approved by the Department that will equally retard the movement of fluids.

Observation well—A well used to monitor the operational integrity and conditions in a gas storage reservoir, the reservoir protective area or strata above or below the gas storage horizon.

Owner—A person who owns, manages, leases, controls or possesses a well or coal property. For purposes of sections 203(a)(4) and (5) and 210 of the act (58 P.S. §§ 601.203(a)(4) and (5) and 601.210), the term does not include those owners or possessors of surface real property on which the abandoned well is located who did not participate or incur costs in the drilling or extraction operation of the abandoned well and had no right of control over the drilling or extraction operation of the abandoned well. The term does not apply to orphan wells except where the Department determines a prior owner or operator benefited from the well as provided in section 210(a) of the act.

Perimeter area—An area that begins at the outside coal boundaries of an operating coal mine and extends within 1,000 feet beyond those boundaries or an area within 1,000 feet beyond the mine permit boundaries of a coal mine already projected and permitted but not yet being operated.

Permanently cemented—Surface casing or coal protective casing that is cemented until cement is circulated to the surface or is cemented with a calculated volume of cement necessary to fill the theoretical annular space plus 20% excess.

Private water supply—A water supply that is not a public water supply.

Production casing—A string of pipe other than surface casing and coal protective casing which is run for the

purpose of confining or conducting hydrocarbons and associated fluids from one or more producing horizons to the surface.

Public water supply—A water system that is subject to the Pennsylvania Safe Drinking Water Act (35 P.S. §§ 721.1—721.17).

Reportable release of brine—Spilling, leaking, emitting, discharging, escaping or disposing of one of the following:

(i) More than 5 gallons of brine within a 24-hour period on or into the ground at the well site where the total dissolved solids concentration of the brine is equal or greater than 10,000 mg/l.

(ii) More than 15 gallons of brine within a 24-hour period on or into the ground at the well site where the total dissolved solids concentration of the brine is less than 10,000 mg/l.

Retrievable—When used in conjunction with surface casing, coal protective casing or production casing, the casing that can be removed after exerting a prudent effort to pull the casing while applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater.

Seasonal high groundwater table—The saturated condition in the soil profile during certain periods of the year. The condition can be caused by a slowly permeable layer within the soil profile and is commonly indicated by the presence of soil mottling.

Sheen—An iridescent appearance on the surface of the water.

Soil mottling—Irregular marked spots in the soil profile that vary in color, size and number.

Surface casing—A string or strings of casing used to isolate the wellbore from fresh groundwater and to prevent the escape or migration of gas, oil or other fluids from the wellbore into fresh groundwater. The surface casing is also commonly referred to as the water string or water casing.

Tophole water—Water that is brought to the surface while drilling through the strata containing fresh groundwater and water that is fresh groundwater or water that is from a body of surface water. Tophole water may contain drill cuttings typical of the formation being penetrated but may not be polluted or contaminated by additives, brine, oil or man induced conditions.

Total depth—The depth to which the well was originally drilled, subsequently drilled or the depth to which it was plugged back in a manner approved by the Department.

Tour—A workshift in drilling of a well.

Unconventional formation—A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore.

Unconventional well—A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation.

Water protection depth—The depth to a point 50 feet below the surface casing seat.

Water purveyor—The owner or operator of a public water supply.

Water supply—A supply of water for human consumption or use, or for agricultural, commercial, industrial or other legitimate beneficial uses.

Well operator or operator—The person designated as the well operator or operator on the permit application or well registration. If a permit or registration was not issued, the term means a person who locates, drills, operates, alters or plugs a well or reconditions a well with the purpose of production therefrom. In cases where a well is used in connection with the underground storage of gas, the term also means a storage operator.

Well site—The area occupied by the equipment or facilities necessary for or incidental to the drilling, production or plugging of a well.

Workable coal seam—One of the following:

(i) A coal seam in fact being mined in the area in question under the act and this chapter by underground methods.

(ii) A coal seam which, in the judgment of the Department, reasonably can be expected to be mined by underground methods.

Subchapter B. PERMITS, TRANSFERS AND OBJECTIONS

PERMITS AND TRANSFERS

§ 78.19. Permit application fee schedule.

(a) An applicant shall pay a permit application fee according to the following schedule:

<i>Conventional Wells</i>	
<i>Total Well Bore Length in Feet</i>	<i>Total Fee</i>
0 to 2,000	\$250
2,001 to 2,500	\$300
2,501 to 3,000	\$350
3,001 to 3,500	\$400
3,501 to 4,000	\$450
4,001 to 4,500	\$500
4,501 to 5,000	\$550
5,001 to 5,500	\$650
5,501 to 6,000	\$750
6,001 to 6,500	\$850
6,501 to 7,000	\$950
7,001 to 7,500	\$1,050
7,501 to 8,000	\$1,150
8,001 to 8,500	\$1,250
8,501 to 9,000	\$1,350
9,001 to 9,500	\$1,450
9,501 to 10,000	\$1,550
10,001 to 10,500	\$1,650
10,501 to 11,000	\$1,750
11,001 to 11,500	\$1,850
11,501 to 12,000	\$1,950

(b) An applicant for a conventional well exceeding 12,000 feet in total well bore length shall pay a permit application fee of \$1,950 + \$100 for every 500 feet the well bore extends over 12,000 feet. Fees shall be rounded to the nearest 500-foot interval under this subsection.

(c) If, when drilled, the total well bore length of the conventional well exceeds the length specified in the permit application due to target formation being deeper than anticipated at the time of application submittal, the operator shall pay the difference between the amount paid as part of the permit application and the amount required under subsections (a) and (b).

(d) An applicant for a conventional well with a well bore length of 1,500 feet or less for home use shall pay a permit application fee of \$200.

(e) At least every 3 years, the Department will provide the EQB with an evaluation of the fees in this chapter and recommend regulatory changes to the EQB to address any disparity between the program income generated by the fees and the Department's cost of administering the program with the objective of ensuring fees meet all program costs and programs are self-sustaining.

Subchapter C. ENVIRONMENTAL PROTECTION PERFORMANCE STANDARDS

§ 78.55. Control and disposal planning.

(a) *Preparation and implementation of plan.* Prior to generation of waste, the well operator shall prepare and implement a plan under § 91.34 (relating to activities utilizing pollutants) for the control and disposal of fluids, residual waste and drill cuttings, including top-hole water, brines, drilling fluids, additives, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.

(b) *Requirements.* The plan must identify the control and disposal methods and practices utilized by the well operator and be consistent with the act, The Clean Streams Law (35 P.S. §§ 691.1—691.1001), the Solid Waste Management Act (35 P.S. §§ 6018.101—6018.1003) and §§ 78.54, 78.56—78.58 and 78.60—78.63. The plan must also include a pressure barrier policy that identifies barriers to be used during identified operations.

(c) *Revisions.* The operator shall revise the plan prior to implementing a change to the practices identified in the plan.

(d) *Copies.* A copy of the plan shall be provided to the Department upon request and shall be available at the site during drilling and completion activities for review.

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

Subchapter D. WELL DRILLING, OPERATION AND PLUGGING

GENERAL

§ 78.72. Use of safety devices—blow-out prevention equipment.

(a) The operator shall use blow-out prevention equipment after setting casing with a competent casing seat in the following circumstances:

(1) When drilling out solid core hydraulic fracturing plugs to complete a well.

(2) When well head pressures or natural open flows are anticipated at the well site that may result in a loss of well control.

(3) When the operator is drilling in an area where there is no prior knowledge of the pressures or natural open flows to be encountered.

(4) On wells regulated by the Oil and Gas Conservation Law (58 P.S. §§ 401—419).

(5) When drilling within 200 feet of a building.

(b) Blow-out prevention equipment used must be in good working condition at all times.

(c) Controls for the blow-out preventer shall be accessible to allow actuation of the equipment. Additional

controls for a blow-out preventer with a pressure rating of greater than 3,000 psi, not associated with the rig hydraulic system, shall be located at least 50 feet away from the drilling rig so that the blow-out preventer can be actuated if control of the well is lost.

(d) The operator shall use pipe fittings, valves and unions placed on or connected to the blow-out prevention systems that have a working pressure capability that exceeds the anticipated pressures.

(e) The operator shall conduct a complete test of the ram type blow-out preventer and related equipment for both pressure and ram operation before placing it in service on the well. The operator shall test the annular type blow-out preventer in accordance with the manufacturer's published instructions, or the instructions of a professional engineer, prior to the device being placed in service. Blow-out prevention equipment that fails the test may not be used until it is repaired and passes the test.

(f) When the equipment is in service, the operator shall visually inspect blow-out prevention equipment during each tour of drilling operation and during actual drilling operations test the pipe rams for closure daily and the blind rams for closure on each round trip. When more than one round trip is made in a day, one daily closure test for blind rams is sufficient. Testing shall be conducted in accordance with American Petroleum Institute publication API RP53, "API Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells," or other procedure approved by the Department. The operator shall record the results of the inspection and closure test in the drillers log before the end of the tour. If blow-out prevention equipment is not in good working order, drilling shall cease when cessation of drilling can be accomplished safely and not resume until the blow-out prevention equipment is repaired or replaced and re-tested.

(g) All lines, valves and fittings between the closing unit and the blow-out preventer stack must be flame resistant and have a rated working pressure that meets or exceeds the requirements of the blow-out preventer system.

(h) When a blowout preventer is installed or required under subsection (a), there shall be present on the well site an individual with a current certification from a well control course accredited by the International Association of Drilling Contractors or other organization approved by the Department. The certification shall be available for review at the well site. The Department will maintain a list of approved accrediting organizations on its web site.

(i) Well drilling and completion operations requiring pressure barriers, as identified by the operator under § 78.55(b) (relating to control and disposal plan), shall employ at least two mechanical pressure barriers between the open producing formation and the atmosphere that are capable of being tested. The mechanical pressure barriers shall be tested according to manufacturer specifications prior to operation. If during the course of operations the operator only has one functioning barrier, operations must cease until additional barriers are added and tested or the redundant barrier is repaired and tested. Stripper rubber or a stripper head may not be considered a barrier.

(j) The minimum amount of intermediate casing that is cemented to the surface to which blow-out prevention equipment may be attached, shall be in accordance with the following:

<i>Proposed Total Vertical Depth (in feet)</i>	<i>Minimum Cemented Casing Required (in feet of casing cemented)</i>
Up to 5,000	400
5,001 to 5,500	500
5,501 to 6,000	600
6,001 to 6,500	700
6,501 to 7,000	800
7,001 to 8,000	1,000
8,001 to 9,000	1,200
9,001 to 10,000	1,400
Deeper than 10,000	1,800

(k) Upon completion of the drilling operations at a well, the operator shall install and utilize equipment, such as a shut-off valve of sufficient rating to contain anticipated pressure, lubricator or similar device, as may be necessary to enable the well to be effectively shut-in while logging and servicing the well and after completion of the well.

Subchapter E. WELL REPORTING

§ 78.121. Production reporting.

(a) The well operator shall submit an annual production and status report for each permitted or registered well on an individual basis, on or before February 15 of each year. When the production data is not available to the operator on a well basis, the operator shall report production on the most well-specific basis available. The annual production report must include information on the amount and type of waste produced and the method of waste disposal or reuse. Waste information submitted to the Department in accordance with this subsection is deemed to satisfy the residual waste biennial reporting requirements of § 287.52 (relating to biennial report).

(b) The production report shall be submitted electronically to the Department through its web site.

CHAPTER 78a. UNCONVENTIONAL WELLS

- Subch. **A. GENERAL PROVISIONS**
- B. PERMITS, TRANSFERS AND OBJECTIONS**
- C. ENVIRONMENTAL PROTECTION PERFORMANCE STANDARDS**
- D. WELL DRILLING, OPERATION AND PLUGGING**
- E. WELL REPORTING**
- G. BONDING REQUIREMENTS**

Subchapter A. GENERAL PROVISIONS

- Sec. 78a.1. Definitions.
- 78a.2. Applicability.

§ 78a.1. Definitions.

The following words and terms, when used in this chapter, have the following meanings, unless the context clearly indicates otherwise, or as otherwise provided in this chapter:

ABACT—Antidegradation best available combination of technologies—The term as defined in § 102.1 (relating to definitions).

Abandoned water well—

(i) A water well that is no longer equipped in such a manner as to be able to draw groundwater.

(ii) The term includes a water well where the pump, piping or electrical components have been disconnected or removed or when its use on a regular or prescribed basis has been discontinued.

(iii) The term does not include a water well that is not currently used, but is equipped or otherwise properly maintained in such a manner as to be able to draw groundwater as an alternative, backup or supplemental water supply.

Accredited laboratory—A laboratory accredited by the Department under Chapter 252 (relating to environmental laboratory accreditation).

Act—58 Pa.C.S. §§ 3201—3274 (relating to development).

Act 2—The Land Recycling and Environmental Remediation Standards Act (35 P.S. §§ 6026.101—6026.908).

Anti-icing—Brine applied directly to a paved road prior to a precipitation event.

Approximate original conditions—Reclamation of the land affected to preconstruction contours so that it closely resembles the general surface configuration of the land prior to construction activities and blends into and complements the drainage pattern of the surrounding terrain, and can support the land uses that existed prior to the applicable oil and gas operations to the extent practicable.

Attainable bottom—The depth, approved by the Department, which can be achieved after a reasonable effort is expended to clean out to the total depth.

Barrel—A unit of volume equal to 42 US liquid gallons.

Body of water—The term as defined in § 105.1 (relating to definitions).

Borrow pit—An area of earth disturbance activity where rock, stone, gravel, sand, soil or similar material is excavated for construction of well sites, access roads or facilities that are related to oil and gas development.

Building—An occupied structure with walls and roof within which persons live or customarily work.

Casing seat—The depth to which casing is set.

Cement—A mixture of materials for bonding or sealing that attains a 7-day maximum permeability of 0.01 millidarcies and a 24-hour compressive strength of at least 500 psi in accordance with applicable standards and specifications.

Cement job log—A written record that documents the actual procedures and specifications of the cementing operation.

Centralized impoundment—A facility authorized by a Permit for a Centralized Impoundment Dam for Oil and Gas Operations (DEP # 8000-PM-OOGM0084).

Certified mail—Any verifiable means of paper document delivery that confirms the receipt of the document by the intended recipient or the attempt to deliver the document to the proper address for the intended recipient.

Coal area—An area that is underlain by a workable coal seam.

Coal protective casing—A string of pipe which is installed in the well for the purpose of coal segregation and protection. In some instances the coal protective casing and the surface casing may be the same.

Common areas of a school's property—An area on a school's property accessible to the general public for recreational purposes. For the purposes of this definition, a school is a facility providing elementary, secondary or postsecondary educational services.

Condensate—A low-density, high-API gravity liquid hydrocarbon phase that generally occurs in association with natural gas. For the purposes of this definition, high-API gravity is a specific gravity scale developed by the American Petroleum Institute for measuring the relative density of various petroleum liquids, expressed in degrees.

Conductor pipe—A short string of large-diameter casing used to stabilize the top of the wellbore in shallow unconsolidated formations.

Deepest fresh groundwater—The deepest fresh groundwater bearing formation penetrated by the wellbore as determined from drillers logs from the well or from other wells in the area surrounding the well or from historical records of the normal surface casing seat depths in the area surrounding the well, whichever is deeper.

De-icing—Brine applied to a paved road after a precipitation event.

Drill cuttings—Rock cuttings and related mineral residues generated during the drilling of an oil or gas well.

Floodplain—The area inundated by the 100-year flood as identified on maps and flood insurance studies provided by the Federal Emergency Management Agency, or in the absence of these maps or studies or any evidence to the contrary, the area within 100 feet measured horizontally from the top of the bank of a perennial stream or 50 feet from the top of the bank of an intermittent stream.

Freeboard—The vertical distance between the surface of an impounded or contained fluid and the lowest point or opening on a lined pit edge or open top storage structure.

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

Gas storage field—A gas storage reservoir and all of the gas storage wells connected to the gas storage reservoir.

Gas storage reservoir—The portion of a subsurface geologic formation or rock strata used for or being tested for storage of natural gas that:

- (i) Has sufficient porosity and permeability to allow gas to be injected or withdrawn, or both.
- (ii) Is bounded by strata of insufficient porosity or permeability, or both, to allow gas movement out of the reservoir.
- (iii) Contains or will contain injected gas geologically or by pressure control.

Gas storage well—A well located and used in a gas storage reservoir for injection or withdrawal purposes, or an observation well.

Gathering pipeline—A pipeline that transports oil, liquid hydrocarbons or natural gas from individual wells to an intrastate transmission pipeline regulated by the Pennsylvania Public Utility Commission or interstate transmission pipeline regulated by the Federal Energy Regulatory Commission.

Gel—A slurry of clay or other equivalent material and water at a ratio of not more than seven barrels of water to each 100 pounds of clay or other equivalent matter.

Inactive well—A well granted inactive status by the Department under section 3214 of the act (relating to inactive status) and § 78a.101 (relating to general provisions).

Intermediate casing—A string of casing set after the surface casing and before production casing, not to include coal protection casing, that is used in the wellbore to isolate, stabilize or provide well control.

L.E.L.—Lower explosive limit.

Limit of disturbance—The boundary within which it is anticipated that earth disturbance activities (including installation of best management practices) will take place.

Mine influenced water—Any of the following:

- (i) Water in a mine pool.
- (ii) Surface discharge of water caused by mining activities that pollutes or may create a threat of pollution to waters of the Commonwealth.
- (iii) A surface water polluted by mine pool water.
- (iv) A surface discharge caused by mining activities.

Modular aboveground storage structure—An aboveground structure used to store wastewater that requires final assembly at a well site to function and which can be disassembled and moved to another well site after use.

Noncementing material—A mixture of very fine to coarse grained nonbonding materials, including unwashed crushed rock, drill cuttings, earthen mud or other equivalent material approved by the Department.

Noncoal area—An area that is not underlain by a workable coal seam.

Nonporous material—Nontoxic earthen mud, drill cuttings, fire clay, gel, cement or equivalent materials approved by the Department that will equally retard the movement of fluids.

Nonvertical unconventional well—

- (i) An unconventional well drilled intentionally to deviate from a vertical axis.
- (ii) The term includes wells drilled diagonally and wells that have horizontal bore holes.

Observation well—A well used to monitor the operational integrity and conditions in a gas storage reservoir, the reservoir protective area, or strata above or below the gas storage horizon.

Oil and gas operations—The term includes the following:

- (i) Well site preparation, construction, drilling, hydraulic fracturing, completion, production, operation, alteration, plugging and site restoration associated with an oil or gas well.
- (ii) Water withdrawals, residual waste processing, water and other fluid management and storage used exclusively for the development of oil and gas wells.
- (iii) Construction, installation, use, maintenance and repair of:
 - (A) Oil and gas well development, gathering and transmission pipelines.
 - (B) Natural gas compressor stations.
 - (C) Natural gas processing plants or facilities performing equivalent functions.

(iv) Construction, installation, use, maintenance and repair of all equipment directly associated with activities in subparagraphs (i)—(iii) to the extent that the equipment is necessarily located at or immediately adjacent to a well site, impoundment area, oil and gas pipeline, natural gas compressor station or natural gas processing plant.

(v) Earth disturbance associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities.

Other critical communities—

(i) Species of special concern identified on a PNDI receipt, including plant or animal species:

(A) In a proposed status categorized as proposed endangered, proposed threatened, proposed rare or candidate.

(B) That are classified as rare or tentatively undetermined.

(ii) The term does not include threatened and endangered species.

Owner—

(i) A person who owns, manages, leases, controls or possesses a well or coal property.

(ii) The term does not apply to orphan wells, except when the Department determines a prior owner or operator benefited from the well as provided in section 3220(a) of the act (relating to plugging requirements).

*PCSM—Post-construction stormwater management—*The term as defined in § 102.1.

*PCSM plan—*The term as defined in § 102.1.

*PNDI—Pennsylvania Natural Diversity Inventory—*The Pennsylvania Natural Heritage Program's database containing data identifying and describing this Commonwealth's ecological information, including plant and animal species classified as threatened and endangered as well as other critical communities provided by the Department of Conservation and Natural Resources, the Fish and Boat Commission, the Game Commission and the United States Fish and Wildlife Service. The database informs the online environmental review tool. The database contains only those known occurrences of threatened and endangered species and other critical communities, and is a component of the Pennsylvania Conservation Explorer.

*PNDI receipt—*The results generated by the Pennsylvania Natural Diversity Inventory Environmental Review Tool containing information regarding threatened and endangered species and other critical communities.

*PPC plan—Preparedness, Prevention and Contingency plan—*A written preparedness, prevention and contingency plan.

*Perimeter area—*An area that begins at the outside coal boundaries of an operating coal mine and extends within 1,000 feet beyond those boundaries or an area within 1,000 feet beyond the mine permit boundaries of a coal mine already projected and permitted but not yet being operated.

*Permanently cemented—*Surface casing or coal protective casing that is cemented until cement is circulated to the surface or is cemented with a calculated volume of cement necessary to fill the theoretical annular space plus 20% excess.

*Pit—*A natural topographic depression, manmade excavation or diked area formed primarily of earthen materials designed to hold fluids, semifluids or solids.

Playground—

(i) An outdoor area provided to the general public for recreational purposes.

(ii) The term includes community-operated recreational facilities.

*Pre-wetting—*Mixing brine with antiskid material prior to roadway application.

*Primary containment—*A pit, tank, vessel, modular aboveground storage structure, temporary storage facility or other equipment designed to hold regulated substances including all piping and other appurtenant facilities located on the well site.

*Private water supply—*A water supply that is not a public water supply.

*Process or processing—*The term has the same meaning as "processing" as defined in section 103 of the Solid Waste Management Act (35 P.S. § 6018.103).

*Production casing—*A string of pipe other than surface casing and coal protective casing which is run for the purpose of confining or conducting hydrocarbons and associated fluids from one or more producing horizons to the surface.

*Public resource agency—*An entity responsible for managing a public resource identified in § 78a.15(d) or (f)(1) (relating to application requirements) including the Department of Conservation and Natural Resources, the Fish and Boat Commission, the Game Commission, the United States Fish and Wildlife Service, the United States National Park Service, the United States Army Corps of Engineers, the United States Forest Service, counties, municipalities and playground owners.

*Public water supply—*A source of water used by a water purveyor.

Regional groundwater table—

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

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

*Regulated substance—*The term as defined in section 103 of Act 2 (35 P.S. § 6026.103).

*Residual waste—*The term as defined in § 287.1 (relating to definitions).

*Retrievable—*When used in conjunction with surface casing, coal protective casing or production casing, the casing that can be removed after exerting a prudent effort to pull the casing while applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater.

*Seasonal high groundwater table—*The saturated condition in the soil profile during certain periods of the year. The condition can be caused by a slowly permeable layer within the soil profile and is commonly indicated by the presence of soil mottling.

*Secondary containment—*A physical barrier specifically designed to minimize releases into the environment of regulated substances from primary containment or well development pipelines, to prevent comingling of incompat-

ible released regulated substances and to minimize the area of potential contamination, to the extent practicable.

Sheen—An iridescent appearance on the surface of the water.

Soil mottling—Irregular marked spots in the soil profile that vary in color, size and number.

Stormwater—Runoff from precipitation, snowmelt, surface runoff and drainage.

Surface casing—A string or strings of casing used to isolate the wellbore from fresh groundwater and to prevent the escape or migration of gas, oil or other fluids from the wellbore into fresh groundwater. The surface casing is also commonly referred to as the water string or water casing.

Threatened or endangered species—Those animal and plant species identified as a threatened or endangered species as determined under the Endangered Species Act of 1973 (16 U.S.C.A. §§ 1531—1544), the Wild Resource Conservation Act (32 P.S. §§ 5301—5314), 30 Pa.C.S. (relating to Fish and Boat Code) and 34 Pa.C.S. (relating to Game and Wildlife Code).

Tophole water—Water that is brought to the surface while drilling through the strata containing fresh groundwater and water that is fresh groundwater or water that is from a body of surface water. Tophole water may contain drill cuttings typical of the formation being penetrated but may not be polluted or contaminated by additives, brine, oil or man-induced conditions.

Total depth—The depth to which the well was originally drilled, subsequently drilled or the depth to which it was plugged back in a manner approved by the Department.

Tour—A workshift in drilling of a well.

Unconventional formation—A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore.

Unconventional well or well—A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation.

Vertical unconventional well—An unconventional well with a single vertical well bore.

WMP—Water management plan—A plan associated with drilling or completing a well in an unconventional formation that demonstrates that the withdrawal and use of water sources within this Commonwealth protects those sources, as required under law, and protects public health, safety and welfare.

Water protection depth—The depth to a point 50 feet below the surface casing seat.

Water purveyor—Either of the following:

(i) The owner or operator of a public water system as defined in section 3 of the Pennsylvania Safe Drinking Water Act (35 P.S. § 721.3).

(ii) Any person subject to the act of June 24, 1939 (P.L. 842, No. 365) (32 P.S. §§ 631—641), known as the Water Rights Law.

Water source—

(i) Any of the following:

(A) Waters of the Commonwealth.

(B) A source of water supply used by a water purveyor.

(C) Mine pools and discharges.

(D) Any other waters that are used for drilling or completing a well in an unconventional formation.

(ii) The term does not include flowback or production waters or other fluids:

(A) Which are used for drilling or completing a well in an unconventional formation.

(B) Which do not discharge into waters of the Commonwealth.

Water supply—A supply of water for human consumption or use, or for agricultural, commercial, industrial or other legitimate beneficial uses.

Watercourse—The term as defined in § 105.1.

Waters of the Commonwealth—The term as defined in section 1 of The Clean Streams Law (35 P.S. § 691.1).

Well development impoundment—A facility that is:

(i) Not regulated under § 105.3 (relating to scope).

(ii) A natural topographic depression, manmade excavation or diked area formed primarily of earthen materials although lined with synthetic materials.

(iii) Designed to hold surface water, fresh groundwater and other fluids approved by the Department.

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

Well development pipelines—Pipelines used for oil and gas operations that:

(i) Transport materials used for the drilling or hydraulic fracture stimulation, or both, of a well and the residual waste generated as a result of the activities.

(ii) Lose functionality after the well site it serviced has been restored under § 78a.65 (related to site restoration).

Well operator or operator—Any of the following:

(i) The person designated as the operator or well operator on the permit application or well registration.

(ii) If a permit or registration was not issued, a person who locates, drills, operates, alters or plugs a well or reconditions a well with the purpose of production from the well.

(iii) If a well is used in connection with the underground storage of gas, a storage operator.

Well site—The area occupied by the equipment or facilities necessary for or incidental to the drilling, production or plugging of a well.

Wellhead protection area—The term as defined in § 109.1 (relating to definitions).

Wetland—The term as defined in § 105.1.

Workable coal seam—Either of the following:

(i) A coal seam in fact being mined in the area in question under the act and this chapter by underground methods.

(ii) A coal seam which, in the judgment of the Department, reasonably can be expected to be mined by underground methods.

§ 78a.2. Applicability.

This chapter applies to unconventional wells and supercedes any regulations in Chapter 78 (relating to oil and gas wells) applicable to unconventional wells.

Subchapter B. PERMITS, TRANSFERS AND OBJECTIONS

PERMITS AND TRANSFERS

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PERMITS AND TRANSFERS

§ 78a.11. Permit requirements.

(a) No person may drill or alter a well unless that person has first obtained a permit from the Department.

(b) No person may operate a well unless one of the following conditions has been met:

- (1) The person has obtained a permit under the act.
- (2) The person has registered the well under the act.

(3) The well was in operation on April 18, 1985, under a permit that was obtained under the Gas Operations Well-Drilling Petroleum and Coal Mining Act (52 P.S. §§ 2104, 2208, 2601 and 2602) (Repealed).

§ 78a.12. Compliance with permit.

A person may not drill, alter or operate a well except in accordance with a permit or registration issued under the act and in compliance with the terms and conditions of the permit, this chapter and the statutes under which it was promulgated. A copy of the permit shall be kept at the well site during drilling or alteration of a well.

§ 78a.13. Permit transfers.

(a) No transfer, assignment or sale of rights granted under a permit or registration may be made without prior written approval of the Department. Permit transfers may be denied for the reasons set forth in section 3211(e.1)(4) and (5) of the act (relating to well permits).

(b) The Department may require the transferee to fulfill the drilling, plugging, well site restoration, water supply replacement and other requirements of the act, regardless of whether the transferor started the activity and regardless of whether the transferor failed to properly perform the transferor's obligations under the act.

§ 78a.14. Transfer of well ownership or change of address.

(a) Within 30 days after the sale, assignment, transfer, conveyance or exchange of a well, the new owner or operator shall notify the Department, in writing, of the transfer of ownership.

(b) The notice must include the following information:

- (1) The names, addresses and telephone numbers of the former and new owner, and the agent if applicable.
- (2) The well permit or registration number.
- (3) The effective date of the transfer of ownership.
- (4) An application for a well permit transfer if there is a change in the well operator.

(c) The permittee shall notify the Department of a change in address or name within 30 days of the change.

§ 78a.15. Application requirements.

(a) An application for a well permit shall be submitted electronically to the Department on forms provided through its web site and contain the information required by the Department to evaluate the application.

(b) The permit application will not be considered complete until the applicant submits a complete and accurate plat, an approvable bond or other means of complying with Subchapter G (relating to bonding requirements) and section 3225 of the act (relating to bonding), the fee in compliance with § 78a.19 (relating to permit application fee schedule), proof of the notifications required under section 3211(b.1) of the act (relating to well permits), necessary requests for variance or waivers or other documents required to be furnished by law or the Department and the information in subsections (b.1), (b.2), (c)—(f) and (h). The person named in the permit shall be the same person named in the bond or other security.

(b.1) If the proposed limit of disturbance of the well site is within 100 feet measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland 1 acre or greater in size, the applicant shall demonstrate that the well site location will protect those watercourses or bodies of water. The applicant may rely upon other plans developed under this chapter or approved by the Department to make this demonstration, including:

(1) An erosion and sediment control plan or permit consistent with Chapter 102 (relating to erosion and sediment control).

(2) A water obstruction and encroachment permit issued under Chapter 105 (relating to dam safety and waterway management).

(3) Applicable portions of the PPC plan prepared in accordance with § 78a.55(a) and (b) (relating to control and disposal planning; emergency response for unconventional wells).

(4) Applicable portions of the emergency response plan prepared in accordance with § 78a.55(i).

(5) Applicable portions of the site containment plan prepared in accordance with section 3218.2 of the act (relating to containment for unconventional wells).

(b.2) For purposes of compliance with section 3215(a) of the act (relating to well location restrictions), an abandoned water well does not constitute a water well.

(c) The applicant shall submit information identifying parent and subsidiary business corporations operating in this Commonwealth with the first application submitted after October 8, 2016, and provide any changes to this information with each subsequent application.

(d) The well permit application must include a detailed analysis of the impact of the well, well site and access road on threatened and endangered species. This analysis must include:

(1) A PNDI receipt.

(2) If any potential impact is identified in the PNDI receipt to threatened or endangered species, demonstration of how the impact will be avoided or minimized and mitigated in accordance with State and Federal laws pertaining to the protection of threatened or endangered species and critical habitat. The applicant shall provide written documentation to the Department supporting this demonstration, including any avoidance/mitigation plan, clearance letter, determination or other correspondence resolving the potential species impact with the applicable public resource agency.

(e) If an applicant seeks to locate a well on an existing well site where the applicant has obtained a permit under § 102.5 (relating to permit requirements) and complied with § 102.6(a)(2) (relating to permit applications and fees), the applicant may comply with subsections (b.1) and (d) if the permit was obtained within 2 years from the receipt of the application submitted under this section.

(f) An applicant proposing to drill a well at a location that may impact a public resource as provided in paragraph (1) shall notify the applicable public resource agency, if any, in accordance with paragraph (2). The applicant shall also provide the information in paragraph (3) to the Department in the well permit application.

(1) This subsection applies if the proposed limit of disturbance of the well site is located:

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

(ii) In or within the corridor of a State or National scenic river.

(iii) Within 200 feet of a National natural landmark.

(iv) In a location that will impact other critical communities.

(v) Within 200 feet of a historical or archeological site listed on the Federal or State list of historic places.

(vi) Within 200 feet of common areas on a school's property or a playground.

(vii) Within zones 1 or 2 of a wellhead protection area as part of a wellhead protection program approved under § 109.713 (relating to wellhead protection program).

(viii) Within 1,000 feet of a water well, surface water intake, reservoir or other water supply extraction point used by a water purveyor.

(2) The applicant shall notify the public resource agency responsible for managing the public resource identified in paragraph (1), if any. The applicant shall forward by certified mail a copy of the plat identifying the proposed limit of disturbance of the well site and information in paragraph (3) to the public resource agency at least 30 days prior to submitting its well permit application to the Department. The applicant shall submit proof of notification with the well permit application. From the date of notification, the public resource agency has 30

days to provide written comments to the Department and the applicant on the functions and uses of the public resource and the measures, if any, that the public resource agency recommends the Department consider to avoid, minimize or otherwise mitigate probable harmful impacts to the public resource where the well, well site and access road is located. The applicant may provide a response to the Department to the comments.

(3) The applicant shall include the following information in the well permit application on forms provided by the Department:

(i) An identification of the public resource.

(ii) A description of the functions and uses of the public resource.

(iii) A description of the measures proposed to be taken to avoid, minimize or otherwise mitigate impacts, if any.

(4) The information required under paragraph (3) shall be limited to the discrete area of the public resource that may be affected by the well, well site and access road.

(g) The Department will consider the following prior to conditioning a well permit based on impacts to public resources:

(1) Compliance with all applicable statutes and regulations.

(2) The proposed measures to avoid, minimize or otherwise mitigate the impacts to public resources.

(3) Other measures necessary to protect against a probable harmful impact to the functions and uses of the public resource.

(4) The comments and recommendations submitted by public resource agencies, if any, and the applicant's response, if any.

(5) The optimal development of the gas resources and the property rights of gas owners.

(h) An applicant proposing to drill a well that involves 1 acre to less than 5 acres of earth disturbance over the life of the project and is located in a watershed that has a designated or existing use of high quality or exceptional value under Chapter 93 (relating to water quality standards) shall submit an erosion and sediment control plan consistent with Chapter 102 with the well permit application for review and approval and shall conduct the earth disturbance in accordance with the approved erosion and sediment control plan.

§ 78a.16. Accelerated permit review.

In cases of hardship, an operator may request an accelerated review of a well permit application. For the purposes of this section, hardship includes cases where immediate action is necessary to protect public health or safety, to control pollution or to effect other environmental or safety measures, and extraordinary circumstances beyond the control of the operator. Permits issued shall be consistent with the requirements of the act.

§ 78a.17. Permit expiration and renewal.

(a) A well permit expires 1 year after issuance if drilling has not started. If drilling is started within 1 year after issuance, the well permit expires unless drilling is pursued with due diligence. Due diligence for the purposes of this subsection means completion of drilling the well to total depth within 16 months of issuance. A permittee may request an extension of the 16-month

expiration from the Department for good cause. This request shall be submitted electronically to the Department through its web site.

(b) An operator may request a single 2-year renewal of an unexpired well permit. The request shall be accompanied by a permit fee, the surcharge required under section 3271 of the act (relating to well plugging funds) and an affidavit affirming that the information on the original application is still accurate and complete, that the well location restrictions are still met and that the entities required to be notified under section 3211(b)(2) of the act (relating to well permits) have been notified of this request for renewal. If new water wells or buildings are constructed that are not indicated on the plat as originally submitted, the attestation shall be updated as part of the renewal request. Any new water well or building owners shall be notified of the renewal request; however, the setbacks outlined in section 3215(a) of the act (relating to well location restrictions) do not apply provided that the original permit was issued prior to the construction of the building or water well. The request shall be received by the Department at least 15 calendar days prior to the expiration of the original permit.

§ 78a.18. Disposal and enhanced recovery well permits.

Disposal or enhanced recovery well permits shall meet the requirements of § 78.18 (relating to disposal and enhanced recovery well permits).

§ 78a.19. Permit application fee schedule.

(a) An applicant for an unconventional well shall pay a permit application fee according to the following:

- (1) \$4,200 for a vertical unconventional well.
- (2) \$5,000 for a nonvertical unconventional well.

(b) At least every 3 years, the Department will provide the EQB with an evaluation of the fees in this chapter and recommend regulatory changes to the EQB to address any disparity between the program income generated by the fees and the Department's cost of administering the program with the objective of ensuring fees meet all program costs and programs are self-sustaining.

OBJECTIONS

§ 78a.21. Opportunity for objections and conferences; surface landowners.

(a) The surface landowner of the tract on which the proposed well is located may object to the well location based on the assertion that the well location violates section 3215 of the act (relating to well location restrictions) or on the basis that the information in the application is untrue in a material respect, and request a conference under section 3251 of the act (relating to conferences).

(b) The objection and request for a conference shall be filed in writing with the Department within 15 calendar days of receipt of the plat by the surface landowner. The objection must contain the following:

- (1) The name, address and telephone number of the person submitting the objection.
- (2) The name of the well operator, and the name and number of the proposed well.
- (3) A statement of the objection and a request for a conference if a conference is being requested.

§ 78a.22. Objections by owner or operator of coal mine.

The owner or operator of an operating coal mine or a coal mine already projected and platted, but not yet being

operated, may file written objections to a proposed well location with the Department if the following apply:

(1) The well, when drilled, would penetrate within the outside coal boundaries of such a mine or within 1,000 feet beyond the boundaries.

(2) In the opinion of the owner or operator, the well will unduly interfere with or endanger the mine or persons working in the mine.

§ 78a.23. Time for filing objections by owner or operator of coal mine.

(a) A coal mine owner or operator who objects to a proposed gas well for financial considerations, and wishes to go before a panel with an objection over which the panel has jurisdiction, shall file objections to a proposed gas well within 10 calendar days of the receipt of the plat.

(b) A coal mine owner or operator who does not wish to go before a panel with an objection over which the panel has jurisdiction, or who is not raising financial objections to the proposed gas well, shall file objections to a proposed well within 15 calendar days of the receipt of the plat.

§ 78a.24. Information to be provided with objections by owner or operator of coal mine.

(a) The objections shall be filed in writing and must contain the following information, if applicable:

- (1) The name, address and telephone number of the person filing the objection, and the date on which a copy of the plat was received.
- (2) The name and address of the applicant for the well permit and the name and number of the well.
- (3) The type of well—for example, oil, gas, injection, and the like—that is the subject of the objections.
- (4) The location of the well in relation to the coal owned or operated by the objecting party.
- (5) The area through which the well will be drilled, specifically:
 - (i) Whether the well will be drilled through a mining area that is projected, platted or permitted, but not yet being operated.
 - (ii) Whether the well will be drilled through a perimeter area.
 - (iii) Whether the well will penetrate a workable coal seam.
 - (iv) Whether the well will be located above an active mine.
 - (v) Whether the well will penetrate an operating mine.
- (6) A copy of the plans, maps or projections of the mining area underlying the proposed gas well showing the location of the proposed well.
- (7) Whether the owner or operator believes that the well will pose undue interference or endangerment to the mine, and the nature of the threat.
- (8) The financial impact posed by the well, to which objections may be heard by a panel under § 78a.30 (relating to jurisdiction of panel).
- (9) Whether the well will violate the act, the Coal and Gas Resource Coordination Act (58 P.S. §§ 501—518) or another applicable law administered by the Department.

(b) The objections must include an alternate location, if possible, on the tract of the well operator that would overcome the objections or at which the interference

would be minimized. The Department is not bound to consider alternate locations that are proposed after the close of the first conference.

§ 78a.25. Conferences—general.

(a) If a timely objection to the location is filed by the coal owner or operator under §§ 78a.22—78a.24 (relating to objections by owner or operator of coal mine; time for filing objections by owner or operator of coal mine; and information to be provided with objections by owner or operator of coal mine), or if objections are made by the Department, the Department will fix a time and place for a conference within 10 calendar days from the date of service of the objections upon the well operator, unless all parties agree to an extension of time for the conference.

(b) The Department may decide not to hold a conference if it determines that the objections are not valid or if the objection is resolved.

(c) The Department will attempt to schedule the conference as late as possible in the 10-day period if the well is subject to the Coal and Gas Resource Coordination Act (58 P.S. §§ 501—518). The Department will not schedule a conference under section 3212 of the act (relating to permit objections) if it receives written notice that the gas well operator or the coal mine owner or operator has made a written request to convene a panel to resolve objections to the location of a gas well over which a panel has jurisdiction in accordance with §§ 78a.29—78a.33.

(d) The conference will be governed by §§ 78a.26—78a.28 (relating to agreement at conference; continuation of conference; and final action if objections do not proceed to panel).

(e) The Department or a person having a direct interest in the subject matter of the act may request a conference any time to attempt to resolve by mutual agreement a matter arising under the act.

§ 78a.26. Agreement at conference.

(a) If the parties reach an agreement at the conference, and if the Department approves the location, the Department will cause the agreement to be reduced to writing.

(b) If the Department does not reject the agreement within 10 calendar days after the agreement is reduced to writing, the agreement becomes effective.

(c) An agreement reached at the conference shall be consistent with the requirements of the act and applicable statutes. An agreement that is not in accordance with the act, the Coal and Gas Resource Coordination Act (58 P.S. §§ 501—518) and applicable law shall be deemed to be null and void.

§ 78a.27. Continuation of conference.

The Department may continue the conference for good cause. Good cause includes one or more of the following:

- (1) The need for supplemental data, maps or surveys.
- (2) The need to verify that the agreement or a proposed well location is consistent with the requirements of the act, the Coal and Gas Resource Coordination Act (58 P.S. §§ 501—518) and other applicable requirements.
- (3) The need for the presence of essential witnesses whose unavailability is due to good cause.
- (4) The need for further investigation into the allegations that are the basis for the objections.
- (5) Agreement by all parties that a continuance is beneficial to the resolution of the objections.

§ 78a.28. Final action if objections do not proceed to panel.

If the panel does not have jurisdiction over the objections, under § 78a.30 (relating to jurisdiction of panel), or if the panel has jurisdiction but the parties choose not to proceed to a panel, the Department may proceed to issue or deny the permit, under sections 3211 and 3212 of the act (relating to well permits; and permit objections). No permit will be issued for a well at a location that in the opinion of the Department would endanger the safety of persons working in a coal mine.

§ 78a.29. Composition of panel.

(a) If the gas well operator and the objecting coal owner or operator are unable to agree upon a drilling location, and the gas well is subject to the jurisdiction of a panel under § 78a.30 (relating to jurisdiction of panel), the well operator or a coal owner or operator may convene a panel.

(b) The panel shall consist of one person selected by the objecting coal owners or operators, a second person selected by the permit applicant and a third selected by these two.

(c) The parties shall submit their positions to the panel within such time as the panel prescribes, in accordance with section 12 of the Coal and Gas Resource Coordination Act (58 P.S. § 512).

§ 78a.30. Jurisdiction of panel.

(a) A panel shall hear objections by the owner or operator of the coal mining area only if the proposed gas well is not subject to the Oil and Gas Conservation Law (58 P.S. §§ 401—419) and one of the following applies:

(1) The well will be drilled through an area that is projected and permitted, but not yet being operated.

(2) The well will be drilled through a perimeter area.

(3) The well will penetrate a workable coal seam, and will be located above an active mine, but will not penetrate an operating mine.

(b) The panel shall hear only objections that were filed by the owner or operator of the mining areas set forth in subsection (a).

(c) If after a conference in accordance with § 78a.25 (relating to conferences—general), the Department has unresolved objections, the panel does not have jurisdiction to convene or to hear objections.

§ 78a.31. Scheduling of meeting by the panel.

The panel shall convene a meeting within 10 calendar days of the panel chairperson's receipt of a written request to do so by the permit applicant or by the objecting coal owner or operator.

§ 78a.32. Recommendation by the panel.

(a) The panel shall make its recommendation of where the proposed well should be located, based upon the financial considerations of the parties.

(b) The panel shall make its recommendation within 10 calendar days of the close of the meeting held under § 78a.31 (relating to scheduling of meeting by the panel).

(c) If the Department determines that the first recommended location endangers a mine or the public, it will reject the location and notify the panel to make another recommendation. The panel shall submit another recommended location to the Department within 10 calendar days of the Department's notification.

(d) If the Department determines that the second recommended location endangers a mine or the public, the Department may designate a location where it has determined that the well will not unduly interfere with or endanger the mine or the public and issue a permit for the well at that designated location. However, if the Department has not designated such a location, and if the Department determines that a well drilled at any proposed or panel-recommended alternate location will unduly interfere with or endanger the mine or the public, it will deny the permit.

(e) No permit will be issued for a well at a location that would, in the opinion of the Department, endanger the safety of persons working in a coal mine.

§ 78a.33. Effect of panel on time for permit issuance.

The period of time during which the objections are being considered by a full panel will not be included in the 45-day period for the issuance or denial of a permit under section 3211(e) of the act (relating to well permits).

Subchapter C. ENVIRONMENTAL PROTECTION PERFORMANCE STANDARDS

Sec.	
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78a.70.	Road-spreading of brine for dust control and road stabilization.
78a.70a.	Pre-wetting, anti-icing and de-icing.

§ 78a.51. Protection of water supplies.

(a) A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply as determined by the Department.

(b) A landowner, water purveyor or affected person suffering pollution or diminution of a water supply as a result of oil and gas operations may so notify the Department and request that an investigation be conducted. Notice shall be made to the appropriate Department regional office or by calling the Department's State-wide toll free number at (800) 541-2050. The notice and request must include the following:

- (1) The name, address and telephone number of the person requesting the investigation.
- (2) The type, location and use of the water supply.
- (3) Available background quality and quantity data regarding the water supply, if known.

- (4) Well depth, pump setting and water level, if known.
- (5) A description of the pollution or diminution.

(c) Within 10 calendar days of the receipt of the investigation request, the Department will investigate the claim and will, within 45 calendar days of receipt of the request, make a determination. If the Department finds that pollution or diminution was caused by the oil and gas operations or if it presumes the well operator responsible for polluting the water supply of the landowner or water purveyor under section 3218(c) of the act (relating to protection of water supplies) as a result of completion, drilling, stimulation or alteration of the unconventional well, the Department will issue orders to the well operator necessary to assure compliance with this section. The presumption established by section 3218(c) of the act is not applicable to pollution resulting from well site construction.

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

(1) *Reliability, cost, maintenance and control.* A restored or replaced water supply, at a minimum, must:

- (i) Be as reliable as the previous water supply.
- (ii) Be as permanent as the previous water supply.
- (iii) Not require excessive maintenance.

(iv) Provide the water user with as much control and accessibility as exercised over the previous water supply.

(v) Not result in increased costs to operate and maintain. If the operating and maintenance costs of the restored or replaced water supply are increased, the operator shall provide for permanent payment of the increased operating and maintenance costs of the restored or replaced water supply.

(2) *Quality.* The quality of a restored or replaced water supply will be deemed adequate if it meets the standards established under the Pennsylvania Safe Drinking Water Act (35 P.S. §§ 721.1—721.17), or is comparable to the quality of water that existed prior to pollution if the water quality was better than these standards.

(3) *Adequate quantity.* A restored or replaced water supply will be deemed adequate in quantity if it meets one of the following as determined by the Department:

(i) It delivers the amount of water necessary to satisfy the water user's needs and the demands of any reasonably foreseeable uses.

(ii) It is established through a connection to a public water supply system that is capable of delivering the amount of water necessary to satisfy the water user's needs and the demands of any reasonably foreseeable uses.

(iii) For purposes of this paragraph and with respect to agricultural water supplies, the term "reasonably foreseeable uses" includes the reasonable expansion of use where the water supply available prior to drilling exceeded the actual use.

(4) *Water source serviceability.* Replacement of a water supply includes providing plumbing, conveyance, pumping or auxiliary equipment and facilities necessary for the water user to utilize the water supply.

(e) If the water supply is for uses other than human consumption, the operator shall demonstrate to the De-

partment's satisfaction that the restored or replaced water supply is adequate for the purposes served by the supply.

(f) Tank trucks or bottled water are acceptable only as temporary water replacement for a period approved by the Department and do not relieve the operator of the obligation to provide a restored or replaced water supply.

(g) If the well operator and the water user are unable to reach agreement on the means for restoring or replacing the water supply, the Department or either party may request a conference under section 3251 of the act (relating to conferences).

(h) A well operator who receives notice from a landowner, water purveyor or affected person that a water supply has been affected by pollution or diminution shall report receipt of notice from an affected person to the Department within 24 hours of receiving the notice. Notice shall be provided electronically to the Department through its web site.

§ 78a.52. Predrilling or prealteration survey.

(a) A well operator who wishes to preserve its defense under section 3218(d)(2)(i) of the act (relating to protection of water supplies) that the pollution of a water supply existed prior to the drilling or alteration of the well shall conduct a predrilling or prealteration survey in accordance with this section. For the purposes of this section, "survey" means all of the predrilling or prealteration water supply samples associated with a single well.

(b) A person who wishes to document the quality of a water supply to support a future claim that the drilling or alteration of the well affected the water supply by pollution may conduct a predrilling or prealteration survey in accordance with this section.

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

(d) An operator electing to preserve its defenses under section 3218(d)(2)(i) of the act shall provide a report containing a copy of all the sample results taken as part of the survey electronically to the Department on forms provided through its web site 10 business days prior to the start of drilling of the well that is the subject of the survey. The operator shall provide a copy of any sample results to the landowner or water purveyor within 10 business days of receipt of the sample results. Survey results not received by the Department within 10 business days may not be used to preserve the operator's defenses under section 3218(d)(2)(i) of the act.

(e) The report describing the results of the survey must contain the following information:

(1) The location of the water supply and the name of the surface landowner or water purveyor.

(2) The date of the survey, and the name of the independent Pennsylvania-accredited laboratory and the person who conducted the survey.

(3) A description of where and how the samples were collected.

(4) A description of the type and age, if known, of the water supply, and treatment, if any.

(5) The name of the well operator, name and number of well to be drilled and permit number if known.

(6) The results of the laboratory analysis.

(f) A well operator who wishes to preserve the defense under section 3218(d)(2)(ii) of the act that the landowner or water purveyor refused the operator access to conduct a survey shall confirm the desire to conduct this survey and that access was refused by issuing notice to the person by certified mail, or otherwise document that access was refused. The notice must include the following:

(1) The operator's intention to drill or alter a well.

(2) The desire to conduct a predrilling or prealteration survey.

(3) The name of the person who requested and was refused access to conduct the survey and the date of the request and refusal.

(4) The name and address of the well operator and the address of the Department, to which the water purveyor or landowner may respond.

(g) The operator of an unconventional well shall provide written notice to the landowner or water purveyor indicating that the presumption established under section 3218(c) of the act may be void if the landowner or water purveyor refused to allow the operator access to conduct a predrilling or prealteration survey. Proof of written notice to the landowner or water purveyor shall be provided to the Department for the operator to retain the protections under section 3218(d)(2)(ii) of the act. Proof of written notice will be presumed if provided in accordance with section 3212(a) of the act (relating to permit objections).

§ 78a.52a. Area of review.

(a) The operator shall identify the surface and bottom hole locations of any of the following having well bore paths within 1,000 feet measured horizontally from the vertical well bore and 1,000 feet measured from the surface above the entire length of a horizontal well bore:

(1) Active wells.

(2) Inactive wells.

(3) Orphan wells.

(4) Abandoned wells.

(5) Plugged and abandoned wells.

(b) Identification of wells listed in subsection (a) must be accomplished by the following:

(1) Conducting a review of the Department's well databases and other available well databases.

(2) Conducting a review of historical sources of information, such as applicable farm line maps, where accessible.

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

(c) The operator shall submit a report summarizing the review, including:

(1) A plat showing the location and GPS coordinates of all wells identified under subsection (b).

(2) Proof that the operator submitted questionnaires under subsection (b)(3).

(3) A monitoring plan for wells required to be monitored under § 78a.73(c) (relating to general provision for

well construction and operation), including the methods the operator will employ to monitor these wells.

(4) To the extent that information is available, the true vertical depth of identified wells.

(5) The sources of the information provided for identified wells.

(6) To the extent that information is available, surface evidence of failed well integrity for any identified well.

(d) The operator shall submit the report required under subsection (c) to the Department at least 30 days prior to the start of drilling the well or at the time the permit application is submitted if the operator plans to start drilling the well less than 30 days from the date of permit issuance. The report shall be provided to the Department electronically through the Department's web site.

(e) The Department may require other information necessary to review the report submitted under subsection (c). The Department may make a determination that additional measures are needed, on a case-by-case basis, to ensure protection of waters of the Commonwealth.

§ 78a.53. Erosion and sediment control and stormwater management.

Any person proposing or conducting earth disturbance activities associated with oil and gas operations shall comply with Chapter 102 (relating to erosion and sediment control). Best management practices for erosion and sediment control and stormwater management for oil and gas operations are listed in the *Erosion and Sediment Pollution Control Program Manual*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 363-2134-008, as amended and updated, the *Pennsylvania Stormwater Best Management Practices Manual*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 363-0300-002, as amended and updated, the *Oil and Gas Operators Manual*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 550-0300-001, as amended and updated, and *Riparian Forest Buffer Guidance*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 395-5600-001, as amended and updated.

§ 78a.54. General requirements.

The well operator shall control and dispose of fluids, residual waste and drill cuttings, including tophole water, brines, drilling fluids, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings, in a manner that prevents pollution of the waters of the Commonwealth and in accordance with §§ 78a.55—78a.58 and 78a.60—78a.63 and with the statutes under which this chapter is promulgated.

§ 78a.55. Control and disposal planning; emergency response for unconventional wells.

(a) *Preparation and implementation of plan for oil and gas operations.* Persons conducting oil and gas operations shall prepare and implement site-specific PPC plans according to §§ 91.34 and 102.5(l) (relating to activities utilizing pollutants; and permit requirements).

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

(c) *Containment practices.* The well operator's PPC plan must describe the containment practices to be

utilized and the area of the well site where primary and secondary containment will be employed as required under § 78a.64a (relating to secondary containment). The PPC plan must include a description of the equipment to be kept onsite during drilling and hydraulic fracturing operations that can be utilized to prevent a spill from leaving the well site.

(d) *Requirements.* The well operator's PPC plan must also identify the control and disposal methods and practices utilized by the well operator and be consistent with the act, The Clean Streams Law (35 P.S. §§ 691.1—691.1001), the Solid Waste Management Act (35 P.S. §§ 6018.101—6018.1003) and §§ 78a.54, 78a.56—78a.58 and 78a.60—78a.61. The PPC plan must also include a pressure barrier policy developed by the operator that identifies barriers to be used during identified operations.

(e) *Revisions.* The well operator shall revise the PPC plan prior to implementing a change to the practices identified in the PPC plan.

(f) *Copies.* A copy of the well operator's PPC plan shall be provided to the Department, the Fish and Boat Commission or the landowner upon request and shall be available at the site during drilling and completion activities for review.

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

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

(i) *Emergency response for unconventional well sites.*

(1) *Applicability.* This subsection applies to unconventional wells.

(2) *Definitions.* For the purposes of this subsection, the following definitions apply:

Access road—A road connecting a well site to the nearest public road, private named road, administrative road with a name and address range, or private unnamed road with an address range.

Address—A location, by reference to a road or a landmark, made by a county or municipality responsible for assigning addresses within its jurisdiction.

Administrative road—A road owned and maintained by the Commonwealth open to the public at the discretion of the Commonwealth that may or may not have a name and address range.

Emergency responder—Police, firefighters, emergency medical technicians, paramedics, emergency management personnel, public health personnel, State certified hazardous materials response teams, Department emergency personnel and other personnel authorized in the course of their occupations or duties, or as an authorized volunteer, to respond to an emergency.

Entrance—The point where the access road to a well site connects to the nearest public road, private named road, administrative road with a name and address range, or a private unnamed road with an address range.

GPS coordinates—The coordinates in latitude and longitude as expressed in degrees decimal to at least six

digits after the decimal point based upon the World Geodetic System 1984 Datum or any other datum approved by the Department.

PEMA—The Pennsylvania Emergency Management Agency.

Private named road—A private road with a name and address range.

Private road—A road that is not a public road.

Private unnamed road—A private road that is not a private named road.

Public road—A road owned and maintained by the Commonwealth, a county within this Commonwealth, a municipality within the Commonwealth or any combination thereof that is open to the public.

Public safety answering point—An entity operating in cooperation with local municipalities and counties to receive 9-1-1 calls for a defined geographic area and process calls according to a specific operational policy.

Well site name—The name used to designate the well site by the operator on the well permit application submitted to the Department.

(3) *Registration of addresses.*

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

(ii) The operator shall determine the GPS coordinates for both the well site and the entrance to the well site. The GPS coordinates must have a horizontal accuracy of plus or minus 6.67 feet or better. If there is more than one well on a well site, one set of GPS coordinates must be used for the well site.

(iii) The operator shall register the following with PEMA, the Department, the Public Safety Answering Point and the county emergency management organization within the county where the well site is located:

(A) The well site name.

(B) The well site address.

(C) The GPS coordinates for the entrance and the well site.

(iv) When there is a change of well site address, the operator shall register the new address as provided in subparagraph (iii).

(v) When there is a change of the entrance due to a change in the well site address or otherwise, the operator shall register the GPS coordinates for the entrance as provided in subparagraph (iii).

(vi) The following shall be retained at the well site for reference when contacting emergency responders:

(A) The well site name.

(B) The well site address.

(C) The GPS coordinates for the entrance and the well site.

(4) *Signage.*

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

(ii) The sign must meet the following requirements:

(A) The sign must be fabricated with approved retroreflective sheeting material meeting ASTM 4956 Type III.

(B) The sign must have a white background with a 2-inch red border and black numbers and letters. Signs for entrances on administrative roads may use other colors provided that the signs use contrasting colors between the background, border, numbers and letters.

(C) The sign must be of sufficient size to accommodate the required information described in this section. The minimum size of a sign must be 36 inches in height and 48 inches in width.

(D) The sign must follow the format of Figure 1 and contain:

(I) The address number for the well site displayed horizontally on the first line of the sign in text no smaller than 4 inches in height.

(II) The full address of the entrance, including the county and municipality in which the entrance is located.

(III) The well operator's company name.

(IV) The 24-hour contact telephone information for the operator of the well site.

(V) The GPS coordinates for the entrance.

(VI) The well site name.

(VII) The wording "In Case of Emergency Call 9-1-1."

(iii) The sign must be mounted independently from other signage.

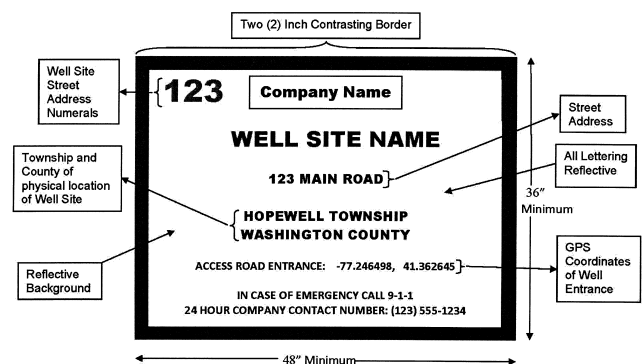
(iv) The bottom of the sign must be positioned a minimum of 3 feet above ground level.

(v) The sign may not contain other markings.

(vi) A sign, as viewed from the applicable road, may not be obstructed from view by vegetation, equipment, vehicles or other obstruction.

(vii) During drilling operations, the American Petroleum Institute (API) permit numbers of the wells at the site may be posted on a nonreflective sign below the principal sign. The API sign may be removed after the well is completed, provided that it is not otherwise required to be posted.

Figure 1. Sample Site Entrance Signage



(Not to scale)

(5) *Emergency response planning.*

(i) The operator of an unconventional well shall develop and implement an emergency response plan that provides for equipment, procedures, training and documentation to properly respond to emergencies that threaten human health and safety for each well site. The plan must incorporate National Incident Management System planning standards, including the use of the Incident Com-

mand System, Incident Action Planning and Common Communications Plans. The plan must include:

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

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

(C) A description of the well site personnel's response to the following well site emergencies:

- (I) Fire.
- (II) Medical emergency.
- (III) Explosion or similar event.
- (IV) Spill.
- (V) Security breach or other security event.

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

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

(I) The current Safety Data Sheet (SDS) required under law to be present at the well site.

(II) The location of the SDSs at the well site.

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

(E) A list containing the location of any fire suppression and spill control equipment maintained by the well operator at the well site.

(F) A description of any emergency equipment available to the operator that is located off of the well site.

(G) A summary of the risks and hazards to the public within 1/2 mile of the well site and the associated planning assumptions.

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

(I) The location of and monitoring plan for any emergency shutoff valves located along well development pipelines in accordance with § 78a.68b (relating to well development pipelines for oil and gas operations).

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

(A) A base plan common to all of the operator's well sites containing some of the elements described in subparagraph (i).

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

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

(iv) The operator shall review the plan and submit an update annually on or before March 1 each year. In the event that updates are not made to the plan for that review period, the operator shall submit a statement indicating the review was completed and updates to the plan were not necessary.

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

- (A) PEMA.
- (B) The Department.
- (C) The county emergency management agency.

(D) The Public Safety Answering Point with jurisdiction over the well site.

(vi) A copy of the plan shall be available at the well site during all phases of operation.

(vii) The emergency response plan must address response actions for the following stages of operation at the well site:

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

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

(6) *Transition.*

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

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

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

§ 78a.56. Temporary storage.

(a) Except as provided in §§ 78a.60(b) and 78a.61(b) (relating to discharge requirements; and disposal of drill cuttings), the operator shall contain regulated substances and wastes used at or generated at a well site in a tank, series of tanks or other storage structures approved by the Department. The operator shall install or construct and maintain the tank or series of tanks or other approved storage structures in accordance with the following requirements:

(1) The tank, series of tanks or other approved storage structure shall be constructed and maintained with sufficient capacity to contain all regulated substances which are used or produced during drilling, altering, completing, recompleting, servicing and plugging the well.

(2) Modular aboveground storage structures that exceed 20,000 gallons capacity may not be utilized to store regulated substances without prior Department approval. The Department will maintain a list of approved modular storage structures on its web site.

(3) The operator shall obtain siting approval from the Department for site-specific installation of all modular aboveground storage structures for each individual well site where use of the modular aboveground storage structure is proposed.

(4) After obtaining approval to utilize a modular aboveground storage structure at a specific well site, the owner or operator shall notify the Department at least 3 business days before the beginning of construction of these storage structures. The notice shall be submitted electronically to the Department through its web site and include the date the storage structure installation will begin. If the date of installation is extended, the operator shall renotify the Department with the date that the installation will begin, which does not need to be 3 business days in advance.

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

(6) Tanks and other approved storage structures shall be designed, constructed and maintained to be structurally sound and reasonably protected from unauthorized acts of third parties.

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

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

(9) A tank or other approved storage structure that contains drill cuttings from below the casing seat, regulated substances or fluids other than topsoil water, fresh water and uncontaminated drill cuttings shall be impermeable.

(10) Condensate, whether separated or mixed with other fluids at a concentration greater than 1% by volume, may not be stored in any open top structure or pit. Aboveground tanks used for storing or separating condensate during well completion shall be monitored and have controls to prevent vapors from exceeding the L.E.L. of the condensate outside the tank. Tanks used for storing or separating condensate must be grounded.

(b) The operator may request to use practices other than those specified in subsection (a) which provide equivalent or superior protection by submitting a request to the Department for approval. The request shall be made electronically to the Department through its web site on forms provided by the Department.

(c) Disposal of uncontaminated drill cuttings in a pit or by land application shall comply with § 78a.61.

(d) Pits may not be used for temporary storage. An operator using a pit for temporary storage as of October 8, 2016, shall properly close the pit in accordance with appropriate restoration standards no later than April 8, 2017. Any spills or leaks detected shall be reported and

remediated in accordance with § 78a.66 (relating to reporting and remediating spills and releases) prior to pit closure.

§ 78a.57. Control, storage and disposal of production fluids.

(a) Unless a permit has been obtained under § 78a.60(a) (relating to discharge requirements), the operator shall collect the brine and other fluids produced during operation of the well in a tank or a series of tanks, or other device approved by the Department for subsequent disposal or reuse. Open top structures may not be used to store brine and other fluids produced during operation of the well. An operator using a pit for storage of production fluids as of October 8, 2016, shall report the use of the pit to the Department no later than April 8, 2017, and shall properly close the pit in accordance with appropriate restoration standards no later than October 10, 2017. Any spills or leaks detected shall be reported and remediated in accordance with § 78a.66 (relating to reporting and remediating spills and releases) prior to pit closure. Except as allowed in this subchapter or otherwise approved by the Department, the operator may not discharge the brine and other fluids on or into the ground or into the waters of the Commonwealth. Unless separately permitted under the Solid Waste Management Act (35 P.S. §§ 6018.101—6018.1003), wastes may not be stored at a well site unless the wastes are generated at or will be beneficially reused at that well site.

(b) An operator may not use a pit for the control, handling or storage of brine and other fluids produced during operation of a well.

(c) Secondary containment is required for all new, refurbished or replaced aboveground primary containment, including their associated manifolds, that contain brine and other fluids produced during operation of the well. If one tank in a series of tanks is added, refurbished or replaced, secondary containment is required for the entire series of tanks. The secondary containment area provided by dikes or other methods of secondary containment open to the atmosphere must have containment capacity sufficient to hold the volume of the largest single aboveground tank, plus an additional 10% of volume for precipitation. Compliance with § 78a.64 (relating to secondary containment around oil and condensate tanks) or using double walled tanks capable of detecting a leak in the primary containment fulfills the requirements in this subsection.

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

(e) Underground or partially buried storage tanks used to store brine or other fluids produced during operation of the well shall be designed, constructed and maintained to be structurally sound in accordance with sound engineering practices adhering to Nationally recognized industry standards and the manufacturer's specifications. A well operator utilizing underground or partially buried storage tanks as of October 8, 2016, shall provide electronically to the Department a list of the well sites through its web site where the underground or partially buried storage tanks are located by April 8, 2017. A well operator shall register the location of an additional underground storage

tank prior to installation. Registration shall utilize forms provided by the Department and be submitted electronically to the Department through its web site.

(f) All new, refurbished or replaced aboveground storage tanks that store brine or other fluid produced during operation of the well must comply with the corrosion control requirements in §§ 245.531—245.534 (relating to corrosion and deterioration prevention), with the exception of use of Department-certified inspectors to inspect interior linings or coatings.

(g) All new, refurbished or replaced underground storage tanks that store brine or other fluid produced during operation of the well must comply with the corrosion control requirements in § 245.432 (relating to operation and maintenance including corrosion protection) with the exception of use of Department-certified inspectors to inspect interior linings.

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

(i) Tanks storing brine or other fluids produced during operation of the well shall be inspected by the operator at least once per calendar month and documented. Deficiencies noted during the inspection shall be addressed and remedied. When substantial modifications are necessary to correct deficiencies, they shall be made in accordance with manufacturer's specifications and applicable engineering design criteria. Any deficiencies identified during the inspection shall be reported to the Department electronically through its web site within 3 days of the inspection and remedied prior to continued use of the tank. Inspection records shall be maintained for 1 year and made available to the Department upon request.

§ 78a.58. Onsite processing.

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

(b) Approval from the Department is not required for the following activities conducted at a well site:

- (1) Mixing fluids with freshwater.
- (2) Aerating fluids.
- (3) Filtering solids from fluids.

(c) Activities described in subsection (b) shall be conducted within secondary containment.

(d) An operator processing fluids or drill cuttings generated by the development, drilling, stimulation, alteration, operation or plugging of oil or gas wells shall develop an action plan specifying procedures for monitoring for and responding to radioactive material produced by the treatment processes, as well as related procedures for training, notification, recordkeeping and reporting. The action plan shall be prepared in accordance with the Department's *Guidance Document on Radioactivity Moni-*

toring at Solid Waste Processing and Disposal Facilities, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 250-3100-001, as amended and updated, or in a manner at least as protective of the environment, facility staff and public health and safety and which meets all statutory and regulatory requirements.

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

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

(g) Processing of fluids in a manner approved under subsection (a) will be deemed to be approved at subsequent well sites provided the operator notifies the Department of location of the well site where the processing will occur at least 3 business days prior to the beginning of processing operations. The notice shall be submitted electronically to the Department through its web site and include the date activities will begin.

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

§ 78a.59a. Impoundment embankments.

(a) Embankments constructed for well development impoundments for oil and gas operations must meet the following requirements:

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

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

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

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

(5) Soils to be used for embankment construction must be classified in accordance with ASTM D-2487 (Unified Soils Classification). Soil samples must be classified at a minimum rate of one sample per 10,000 cubic yards of placed fill with at least one test per source with an additional test conducted each time the material changes. At least one sample must be classified in accordance with ASTM D-2487. Soils utilized during embankment construction shall be described and identified in accordance with ASTM D-2488—09A (Standard Practice for Description and Identification of Soils (Visual-Manual Procedure)). Soil identification and description in accordance

with this procedure shall be performed at a minimum rate of one sample per 1,000 cubic yards of placed fill. Results of testing of materials shall be provided to the Department upon request.

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

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

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

(i) Compaction shall be conducted with a sheepfoot or pad roller.

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

(iii) Soil shall be compacted until visible nonmovement of the embankment material.

(iv) Soil shall be compacted to a minimum of 95% of the standard proctor in accordance with ASTM D698 (Standard Test Methods for Laboratory Compaction Characteristics of Soil Using Standard Effort). Satisfactory compaction shall be verified by field density testing in accordance with ASTM D1556 (Standard Test Method for Density and Unit Weight of Soil in Place by the Sand Cone Method) or ASTM D6938 (Standard Test Method for In-Place Density and Water Content of Soil and Soil-Aggregate by Nuclear Methods (Shallow Depth)) with a minimum of one test per 2,000 square yards of lift surface and at least one test per lift.

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

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

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

(b) The owner or operator may request approval from the Department to deviate from the requirements in this section. The request must demonstrate that the alternate practice provides equivalent or superior protection to the requirements of this section.

§ 78a.59b. Well development impoundments.

(a) In addition to meeting the requirements of § 78a.59a (relating to impoundment embankments), any new well development impoundments must be in compliance with this section.

(b) A well operator using a well development impoundment prior to October 8, 2016, shall register the location of the well development impoundment by December 7, 2016, by providing the Department, through the Department's web site, with electronic notification of the GPS coordinates, township and county where the well development impoundment is located as well as certification as to whether the impoundment meets the requirements in

subsections (d), (e) and (h). Any impoundments that do not comply with the requirements in subsections (d), (e) and (h) shall be upgraded to meet these requirements or restored in accordance with subsection (g) by October 10, 2017.

(c) A well operator shall register the location of a new well development impoundment prior to construction. Registration of the well development impoundment may be transferred to another operator. Registration transfers shall utilize forms provided by the Department and be submitted electronically to the Department through its web site.

(d) Well development impoundments shall be constructed with a synthetic impervious liner.

(e) Unless an individual is continuously present at a well development impoundment, a fence must completely surround the well development impoundment to prevent unauthorized acts of third parties and damage caused by wildlife.

(f) The bottom of the impoundment must be at least 20 inches above the seasonal high groundwater table. The applicant may maintain the required separation distance of 20 inches by passive artificial means such as an under-drain system throughout the lifetime of the impoundment. In no case shall the regional groundwater table be affected by the passive artificial system. The operator shall document the depth of the seasonal high groundwater table, the manner in which the depth of the seasonal high groundwater table was ascertained, the distance between the bottom of the impoundment and the seasonal high groundwater table, and the depth of the regional groundwater table if the separation between the impoundment bottom and seasonal high groundwater table is maintained by artificial means. A soil scientist or other similarly trained person using accepted and documented scientific methods shall make the determination. The determination must contain a statement certifying that the impoundment bottom is at least 20 inches above the seasonal high groundwater table according to observed field conditions. The name, qualifications and statement of the person making the determination and the basis of the determination shall be provided to the Department upon request.

(g) Well development impoundments shall be restored by the operator that the impoundment is registered to within 9 months of completion of hydraulic fracturing of the last well serviced by the impoundment. An impoundment is restored under this subsection by the operator removing excess water and the synthetic liner, returning the site to approximate original conditions, including preconstruction contours, and supporting the land uses that existed prior to oil and gas operations to the extent practicable. An extension of the restoration requirement may be approved under § 78a.65(c) (relating to site restoration). If requested by the landowner in writing, on forms provided by the Department, the requirement to return the site to approximate original contours may be waived by the Department if the liner is removed from the impoundment.

(h) Prior to storing mine influenced water in a well development impoundment, the operator shall develop a mine influenced water storage plan and submit it to the Department for approval.

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

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

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

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

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

(i) The Department may require the operator to test water sources proposed to be stored in a well development impoundment prior to storage.

§ 78a.59c. Centralized impoundments.

(a) An operator using a centralized impoundment as of October 8, 2016, shall close the centralized impoundment in accordance with this section or obtain a permit in accordance with Subpart D, Article IX (relating to residual waste management). The closure plan shall be submitted electronically to the Department through its web site for review and approval no later than April 8, 2017. The operator shall properly close the centralized impoundment in accordance with the approved plan or obtain a permit in accordance with Subpart D, Article IX no later than October 8, 2019.

(b) The closure plan must provide for the following:

(1) Removal of any impermeable membrane, concrete and earthen liner so that water movement to subsoils is achieved.

(2) Restoration of the site to approximate original conditions, including preconstruction contours, and back-filling the impoundment to above finished grade to allow for settlement of fill and so the impoundment will no longer impound water.

(3) A plan for the removal of equipment, structures, wastes and related material from the facility.

(4) An estimate of when final closure will occur, including an explanation of the basis for the estimate.

(5) A description of the steps necessary for closure of the facility.

(6) A narrative description, including a schedule of measures that are proposed to be carried out in preparation for closure and after closure at the facility, including measures relating to the following:

(i) Water quality monitoring including, but not limited to, analyses of samples from the monitoring wells that were installed at the time of the construction of the centralized impoundment.

(ii) A soil sampling plan that explains how the operator will analyze the soil beneath the impoundment's liners. Analysis shall be based on a grid pattern or other method approved by the Department. Any spills or leaks detected shall be reported and remediated in accordance with § 78a.66 (relating to reporting and remediating spills and releases) prior to impoundment closure.

(iii) Compliance with Chapter 102 (relating to erosion and sediment control) including erosion and sediment control and PCSM.

(iv) Access control, including maintenance of access control.

(v) The name, address and telephone number at which the operator may be reached.

§ 78a.60. Discharge requirements.

(a) The owner and operator may not cause or allow a discharge of a substance, fill or dredged material to the waters of the Commonwealth unless the discharge complies with this subchapter and Chapters 91, 92a, 93, 95, 102 and 105, The Clean Streams Law (35 P.S. §§ 691.1—691.1001), the Dam Safety and Encroachments Act (32 P.S. §§ 693.1—693.27) and the act.

(b) The owner and operator may not discharge top hole water or water in a pit as a result of precipitation by land application unless the discharge is in accordance with the following requirements:

(1) No additives, drilling muds, regulated substances or drilling fluids other than gases or fresh water have been added to or are contained in the water, unless otherwise approved by the Department.

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

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

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

(5) The discharge water shall be spread over an undisturbed, vegetated area capable of absorbing the top hole water and filtering solids in the discharge, and spread in a manner that prevents a direct discharge to surface waters and complies with § 78a.53 (relating to erosion and sediment control and stormwater management).

(6) Upon completion, the area complies with § 78a.53.

(7) The area of land application is not within 200 feet of a water supply or within 100 feet of a watercourse or body of water or within the floodplain.

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

(c) Compliance with subsection (b) shall be documented by the operator and made available to the Department upon request while conducting activities under subsection (b) and submitted under § 78a.65(e)(1) and (2) (relating to site restoration).

§ 78a.61. Disposal of drill cuttings.

(a) *Drill cuttings from above the surface casing seat—pits.* The owner or operator may dispose of drill cuttings from above the surface casing seat determined in accordance with § 78a.83(c) (relating to surface and coal protective casing and cementing procedures) in a pit at the well site if the owner or operator satisfies the following requirements:

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

(2) The drill cuttings are not contaminated with a regulated substance, including brines, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids, or drilling fluids other than top hole water, fresh water or gases.

(3) The disposal area is not within 100 feet of a watercourse or body of water or within the floodplain.

(4) The disposal area is not within 200 feet of a water supply.

(5) The pit is designed, constructed and maintained to be structurally sound.

(6) The free liquid fraction of the waste shall be removed and disposed under § 78a.60 (relating to discharge requirements).

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

(8) The surface of the backfilled pit area shall be revegetated to stabilize the soil surface and comply with § 78a.53 (relating to erosion and sediment control and stormwater management). The revegetation shall establish a diverse, effective, permanent, vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface of the landowner, the surface shall be stabilized against erosion.

(b) *Drill cuttings from above the surface casing seat—land application.* The owner or operator may dispose of drill cuttings from above the surface casing seat determined in accordance with § 78a.83(c) by land application at the well site if the owner or operator satisfies the following requirements:

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

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

(3) The disposal area is not within 100 feet of a watercourse or body of water or within the floodplain.

(4) The disposal area is not within 200 feet of a water supply.

(5) The soils have a minimum depth from surface to bedrock of 20 inches.

(6) The drill cuttings are not spread when saturated, snow covered or frozen ground interferes with incorporation of the drill cuttings into the soil.

(7) The drill cuttings are not applied in quantities which will result in runoff or in surface water or ground-water pollution.

(8) The free liquid fraction is disposed in accordance with § 78a.60.

(9) The drill cuttings are spread and incorporated into the soil. The loading and application rate of drill cuttings may not exceed a maximum of drill cuttings to soil ratio of 1:1.

(10) The land application area shall be revegetated to stabilize the soil surface and comply with § 78a.53. The revegetation shall establish a diverse, effective permanent vegetative cover which is capable of self-regeneration and plant succession. Where vegetation would interfere with the intended use of the surface by the landowner, the surface shall be stabilized against erosion.

(c) *Drill cuttings from below the surface casing seat.* After removal of the free liquid fraction and disposal in accordance with § 78a.60, drill cuttings from below the surface casing seat determined in accordance with § 78a.83(c) may not be disposed of on the well site unless authorized by a permit or other approval is obtained from the Department in accordance with § 78a.62 or § 78a.63

(relating to disposal of residual waste—pits; and disposal of residual waste—land application).

(d) *Alternative practices.* The owner or operator may request to use solidifiers, dusting, unlined pits, attenuation or other alternative practices for the disposal of uncontaminated drill cuttings by submitting a request to the Department for approval. The request shall be made on forms provided by the Department and shall demonstrate that the practice provides equivalent or superior protection to the requirements of this section. The Department will maintain a list of approved solidifiers on its web site. The operator does not need to request approval from the Department for use of approved solidifiers.

(e) *Notifications.* The owner or operator shall notify the Department at least 3 business days before disposing of drill cuttings under this section. This notice shall be submitted electronically to the Department through its web site and include the date the cuttings will be disposed. If the date of disposal is extended, the operator shall renotify the Department of the date of disposal, which does not need to be 3 business days in advance. The owner or operator shall also provide notice of disposal to the surface landowner, including the location of the disposed drill cuttings, within 10 business days of completion of disposal.

§ 78a.62. Disposal of residual waste—pits.

An owner or operator proposing to dispose of residual waste, including contaminated drill cuttings, in a pit at the well site shall obtain a residual waste pit disposal permit issued under this chapter prior to constructing the waste disposal pit.

§ 78a.63. Disposal of residual waste—land application.

An owner or operator proposing disposal of residual waste, including contaminated drill cuttings, at the well site by land application shall obtain a residual waste land application permit issued under this chapter prior to land application of the waste.

§ 78a.63a. Alternative waste management.

An operator seeking to manage waste on a well site in any manner other than provided in §§ 78a.56—78a.58, 78a.59a, 78a.59b, 78a.59c and 78a.60—78a.63 shall submit a request electronically to the Department through its web site describing the alternate management practice and shall demonstrate that the practice provides equivalent or superior protection to the requirements in these sections.

§ 78a.64. Secondary containment around oil and condensate tanks.

(a) If an owner or operator uses a tank or tanks with a combined capacity of at least 1,320 gallons to contain oil or condensate produced from a well, the owner or operator shall construct and maintain a dike or other method of secondary containment which satisfies the requirements under 40 CFR Part 112 (relating to oil pollution prevention) around the tank or tanks which will prevent the tank contents from entering waters of the Commonwealth.

(b) The secondary containment provided by the dikes or other method of secondary containment must have containment capacity sufficient to hold the volume of the largest single tank, plus a reasonable allowance for precipitation based on local weather conditions and facility operation.

(c) Prior to drainage of accumulated precipitation from secondary containment, the secondary containment shall be inspected and accumulations of oil picked up and returned to the tank or disposed of in accordance with approved methods.

(d) After complying with subsection (c), drainage of secondary containment is acceptable if:

(1) The accumulation in the secondary containment consists of only precipitation directly to the secondary containment and drainage will not cause a harmful discharge or result in a sheen.

(2) The secondary containment drain valve is opened and resealed, or other drainage procedure, as applicable, is conducted under responsible supervision.

(e) An owner or operator who installed a tank or tanks with a combined capacity of at least 1,320 gallons prior to October 8, 2016, to store condensate produced from a well shall meet the requirements of this section when a tank is replaced, refurbished or repaired or by October 9, 2018, whichever is sooner.

§ 78a.64a. Secondary containment.

(a) Well sites shall be designed and constructed using secondary containment.

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

(c) Secondary containment must meet all of the following:

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

(2) Secondary containment must have a coefficient of permeability no greater than 1×10^{-10} cm/sec.

(3) The physical and chemical characteristics of all liners, coatings or other materials used as part of the secondary containment, that could potentially come into direct contact with regulated substances being stored, must be compatible with the regulated substance and be resistant to physical, chemical and other failure during handling, installation and use. Liner compatibility must satisfy compatibility test methods as approved by the Department.

(d) Methods of secondary containment open to the atmosphere must have storage capacity sufficient to hold the volume of the largest single aboveground primary containment, plus an additional 10% of volume for precipitation. Using double walled tanks capable of detecting a leak in the primary containment fulfill the requirements in this subsection. Tanks that are manifolded together shall be designed in a manner to prevent the uncontrolled discharge of multiple manifolded tanks.

(e) All secondary containment shall be inspected weekly to ensure integrity. If the secondary containment is damaged or compromised, the well operator shall repair the secondary containment as soon as practicable. The well operator shall maintain records of any repairs until the well site is restored. Stormwater shall be

removed as soon as possible and prior to the capacity of secondary containment being reduced by 10% or more.

(f) Regulated substances that escape from primary containment or are otherwise spilled onto secondary containment shall be removed as soon as possible. After removal of the regulated substances the operator shall inspect the secondary containment. If the secondary containment did not completely contain the material, the operator shall notify the Department and remediate the affected area in accordance with § 78a.66 (relating to reporting and remediating spills and releases).

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

(h) Inspection reports and maintenance records shall be available at the well site for review by the Department.

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

§ 78a.65. Site restoration.

(a) *Restoration.* The owner or operator shall restore land surface areas disturbed to construct the well site as follows:

(1) *Post-drilling.* Within 9 months after completion of drilling a well, the owner or operator shall undertake post-drilling restoration of the well site in accordance with a restoration plan developed in accordance with subsection (b) and remove all drilling supplies, equipment, primary containment and secondary containment not necessary for production or needed to safely operate the well.

(i) When multiple wells are drilled or permitted to be drilled on a single well site, post-drilling restoration is required within 9 months after completion of drilling all permitted wells on the well site or 9 months after the expiration of all existing well permits on the well site, whichever is later.

(ii) A drill hole or bore hole used to facilitate the drilling of a well shall be filled with cement, soil, uncontaminated drill cuttings or other earthen material before moving the drilling equipment from the well site.

(iii) Drilling supplies and equipment not needed for production may only be stored on the well site if express written consent of the surface landowner is obtained and the supplies or equipment are maintained in accordance with § 78a.64a (relating to secondary containment).

(iv) The areas necessary to safely operate the well include the following:

(A) Areas used for service vehicle and rig access.

(B) Areas used for storage tanks and secondary containment.

(C) Areas used for wellheads and appurtenant oil and gas processing facilities.

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

(E) Areas used to store any supplies or equipment consented to by the surface landowner.

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

(2) *Post-plugging.* Within 9 months after plugging the final well on the well site, the owner or operator shall remove all production or storage facilities, supplies and equipment and restore the well site to approximate original conditions and restore stormwater runoff rate, volume and quality to preconstruction condition in accordance with § 102.8 (relating to PCSM requirements).

(3) *Wells not drilled.* If a well site is constructed and the well is not drilled, the well site shall be restored within 9 months after the expiration of the well permit unless the Department approves an extension for reasons of adverse weather or lack of essential fuel, equipment or labor.

(b) *Restoration plan.* An operator of a well site shall develop and implement a restoration plan. The restoration plan must address:

(1) The restoration of areas not needed to safely operate the well to approximate original conditions.

(2) The proposed site configuration after post-drilling restoration including the areas of the well site being restored.

(3) The minimization of impervious areas. Impervious areas include, but are not limited to, areas where soil has been compacted, areas where soil has been treated with amendments to firm or harden the soil, and areas underlain with an impermeable liner.

(4) The removal of all drilling supplies and equipment not needed for production, including primary and secondary containment.

(5) The manner in which the restoration of the disturbed areas will achieve meadow in good condition or better or otherwise incorporate ABACT or nondischarge alternative PCSM best management practices (BMP).

(6) PCSM BMPs remaining in place and proof of compliance with § 102.8(l) and (m), or a licensed professional certification of complete site restoration to approximate original contours and return to preconstruction stormwater runoff rate, volume and quality in accordance with § 102.8(g). The owner or operator shall remain responsible for compliance with the terms of the restoration plan including long-term operation and maintenance of all PCSM BMPs on the project site and is responsible for any violations occurring on the project site, prior to written approval of the final restoration report.

(7) The permanent stabilization of the restored areas by either of the following:

(i) In accordance with § 102.22 (relating to site stabilization).

(ii) Through implementation of PCSM BMPs as required under § 102.8, including § 102.8(a)—(m).

(8) An operator of a well site who is required to obtain a permit under § 102.5(c) (relating to permit requirements) may develop a written restoration plan containing drawings and a narrative that address the requirements of paragraphs (1)—(7) to demonstrate compliance with § 102.8(n).

(c) *Extension of drilling or production period.* The restoration period in this subsection may be extended through approval by the Department for an additional period of time, not to exceed 2 years.

(1) A request to extend the restoration period shall be submitted electronically on forms provided by the Department through the Department's web site not more than 6 months after the completion of drilling.

(2) The request must specify the reasons for the request to extend the restoration period not to exceed 24 months. The request must include a justification for the length of extension and demonstrate that either:

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

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

(3) A demonstration that the extension will result in less earth disturbance, increased water reuse or more efficient development of the resources must include the following:

(i) A demonstration that the site is stabilized and the BMPs utilized on the well site will address PCSM.

(ii) A demonstration that the portions of the well site not occupied by production facilities or equipment will be returned to approximate original conditions.

(d) *Areas not restored.* Disturbed areas associated with well sites that are not included in a restoration plan, and other remaining impervious surfaces, must comply with all requirements in Chapter 102 (relating to erosion and sediment control). The PCSM plan provisions in § 102.8(n) apply only to the portions of the restoration plan that provide for restoration of disturbed areas to meadow in good condition or better or otherwise incorporate ABACT or nondischarge PCSM BMPs.

(e) *Post-drilling restoration reports.* Within 60 calendar days after post-drilling restoration under subsection (a)(1), the operator shall submit a restoration report to the Department. The well operator shall forward a copy of all restoration reports to the surface landowner. The report shall be made electronically on forms provided by the Department through the Department's web site and must identify the following:

(1) The date of land application of the topsoil water.

(2) The results of pH and specific conductance tests and an estimated volume of discharge.

(3) The method used for disposal or reuse of the free liquid fraction of the waste, and the name of the hauler and disposal facility, if any.

(4) The location, including GPS coordinates, of the pit in relation to the well, the depth of the pit, the type and thickness of the material used for the pit subbase, the type and thickness of the pit liner, the type and nature of the waste, the type of any approved solidifier, a description of the pit closure procedures used and the pit dimensions.

(5) The location of the area used for land application of the waste, and the results of a chemical analysis of the waste soil mixture if requested by the Department.

(6) The types and volumes of waste produced and the name and address of the waste disposal facility and waste hauler used to dispose of the waste.

(7) The name, qualifications and basis for determination that the bottom of a pit used for encapsulation is at least 20 inches above the seasonal high groundwater table.

(f) *Post-plugging restoration reports.* Within 60 calendar days after post-plugging restoration under subsection (a)(2), the operator shall submit a restoration report to the Department. The well operator shall forward a copy of all restoration reports to the surface landowner. The

report shall be made electronically on forms provided by the Department through the Department's web site and must include the following:

(1) A description of the types and volumes of waste produced, and the name and address of the waste disposal facility and waste hauler used to dispose of the waste.

(2) Confirmation that earth disturbance activities, site restoration including an installation of any PCSM BMPs and permanent stabilization in accordance with § 102.22 have been completed.

(g) *Written consent.* Written consent of the landowner on forms provided by the Department satisfies the restoration requirements of this section provided the operator develops and implements a site restoration plan that complies with subsections (a) and (b)(2)–(7) and all PCSM requirements in Chapter 102.

§ 78a.66. Reporting and remediating spills and releases.

(a) *Scope.* This section applies to reporting and remediating spills or releases of regulated substances on or adjacent to well sites and access roads.

(b) *Reporting releases.*

(1) An operator or other responsible party shall report the following spills and releases of regulated substances to the Department in accordance with paragraph (2):

(i) A spill or release of a regulated substance causing or threatening pollution of the waters of the Commonwealth in the manner required under § 91.33 (relating to incidents causing or threatening pollution).

(ii) A spill or release of 5 gallons or more of a regulated substance over a 24-hour period that is not completely contained by secondary containment.

(2) In addition to meeting the notification requirements of § 91.33, the operator or other responsible party shall contact the appropriate regional Department office by telephone or call the Department's Statewide toll free number as soon as practicable, but no later than 2 hours after discovering the spill or release. To the extent known, the following information shall be provided:

(i) The name of the person reporting the spill or release and telephone number where that person can be reached.

(ii) The name, address and telephone number of the operator or other responsible party.

(iii) The date and time of the spill or release or when it was discovered.

(iv) The location of the spill or release, including directions to the site, GPS coordinates or the 9-1-1 address, if available.

(v) A brief description of the nature of the spill or release and its cause, what potential impacts to public health and safety or the environment may exist, including any available information concerning the pollution or threatened pollution of surface water, groundwater or soil.

(vi) The estimated weight or volume of each regulated substance spilled or released.

(vii) The nature of any injuries.

(viii) Remedial actions planned, initiated or completed.

(3) The operator or other responsible party shall take necessary interim corrective actions to prevent:

(i) The regulated substance from polluting or threatening to pollute the waters of the Commonwealth.

(ii) Damage to property.

(iii) Impacts to downstream users of waters of the Commonwealth.

(4) The operator or other responsible party shall identify and sample water supplies that have been polluted or for which there is a potential for pollution in a reasonable and systematic manner. The operator or other responsible party shall restore or replace a polluted water supply in accordance with § 78a.51 (relating to protection of water supplies). The operator or other responsible party shall provide a copy of the sample results to the water supply owner and the Department within 5 business days of receipt of the sample results from the laboratory.

(5) The Department may immediately approve temporary emergency storage or transportation methods necessary to prevent or mitigate harm to the public health, safety or the environment. Storage may be at the site of the incident or at a site approved by the Department.

(6) After responding to a spill or release, the operator or other responsible party shall decontaminate equipment used to handle the regulated substance, including storage containers, processing equipment, trucks and loaders, before returning the equipment to service. Contaminated wash water, waste solutions and residues generated from washing or decontaminating equipment shall be managed as residual waste.

(c) *Remediating releases.* Remediation of an area polluted by a spill or release is required. The operator or other responsible party shall remediate a release in accordance with the following:

(1) Spills or releases to the ground of less than 42 gallons at a well site that do not pollute or threaten to pollute waters of the Commonwealth may be remediated by removing the soil visibly impacted by the spill or release and properly managing the impacted soil in accordance with the Department's waste management regulations. The operator or responsible party shall notify the Department of its intent to remediate a spill or release in accordance with this paragraph at the time the report of the spill or release is made.

(2) For spills or releases to the ground of greater than or equal to 42 gallons or that pollute or threaten to pollute waters of the Commonwealth, the operator or other responsible person must demonstrate attainment of one or more of the standards established by Act 2 and Chapter 250 (relating to administration of Land Recycling Program) in the following manner:

(i) Within 15 business days of the spill or release, the operator or other responsible party shall provide an initial written report that includes, to the extent that the information is available, the following:

(A) The regulated substance involved.

(B) The location where the spill or release occurred.

(C) The environmental media affected.

(D) Pollution or threatened pollution of water supplies.

(E) Impacts to buildings or utilities.

(F) Interim remedial actions planned, initiated or completed.

(G) A summary of the actions the operator or other responsible party intends to take at the site to address the spill or release such as a schedule for site character-

ization, to the extent known, and the anticipated time frames within which it expects to take those actions.

(ii) After the initial report, any new pollution or other impacts identified or discovered during interim remedial actions or site characterization shall also be reported in writing to the Department within 15 business days of their discovery.

(iii) Within 180 calendar days of the spill or release, the operator or other responsible party shall perform a site characterization to determine the extent and magnitude of the pollution and submit a site characterization report to the appropriate Department regional office describing the findings. The time to submit the site characterization report may be extended by the Department. The report must include a description of any interim remedial actions taken.

(iv) The report under subparagraph (iii) may be considered to be a final remedial action completion report if the interim remedial actions meet all of the requirements of an Act 2 cleanup standard.

(v) If the site characterization indicates that the interim remedial actions taken did not adequately remediate the spill or release, the operator or other responsible party shall develop and submit a remedial action plan to the appropriate Department regional office for approval. The plan is due within 45 calendar days of submission of the site characterization to the Department. Remedial action plans must contain the elements outlined in § 245.311(a) (relating to remedial action plan), as well as a schedule for the submission of remedial action progress reports.

(vi) Within 45 days after the selected remediation standard has been attained, the operator or other responsible party shall submit a remedial action completion report to the appropriate Department regional office for approval. Remedial action completion reports shall contain the elements outlined in § 245.313(b) (relating to remedial action completion report).

§ 78a.67. Borrow pits.

(a) An operator who owns or controls a borrow pit that does not require a permit under the Noncoal Surface Mining Conservation and Reclamation Act (52 P.S. §§ 3301—3326) under the exemption in section 3273.1(b) of the act (relating to relationship to solid waste and surface mining), because the borrow pit is used exclusively for extraction of minerals for the purpose of oil and gas well development, including access road construction, shall operate, maintain and reclaim the borrow pit in accordance with the performance standards in Chapter 77, Subchapter I (relating to environmental protection performance standards) and in accordance with Chapter 102 (relating to erosion and sediment control), and other applicable laws. The mining permit exemption only applies so long as the borrow pit is servicing an oil and gas well site where a well is permitted under section 3211 of the act (relating to well permits) or registered under section 3213 of the act (relating to well registration and identification) and the requirements of section 3225 of the act (relating to bonding) are satisfied by filing a surety or collateral bond for wells drilled on or after April 18, 1985. Borrow pits shall be subject to The Clean Streams Law (35 P.S. §§ 691.1—691.1001), and regulations promulgated thereunder, including Chapter 102. For purposes of determining permitting requirements under § 102.5(c) (relating to permit requirements), areas subject to the mining permit exemption shall be considered part of the project along with the well site being serviced.

(b) Operators shall register the location of their existing borrow pits by December 7, 2016, by providing the Department, electronically, through the Department's web site, with the GPS coordinates, township and county where the borrow pit is located. The operator shall register the location of a new borrow pit in the same manner prior to construction.

(c) Borrow pits used for the development of oil and gas well sites and access roads that no longer meet the conditions under section 3273.1 of the act must meet one of the following:

(1) Be restored within 9 months after completion of drilling the final well on a well site serviced by the borrow pit or 9 months after the expiration of all well permits on well sites serviced by the borrow pit, whichever occurs later. An extension of the restoration requirement may be approved under § 78a.65(c) (relating to site restoration).

(2) Obtain a noncoal surface mining permit for its continued use, unless relevant exemptions apply under the Noncoal Surface Mining Conservation and Reclamation Act and regulations promulgated thereunder.

(d) A well operator who owns or operates a borrow pit constructed prior to October 8, 2016, shall have the borrow pit inspected by a qualified person for compliance with the requirements of this section prior to April 6, 2017. Any borrow pits that do not comply with subsection (a) shall be upgraded to meet the requirements of this section or restored by October 10, 2017.

§ 78a.68. Oil and gas gathering pipelines.

(a) The requirements of this section apply to all earth disturbance activities associated with oil and gas gathering pipeline installations and supporting facilities including the construction right-of-way, work space areas, pipe storage yards, borrow and disposal areas, access roads and other necessary areas identified on the erosion and sediment control plan. The construction, installation, use, maintenance, repair and removal of oil and gas gathering pipelines under this section shall be conducted in accordance with Chapters 102 and 105 (relating to erosion and sediment control; and dam safety and waterway management).

(b) Highly visible flagging, markers or signs shall be used to identify the shared boundaries of the limit of disturbance, wetlands and locations of threatened or endangered species habitat prior to land clearing. The flagging, markers or signs shall be maintained throughout earth disturbance activities and restoration or PCSM activities.

(c) The operator shall maintain topsoil and subsoil during excavation under the following, unless otherwise authorized by the Department:

(1) Topsoil and subsoil must remain segregated until restoration.

(2) Topsoil and subsoil must be prevented from entering watercourses and bodies of water.

(3) Topsoil cannot be used as bedding for pipelines.

(4) Native topsoil and imported topsoil must be of equal or greater quality to ensure the land is capable of supporting the uses that existed prior to earth disturbance.

(d) Backfilling of the gathering pipeline trench shall be conducted in a manner that minimizes soil compaction at the surface to ensure that water infiltration will be

sufficient to support the establishment of vegetative growth to meet stabilization or restoration requirements.

(e) Equipment may not be refueled within the floodway or within 50 feet of any body of water.

(f) Materials staging areas must be located outside of a floodway or greater than 50 feet from any body of water, unless otherwise approved in writing by the Department.

(g) All buried metallic gathering pipelines shall be installed and placed in operation in accordance with 49 CFR Part 192, Subpart I or Part 195, Subpart H (relating to requirements for corrosion control; and corrosion control).

§ 78a.68a. Horizontal directional drilling for oil and gas pipelines.

(a) Horizontal directional drilling activities associated with pipeline construction related to oil and gas operations, including gathering and transmission pipelines, that occur beneath any body of water or watercourse may not begin prior to authorization by the Department in accordance with Chapters 102 and 105 (relating to erosion and sediment control; and dam safety and waterway management).

(b) Prior to beginning of any horizontal directional drilling activity, the person planning to conduct those activities shall develop a PPC plan under § 102.5(1) (relating to permit requirements). The PPC plan must include a site-specific contingency plan that describes the measures to be taken to control, contain and collect any discharge of drilling fluids and minimize impacts to waters of the Commonwealth. The PPC plan must be present onsite during drilling operations and shall be made available to the Department upon request.

(c) The Department shall be notified at least 24 hours prior to beginning of any horizontal directional drilling activities, including conventional boring, beneath any body of water or watercourse. Notice shall be made electronically to the Department through its web site and include the name of the municipality where the activities will occur, GPS coordinates of the entry point of the drilling operation and the date when drilling will begin.

(d) All required permits and Safety Data Sheets must be onsite during horizontal directional drilling activities and shall be made available to the Department upon request.

(e) Materials staging areas shall be located outside of a floodway, as defined in § 105.1 (relating to definitions), of any watercourse or greater than 50 feet from any body of water, unless otherwise approved in writing by the Department.

(f) Drilling fluid additives other than bentonite and water shall be approved by the Department prior to use. All approved horizontal directional drilling fluid additives will be listed on the Department's web site. Use of a preapproved horizontal directional drilling fluid additive does not require separate Department approval.

(g) Horizontal directional drilling activities shall be monitored for pressure and loss of drilling fluid returns. Bodies of water and watercourses over and adjacent to horizontal directional drilling activities shall also be monitored for any signs of drilling fluid discharges. Monitoring shall be in accordance with the PPC plan.

(h) Horizontal directional drilling activities may not result in a discharge of drilling fluids to waters of the Commonwealth. If a discharge occurs during horizontal directional drilling activities, the person subject to subsection (a) shall immediately implement the contingency plan developed under subsection (b).

(i) When a drilling fluid discharge or loss of drilling fluid circulation is discovered, the loss or discharge shall be immediately reported to the Department, and the person subject to subsection (a) shall request an emergency permit under § 105.64 (relating to emergency permits), if necessary for emergency response or remedial activities to be conducted.

(j) Any water supply complaints received by the person subject to subsection (a) shall be reported to the Department within 24 hours electronically through its web site.

(k) Horizontal directional drilling fluid returns and drilling fluid discharges shall be managed in accordance with Subpart D, Article IX (relating to residual waste management).

§ 78a.68b. Well development pipelines for oil and gas operations.

(a) The construction, installation, use, maintenance, repair and removal of well development pipelines shall meet applicable requirements in Chapters 102 and 105 (relating to erosion and sediment control; and dam safety and waterway management).

(b) Operators shall install well development pipelines that transport fluids other than fresh ground water, surface water, water from water purveyors or other Department-approved sources aboveground except when crossing pathways, roads or railways where the pipeline may be installed below ground surface, or crossing a watercourse or body of water where the pipeline may be installed below the ground surface with prior Department approval.

(c) Well development pipelines may not be installed through existing stream culverts, storm drain pipes or under bridges crossing streams without approval by the Department under § 105.151 (relating to permit applications for construction or modification of culverts and bridges).

(d) The section of a well development pipeline crossing over a watercourse or body of water, except wetlands, may not have joints or couplings unless secondary containment is provided. Well development pipeline crossings over wetlands must utilize a single section of pipe to the extent practicable. Shut off valves shall be installed on both sides of the temporary crossing.

(e) In addition to the requirements of subsection (c), well development pipelines used to transport fluids other than fresh ground water, surface water, water from water purveyors or approved sources must have shut off valves, check valves or other methods of segmenting the pipeline placed at designated intervals, to be determined by the pipeline diameter, that prevent the discharge of more than 1,000 barrels of fluid. Elevation changes that would effectively limit flow in the event of a pipeline leak shall be taken into consideration when determining the placement of shut off valves and be considered effective flow barriers.

(f) Highly visible flagging, markers or signs shall be placed at regular intervals, no greater than 75 feet, along the entire length of the well development pipeline.

(g) Well development pipelines shall be pressure tested prior to being first placed into service and after the pipeline is moved, repaired or altered. A passing test is holding 125% of the anticipated maximum pressure for 2 hours. Leaks or other defects discovered during pressure

testing shall be repaired prior to use. Pressure test results and any defects and repairs to the well development pipeline shall be documented and made available to the Department upon request.

(h) Water used for hydrostatic pressure testing shall be discharged in a manner that does not result in a discharge to waters of the Commonwealth unless approved by the Department in writing.

(i) Well development pipelines shall be inspected prior to and during each day the pipeline is not emptied and depressurized. Inspection dates and any defects and repairs to the well development pipeline shall be documented and made available to the Department upon request.

(j) Well development pipelines not used to transport fluids for more than 7 consecutive calendar days shall be emptied and depressurized. In no case may a well development pipeline be used to transport or store fluids for more than 12 months without approval from the Department.

(k) Flammable materials may not be transported through a well development pipeline.

(l) Well development pipelines shall be removed in accordance with the required restoration timeline of the well site it serviced under § 78a.65 (relating to site restoration).

(m) An operator shall keep records regarding the location of all well development pipelines, the type of fluids transported through those pipelines and the approximate period of time that the pipeline was installed. The records shall be made available to the Department upon request.

(n) Records required under this section shall be retained by the operator for 1 year after the well development pipeline is removed.

§ 78a.69. Water management plans.

(a) *General.*

(1) Except as provided in paragraph (2), a person may not withdraw or use water from water sources within this Commonwealth for drilling or hydraulic fracture stimulation of any natural gas well governed by this chapter except in accordance with a WMP approved by the Department. The WMP must demonstrate that the withdrawal and use of the water sources protects those water sources as required by law and protects public health, safety and welfare.

(2) A water purveyor that has a water allocation permit or order of confirmation under the act of June 24, 1939 (P.L. 842, No. 365) (32 P.S. §§ 631—641), known as the Water Rights Law, or a safe drinking water permit under the Pennsylvania Safe Drinking Water Act (35 P.S. §§ 721.1—721.17), as applicable, is not required to apply for a WMP under this section.

(b) *WMP requirements.* A WMP must meet the following requirements:

- (1) Protect instream flow.
- (2) Prevent adverse effects on quantity and quality of water available to other users.
- (3) Protect and maintain designated and existing uses of water sources.
- (4) Prevent adverse impacts to water quality in the watershed considered as a whole.
- (5) Protect groundwater resources including nearby water wells.

(6) Provide for water reuse.

(c) *Application requirements.* A request for approval under this section shall be submitted on forms furnished by the Department and must include, but not be limited to, the following:

(1) General water source information including identification of source name, source type, average daily and instantaneous maximum withdrawal rates.

(2) A plan for monitoring and reporting of water sources and uses.

(3) A low flow analysis.

(4) A withdrawal and diversion impact analysis.

(5) A description of how the proposed withdrawal will not adversely affect the quantity or quality of water available to other users of the same water sources. When obtaining water from a water purveyor, the application must include a description of how the withdrawal will not adversely affect the water purveyor's system.

(6) For surface water sources:

(i) An operations plan that includes an intake design, a flow schematic showing how water is to be withdrawn, a site layout and a footprint for each surface water withdrawal.

(ii) A description of measures to be taken to prevent the rapid movement of invasive, harmful or nuisance species by vehicles, equipment or other facilities from one site to another.

(7) For groundwater sources, a well report that includes information necessary to evaluate:

(i) Proper well construction.

(ii) The hydraulic characteristics of the aquifer.

(iii) The suitability of the proposed groundwater source.

(iv) Proper well abandonment.

(v) Information consistent with Department guidance, including the *Public Water Supply Manual*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 383-2125-108, as amended and updated, and the *Groundwater Monitoring Guidance Manual*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 383-3000-001, as amended and updated, satisfies this requirement.

(8) A reuse plan for fluids that will be used to hydraulically fracture wells. Proof of a wastewater source reduction strategy in compliance with § 95.10(b) (relating to treatment requirements for new and expanding mass loadings of Total Dissolved Solids (TDS)) satisfies the reuse plan requirement.

(9) Proof of consultation with the Pennsylvania Natural Heritage Program regarding the presence of a State or Federal threatened or endangered species at the location of a withdrawal.

(10) Proof of notification of the proposed withdrawal to municipalities and counties where the water source will be located.

(11) Proof of consultation with the Pennsylvania Historic and Museum Commission regarding the presence of a historical or archaeological site included on the Federal or State list of historical places at the location of a withdrawal.

(d) *Approval of WMPs.* The Department will presume that the requirements in subsection (b) and section

3211(m)(2) of the act (relating to well permits) are met when an approval from the Susquehanna River Basin Commission, the Delaware River Basin Commission or the parties to the Great Lakes-St. Lawrence River Basin Water Resources Compact is obtained for a water withdrawal, to the extent that the requirements in subsection (c) are considered in granting the approval.

(e) *Operational requirements.* A person whose WMP has been approved by the Department shall comply with the WMP, and shall meet the following:

(1) Prior to any withdrawal, post a sign at the entrance to the water source withdrawal location displaying the name of the person and contact telephone number, water withdrawal approval conditions including daily withdrawal volume, maximum instantaneous withdrawal rate and passby flow requirements, if applicable, and the WMP water source expiration date.

(2) Measure water withdrawals and purchases using continuous-recording devices or flow meters. Water sources having passby flow conditions shall conduct instream flow monitoring and measuring using methods acceptable to the Department.

(3) Submit reports to the Department by electronic means consisting of daily withdrawal volumes, in-stream flow measurements or water source purchases, or both, as required by the Department.

(4) Retain withdrawal data and daily instream flow measurements and purchases for at least 5 years. These records shall be available for review by the Department upon request.

(f) *Administration of WMPs.*

(1) Approvals for individual water sources within a WMP are valid for 5 years.

(2) A WMP renewal application shall be submitted at least 6 months prior to the expiration of the 5-year term for withdrawal or use of a water source under a WMP.

(3) The Department may suspend or revoke an approved water source within a WMP for failure to comply with the WMP or for any reasons in section 3211(m) of the act and sections 3252 and 3259 of the act (relating to public nuisances; and unlawful conduct).

(4) A person whose WMP has been approved by the Department may terminate approval of any water source within an approved WMP by submitting a letter to the Department's Oil and Gas District Office requesting termination of the water source approval.

(g) *Denial.* The Department may deny an application for a WMP for either of the following reasons:

(1) The WMP application is administratively incomplete.

(2) The WMP application does not demonstrate that the requirements of this section will be met.

§ 78a.70. Road-spreading of brine for dust control and road stabilization.

Production brines from unconventional wells may not be used for dust suppression and road stabilization.

§ 78a.70a. Pre-wetting, anti-icing and de-icing.

Production brines from unconventional wells may not be used for pre-wetting, anti-icing and de-icing.

**Subchapter D. WELL DRILLING, OPERATION AND PLUGGING
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GENERAL

§ 78a.71. Use of safety devices—well casing.

(a) The operator shall equip the well with one or more strings of casing of sufficient cemented length and strength to attach proper well control equipment and prevent blowouts, explosions, fires and casing failures during installation, completion and operation.

(b) The operator shall determine the amount and type of casing to be run and the amount and type of cement to be used in accordance with current prudent industry practices and engineering. In making the determinations, the operator shall consider the following:

- (1) Successful local practices for similar wells.
- (2) Maximum anticipated surface pressure.
- (3) Collapse resistance.
- (4) Tensile strength.
- (5) Chemical environment.
- (6) Potential mechanical damage.
- (7) Manufacturing standards, including American Petroleum Institute or equivalent specifications for pipe

used in wells drilled below the Onondaga formation or where blow-out preventers are required.

§ 78a.72. Use of safety devices—blow-out prevention equipment.

(a) The operator shall use blow-out prevention equipment after setting casing with a competent casing seat in the following circumstances:

(1) When drilling a well that is intended to produce natural gas from an unconventional formation.

(2) When drilling out solid core hydraulic fracturing plugs to complete a well.

(3) When well head pressures or natural open flows are anticipated at the well site that may result in a loss of well control.

(4) When the operator is drilling in an area where there is no prior knowledge of the pressures or natural open flows to be encountered.

(5) On wells regulated by the Oil and Gas Conservation Law (58 P.S. §§ 401—419).

(6) When drilling within 200 feet of a building.

(b) Blow-out prevention equipment used must be in good working condition at all times.

(c) Controls for the blow-out preventer shall be accessible to allow actuation of the equipment. Additional controls for a blow-out preventer with a pressure rating of greater than 3,000 psi, not associated with the rig hydraulic system, shall be located at least 50 feet away from the drilling rig so that the blow-out preventer can be actuated if control of the well is lost.

(d) The operator shall use pipe fittings, valves and unions placed on or connected to the blow-out prevention systems that have a working pressure capability that exceeds the anticipated pressures.

(e) The operator shall conduct a complete test of the ram type blow-out preventer and related equipment for both pressure and ram operation before placing it in service on the well. The operator shall test the annular type blow-out preventer in accordance with the manufacturer's published instructions, or the instructions of a professional engineer, prior to the device being placed in service. Blow-out prevention equipment that fails the test may not be used until it is repaired and passes the test.

(f) When the equipment is in service, the operator shall visually inspect blow-out prevention equipment during each tour of drilling operation and during actual drilling operations test the pipe rams for closure daily and the blind rams for closure on each round trip. When more than one round trip is made in a day, one daily closure test for blind rams is sufficient. Testing shall be conducted in accordance with American Petroleum Institute publication API RP53, "API Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells," or other procedure approved by the Department. The operator shall record the results of the inspection and closure test in the drillers log before the end of the tour. If blow-out prevention equipment is not in good working order, drilling shall cease when cessation of drilling can be accomplished safely and not resume until the blow-out prevention equipment is repaired or replaced and retested.

(g) All lines, valves and fittings between the closing unit and the blow-out preventer stack must be flame

resistant and have a rated working pressure that meets or exceeds the requirements of the blow-out preventer system.

(h) When a blowout preventer is installed or required under subsection (a), there shall be present on the well site an individual with a current certification from a well control course accredited by the International Association of Drilling Contractors or other organization approved by the Department. The certification shall be available for review at the well site. The Department will maintain a list of approved accrediting organizations on its web site.

(i) Well drilling and completion operations requiring pressure barriers, as identified by the operator under § 78a.55(d) (relating to control and disposal planning; emergency response for unconventional wells), shall employ at least two mechanical pressure barriers between the open producing formation and the atmosphere that are capable of being tested. The mechanical pressure barriers shall be tested according to manufacturer specifications prior to operation. If during the course of operations the operator only has one functioning barrier, operations shall cease until additional barriers are added and tested or the redundant barrier is repaired and tested. Stripper rubber or a stripper head may not be considered a barrier.

(j) A coiled tubing rig or a hydraulic workover unit with appropriate blowout prevention equipment shall be employed during post-completion cleanout operations in horizontal unconventional formations.

(k) The minimum amount of intermediate casing that is cemented to the surface to which blow-out prevention equipment may be attached shall be in accordance with the following:

<i>Proposed Total Vertical Depth (in feet)</i>	<i>Minimum Cemented Casing Required (in feet of casing cemented)</i>
Up to 5,000	400
5,001 to 5,500	500
5,501 to 6,000	600
6,001 to 6,500	700
6,501 to 7,000	800
7,001 to 8,000	1,000
8,001 to 9,000	1,200
9,001 to 10,000	1,400
Deeper than 10,000	1,800

(l) Upon completion of the drilling operations at a well, the operator shall install and utilize equipment, such as a shut-off valve of sufficient rating to contain anticipated pressure, lubricator or similar device, as may be necessary to enable the well to be effectively shut-in while logging and servicing the well and after completion of the well.

§ 78a.73. General provision for well construction and operation.

(a) The operator shall construct and operate the well in accordance with this chapter and ensure that the integrity of the well is maintained and health, safety, environment and property are protected.

(b) The operator shall prevent gas, oil, brine, completion and servicing fluids, and any other fluids or materials from below the casing seat from entering fresh

groundwater, and shall otherwise prevent pollution or diminution of fresh groundwater.

(c) The operators of active, inactive, abandoned, and plugged and abandoned wells identified as part of an area of review survey conducted under § 78a.52a (relating to area of review) that likely penetrate within 1,500 feet measured vertically from the stimulation perforations, if known, shall be notified. Notice shall be provided at least 30 days prior to the start of drilling the well or at the time the permit application is submitted to the Department if the start of drilling is planned less than 30 days from the date of permit issuance. Orphan wells, abandoned wells, and plugged and abandoned wells identified as part of an area of review survey conducted under § 78a.52a that either penetrate within 1,500 feet measured vertically from the stimulation perforations or have an unknown true vertical depth shall be visually monitored during stimulation activities. The operator shall immediately notify the Department of any change to a well being monitored, of any treatment pressure or volume changes indicative of abnormal fracture propagation at the well being stimulated or if otherwise made aware of a confirmed well communication incident associated with their stimulation activities. Notice shall be provided to the Department electronically through the Department's web site. In an event such as this, the operator shall cease stimulating the well that is the subject of the area of review survey and take action to prevent pollution of waters of the Commonwealth or discharges to the surface. The operator may not resume stimulation of the well that is the subject of the area of review survey without Department approval.

(d) An operator that alters an orphan well, or an abandoned well or plugged and abandoned well by hydraulic fracturing shall plug the altered well in accordance with this chapter, or the operator may adopt the altered well and place it into production.

(e) After a well has been completed, recompleted, reconditioned or altered the operator shall prevent surface shut-in pressure and surface producing back pressure inside the surface casing or coal protective casing from exceeding the following pressure: 80% multiplied by 0.433 psi per foot multiplied by the casing length (in feet) of the applicable casing.

(f) After a well has been completed, recompleted, reconditioned or altered, if the surface shut-in pressure or surface producing back pressure exceeds the pressure as calculated in subsection (e), the operator shall take action to prevent the migration of gas and other fluids from lower formations into fresh groundwater. To meet this standard the operator may cement or install on a packer sufficient intermediate or production casing or take other actions approved by the Department. This section does not apply during testing for mechanical integrity in accordance with State or Federal requirements.

(g) Excess gas encountered during drilling, completion or stimulation shall be flared, captured or diverted away from the drilling rig in a manner that does not create a hazard to the public health or safety.

(h) The well must be equipped with a check valve to prevent backflow from the pipelines into the well.

§ 78a.74. Venting of gas.

The venting of gas to the atmosphere from a well is prohibited when the venting produces a hazard to the public health and safety.

§ 78a.75. Alternative methods.

(a) A well operator may request approval from the Department to use an alternative method or material for the casing, plugging or equipping of a well under section 3221 of the act (relating to alternative methods).

(b) A well operator seeking approval under this section shall file an application with the Department on forms furnished by the Department. The application must:

(1) Describe the proposed alternative method or material, in reasonable detail.

(2) Indicate the manner in which the alternative will satisfy the goals of the act and this chapter.

(3) Include a drawing or schematic of the alternative method, if appropriate.

(c) The well operator shall notify all coal owners and operators and gas storage operators of record of the proposal, by certified mail. The well operator shall state in the application that he has sent the certified mail notice to the coal owners and operators and gas storage operators of record, either simultaneously with or prior to submitting the proposal to the Department.

(d) The coal owners and operators and gas storage operators of record shall have up to 15 days from their receipt of the notice to file objections or to indicate concurrence with the proposed alternative method or material.

(e) If no objections are filed within 15 days from receipt of the notice, and if none are raised by the Department, the Department will make a determination whether to allow the use of the proposed alternative method or material.

§ 78a.75a. Area of alternative methods.

(a) A well operator may request approval from the Department to use an alternative method or material for the casing, plugging or equipping of a well under section 3221 of the act (relating to alternative methods).

(b) To establish an area of alternative methods, the Department will publish a notice in the *Pennsylvania Bulletin* of the proposed area of alternative methods and provide the public with an opportunity to comment on the proposal. After reviewing any comments received on the proposal, the Department will publish a final designation of the area and required alternative methods in the *Pennsylvania Bulletin*.

(c) Wells drilled within an area of alternative methods established under subsection (b) must meet the requirements specified by the Department unless the operator obtains approval from the Department to drill, operate or plug the well in a different manner that is at least as safe and protective of the environment as the requirements of the area of alternative methods.

§ 78a.76. Drilling within a gas storage reservoir area.

(a) An operator proposing to drill a well within a gas storage reservoir area or a reservoir protective area shall forward by certified mail a copy of the well location plat, the drilling, casing and cementing plan, and the anticipated date drilling will start to the gas storage reservoir operator and to the Department for approval by the Department and shall submit proof of notification to the gas storage reservoir operator to the Department with the well permit application.

(b) The storage operator may file an objection with the Department to the drilling, casing and cementing plan or

the proposed well location within 15 calendar days of receipt of the notification and request a conference in accordance with section 3251 of the act (relating to conferences).

§ 78a.77. Wells in a hydrogen sulfide area.

(a) An operator proposing to drill a well within a 1-mile radius of a well drilled to or through the same formation where hydrogen sulfide has been found while drilling shall install monitoring equipment during drilling at the well site to detect the presence of hydrogen sulfide in accordance with American Petroleum Institute publication RP49, "Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide."

(b) When hydrogen sulfide is detected in concentrations of 20 ppm or greater, the well shall be drilled in accordance with American Petroleum Institute publication RP49, "Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide."

(c) An operator who operates a well in which hydrogen sulfide is discovered in concentrations of 20 ppm or greater shall operate the well in a way that presents no danger to human health or to the environment.

(d) When an operator discovers hydrogen sulfide in concentrations of 20 ppm or greater during the drilling of a well, the operator shall notify the Department and identify the location of the well and the concentration of hydrogen sulfide detected. The Department will maintain a list of all notices that will be available to operators for their reference.

§ 78a.78. Pillar permit applications.

(a) The Department will use recommendations for coal pillar size and configuration set forth in the coal pillar study, listed in the Department's *Coal Pillars*, Commonwealth of Pennsylvania, Department of Environmental Protection, No. 550-2100-006, as amended and updated, as a basis for approval or disapproval of coal pillar permit applications submitted by underground coal mine operators.

(b) Where proposed coal pillar size and configuration does not conform to the recommendations of the coal pillar study referenced in subsection (a), the underground coal mine operator may request Department approval for an alternate coal pillar size and configuration.

CASING AND CEMENTING

§ 78a.81. General provisions.

(a) The operator shall conduct casing and cementing activities under this section and §§ 78a.82, 78a.83, 78a.83a, 78a.83b, 78a.83c and 78a.84—78a.87 or an approved alternate method under § 78a.75 (relating to alternative methods). The operator shall case and cement a well to accomplish the following:

- (1) Allow effective control of the well at all times.
- (2) Prevent the migration of gas or other fluids into sources of fresh groundwater.
- (3) Prevent pollution or diminution of fresh groundwater.
- (4) Prevent the migration of gas or other fluids into coal seams.

(b) The operator shall drill through fresh groundwater zones with diligence and as efficiently as practical to minimize drilling disturbance and commingling of groundwaters.

§ 78a.82. Use of conductor pipe.

If the operator installs conductor pipe in the well, the following provisions apply:

- (1) The operator may not remove the pipe.
- (2) Conductor pipe shall be installed in a manner that prevents the subsurface infiltration of surface water or fluids by either driving the pipe into place or cementing the pipe from the seat to the surface.
- (3) Conductor pipe must be made of steel unless a different material is approved for use by the Department.

§ 78a.83. Surface and coal protective casing and cementing procedures.

(a) For wells drilled, altered, reconditioned or recompleted after February 5, 2011, surface casing or any casing functioning as a water protection casing may not be utilized as production casing unless one of the following applies:

- (1) In oil wells where the operator does not produce any gas generated by the well and the annulus between the surface casing and the production pipe is left open.
- (2) The operator demonstrates that the pressure in the well is no greater than the pressure permitted under § 78a.73(e) (relating to general provision for well construction and operation), demonstrates through a pressure test or other method approved by the Department that all gas and fluids will be contained within the well, and installs a working pressure gauge that can be inspected by the Department.

(b) If the well is to be equipped with threaded and coupled casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing collar to be installed. If the well is to be equipped with plain-end welded casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing coupling.

(c) The operator shall drill to approximately 50 feet below the deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper, and immediately set and permanently cement a string of surface casing to that depth. Except as provided in subsection (f), the surface casing may not be set more than 200 feet below the deepest fresh groundwater except if necessary to set the casing in consolidated rock. The surface hole shall be drilled using air, freshwater or freshwater-based drilling fluid. Prior to cementing, the wellbore shall be conditioned to ensure an adequate cement bond between the casing and the formation. The surface casing seat shall be set in consolidated rock. When drilling a new well or re-drilling an existing well, the operator shall install at least one centralizer within 50 feet of the casing seat and then install a centralizer in intervals no greater than every 150 feet above the first centralizer.

(d) The operator shall permanently cement the surface casing by placing the cement in the casing and displacing it into the annular space between the wall of the hole and the outside of the casing.

(e) Where potential oil or gas zones are anticipated to be found at depths within 50 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas.

(f) If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall document the depth of the fresh groundwater zone in the well record and protect the additional

fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the various zones. Sufficient cement shall be used to cement the casing to the surface. The operator shall install at least one centralizer within 50 feet of the casing seat and then install a centralizer in intervals no greater than, if possible, every 150 feet above the first centralizer.

(g) The operator shall set and cement a coal protective string of casing through workable coal seams. The base of the coal protective casing shall be at least 30 feet below the lowest workable coal seam. The operator shall install at least two centralizers. One centralizer shall be within 50 feet of the casing seat and the second centralizer shall be within 100 feet of the surface.

(h) Unless an alternative method has been approved by the Department in accordance with § 78a.75 (relating to alternative methods), when a well is drilled through a coal seam at a location where the coal has been removed or when a well is drilled through a coal pillar, the operator shall drill to a depth of at least 30 feet but no more than 50 feet deeper than the bottom of the coal seam. The operator shall set and cement a coal protection string of casing to this depth. The operator shall equip the casing with a cement basket or other similar device above and as close to the top of the coal seam as practical. The bottom of the casing must be equipped with an appropriate device designed to prevent deformation of the bottom of the casing. The interval from the bottom of the casing to the bottom of the coal seam shall be filled with cement either by the balance method or by the displacement method. Cement shall be placed on top of the basket between the wall of the hole and the outside of the casing by pumping from the surface. If the operator penetrates more than one coal seam from which the coal has been removed, the operator shall protect each seam with a separate string of casing that is set and cemented or with a single string of casing which is stage cemented so that each coal seam is protected as described in this subsection. The operator shall cement the well to isolate workable coal seams from each other.

(i) If the operator sets and cements casing under subsection (g) or (h) and subsequently encounters additional fresh groundwater zones below the deepest cemented casing string installed, the operator shall protect the fresh groundwater by installing and cementing another string of casing or other method approved by the Department. Sufficient cement shall be used to cement the casing to the surface. The additional casing string may also penetrate zones bearing brackish or salt water, but shall be run and cemented prior to penetrating a zone known to or likely to contain oil or gas. The operator shall install at least one centralizer within 50 feet of the casing seat and then, if possible, install a centralizer in intervals no greater than every 150 feet above the first centralizer.

(j) If it is anticipated that cement used to permanently cement the surface casing cannot be circulated to the surface a cement basket may be installed immediately above the depth of the anticipated lost circulation zone. The casing shall be permanently cemented by the displacement method. Additional cement may be added above the cement basket, if necessary, by pumping through a pour string from the surface to fill the annular space. Filling the annular space by this method does not

constitute permanently cementing the surface or coal protective casing under § 78a.83b (relating to casing and cementing—lost circulation).

§ 78a.83a. Casing and cementing plan.

(a) The operator shall prepare and maintain a casing and cementing plan showing how the well will be drilled and completed. The plan must demonstrate compliance with this subchapter and include the following information:

- (1) The anticipated depth and thickness of any producing formation, expected pressures, anticipated fresh groundwater zones and the method or information by which the depth of the deepest fresh groundwater was determined.
- (2) The diameter of the borehole.
- (3) Casing type, whether the casing is new or used, depth, diameter, wall thickness and burst pressure rating.
- (4) Cement type, yield, additives and estimated amount.
- (5) The estimated location of centralizers.
- (6) The proposed borehole conditioning procedures.
- (7) Alternative methods or materials as required by the Department as a condition of the well permit.

(b) The plan shall be available at the well site for review by the Department.

(c) Upon request, the operator shall provide a copy of the well-specific casing and cementing plan to the Department for review and approval.

(d) Revisions to the plan made as a result of onsite modification shall be documented in the plan and be available for review by the Department. The person making the revisions to the plan shall initial and date the revisions.

§ 78a.83b. Casing and cementing—lost circulation.

(a) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface despite pumping a volume of cement equal to or greater than 120% of the calculated annular space, the operator shall determine the top of the cement, notify the Department and meet one of the following requirements as approved by the Department:

- (1) Run an additional string of casing at least 50 feet deeper than the string where circulation was lost and cement the additional string of casing back to the seat of the string where circulation was lost and vent the annulus of the additional casing string to the atmosphere at all times unless closed for well testing or maintenance. Shut-in pressure on the casing seat of the additional string of casing may not exceed the requirements of § 78a.73(e) (relating to general provision for well construction and operation).
- (2) Run production casing and set the production casing on a packer in a competent formation below the string where circulation was lost and vent the annulus of the production casing to the atmosphere at all times unless closed for well testing or maintenance.
- (3) Run production casing at least to the top of the formation that is being produced and cement the production casing to the surface.
- (4) Run intermediate and production casing and cement both strings of casing to the surface.

(5) Produce oil but not gas and leave the annulus between the surface casing and the production pipe open.

(b) In addition to meeting the requirements of subsection (a), the operator may also pump additional cement through a pour string from the surface to fill the annular space.

§ 78a.83c. Intermediate and production casing.

(a) Prior to cementing the intermediate and production casing, the borehole, mud and cement shall be conditioned to ensure an adequate cement bond between the casing and the formation.

(b) If the well is to be equipped with an intermediate casing, centralizers shall be used and the casing shall be cemented to the surface by the displacement method. Gas may be produced off the intermediate casing if a shoe test demonstrates that all gas will be contained within the well and a relief valve is installed at the surface that is set less than the shoe test pressure. The shoe test pressure shall be recorded in the completion report.

(c) Except as provided in § 78a.83 (relating to surface and coal protective casing and cementing procedures), each well must be equipped with production casing. The production string may be set on a packer or cemented in place. If the production casing is cemented in place, centralizers shall be used and cement shall be placed by the displacement method with sufficient cement to fill the annular space to a point at least 500 feet above true vertical depth or at least 200 feet above the uppermost perforations, whichever is greater.

§ 78a.84. Casing standards.

(a) The operator shall install casing that can withstand the effects of tension, and prevent leaks, burst and collapse during its installation, cementing and subsequent drilling and producing operations.

(b) Except as provided in subsection (c), all casing must be a string of new pipe with an internal pressure rating that is at least 20% greater than the anticipated maximum pressure to which the casing will be exposed.

(c) Used casing may be approved for use as surface, intermediate or production casing but shall be pressure tested after cementing and before continuation of drilling. A passing pressure test is holding the anticipated maximum pressure to which it will be exposed for 30 minutes with not more than a 10% decrease in pressure.

(d) New or used plain end casing, except when being used as conductor pipe, that is welded together for use must meet the following requirements:

(1) The casing must pass a pressure test by holding the anticipated maximum pressure to which the casing will be exposed for 30 minutes with not more than a 10% decrease in pressure. The operator shall notify the Department at least 24 hours before conducting the test. The test results shall be entered on the drilling log.

(2) The casing shall be welded using at least three passes with the joint cleaned between each pass.

(3) The casing shall be welded by a person trained and certified in the applicable American Petroleum Institute, American Society of Mechanical Engineers, American Welding Society or equivalent standard for welding casing and pipe or an equivalent training and certification program as approved by the Department. The certification requirements of this paragraph shall take effect August 5, 2011. A person with 10 years or more of

experience welding casing as of February 5, 2011, who registered with the Department by November 7, 2011, is deemed to be certified.

(e) When casing through a workable coal seam, the operator shall install coal protective casing that has a minimum wall thickness of 0.23 inch.

(f) Casing which is attached to a blow-out preventer with a pressure rating of greater than 3,000 psi shall be pressure tested after cementing. A passing pressure test must be holding the anticipated maximum pressure to which the casing will be exposed for 30 minutes with not more than a 10% decrease. Certification of the pressure test shall be confirmed by entry and signature of the person performing the test on the driller's log.

§ 78a.85. Cement standards.

(a) When cementing surface casing or coal protective casing, the operator shall use cement that meets or exceeds the ASTM International C 150, Type I, II or III Standard or API Specification 10. The cement must also:

(1) Secure the casing in the wellbore.

(2) Isolate the wellbore from fresh groundwater.

(3) Contain any pressure from drilling, completion and production.

(4) Protect the casing from corrosion from, and degradation by, the geochemical, lithologic and physical conditions of the surrounding wellbore. For wells employing coal protective casing, this includes, but is not limited to, formulating cement to withstand elevated sulfate concentrations and other geochemical constituents of coal and associated strata which have the potential to adversely affect the integrity of the cement.

(5) Prevent gas flow in the annulus. In areas of known shallow gas producing zones, gas block additives and low fluid loss slurries shall be used.

(b) After the casing cement is placed behind surface casing, the operator shall permit the cement to set to a minimum designed compressive strength of 350 pounds per square inch (psi) at the casing seat. The cement placed at the bottom 300 feet of the surface casing must constitute a zone of critical cement and achieve a 72-hour compressive strength of 1,200 psi and the free water separation may be no more than 6 milliliters per 250 milliliters of cement. If the surface casing is less than 300 feet, the entire cemented string constitutes a zone of critical cement.

(c) After any casing cement is placed and cementing operations are complete, the casing may not be disturbed for a minimum of 8 hours by doing any of the following:

(1) Releasing pressure on the cement head within 4 hours of cementing if casing equipment check valves did not hold or casing equipment was not equipped with check valves. After 4 hours, the pressure may be released at a continuous, gradual rate over the next 4 hours provided the floats are secure.

(2) Nipping up on or in conjunction to the casing.

(3) Slacking off by the rig supporting the casing in the cement sheath.

(4) Running drill pipe or other mechanical devices into or out of the wellbore with the exception of a wireline used to determine the top of cement.

(d) Where special cement or additives are used, the operator may request approval from the Department to reduce the cement setting time specified in subsection (c).

(e) The operator shall notify the Department a minimum of 1 day before cementing of the surface casing begins, unless the cementing operation begins within 72 hours of the start of drilling.

(f) A copy of the cement job log shall be available at the well site for inspection by the Department during drilling operations. The cement job log must include the mix water temperature and pH, type of cement with listing and quantity of additive types, the volume, yield and density in pounds per gallon of the cement and the amount of cement returned to the surface, if any. Cementing procedural information must include a description of the pumping rates in barrels per minute, pressures in psi, time in minutes and sequence of events during the cementing operation.

(g) The cement job log shall be maintained by the operator after drilling operations for at least 5 years and be made available to the Department upon request.

§ 78a.86. Defective casing or cementing.

In a well that has defective, insufficient or improperly cemented casing, the operator shall report the defect to the Department within 24 hours of discovery by the operator and shall correct the defect. The operator shall correct the defect or submit a plan to correct the defect for approval by the Department within 30 days. If the defect cannot be corrected or an alternate method is not approved by the Department, the well shall be plugged under §§ 78a.91—78a.98 (relating to plugging).

§ 78a.87. Gas storage reservoir protective casing and cementing procedures.

(a) In addition to the other provisions in this subchapter, a well drilled through a gas storage reservoir or a gas storage reservoir protective area shall be drilled, cased and cemented as follows:

(1) An operator shall use drilling procedures capable of controlling anticipated gas flows and pressures when drilling from the surface to 200 feet above a gas storage reservoir or gas storage horizon.

(2) An operator shall use drilling procedures capable of controlling anticipated gas storage reservoir pressures and flows at all times when drilling from 200 feet above a gas storage reservoir horizon to the depth at which the gas storage protective casing will be installed. Operators shall use blow-out prevention equipment with a pressure rating in excess of the allowable maximum storage pressure for the gas storage reservoir.

(3) To protect the gas storage reservoir, an operator shall run intermediate or production casing from a point located at least 100 feet below the gas storage horizon to the surface. The operator shall cement this casing by circulating cement to a point at least 200 feet above the gas storage reservoir or gas storage horizon.

(4) When cementing casing in a well drilled through a gas storage reservoir, the operator shall ensure that no gas is present in the drilling fluids in an amount that could interfere with the integrity of the cement.

(b) A request by an operator for approval from the Department to use an alternative method or material for the casing, plugging or equipping of a well drilled through a gas storage reservoir under section 3221 of the act (relating to alternative methods) shall be made in accordance with § 78a.75 (relating to alternative methods).

OPERATING WELLS

§ 78a.88. Mechanical integrity of operating wells.

(a) Except for wells that have been granted inactive status, the operator shall inspect each operating well at

least quarterly to ensure it is in compliance with the well construction and operating requirements of this chapter and the act. The results of the inspections shall be recorded and retained by the operator for at least 5 years and be available for review by the Department and the coal owner or operator.

(b) At a minimum, inspections shall determine:

(1) The well-head pressure or water level measurement.

(2) The open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in.

(3) If there is evidence of gas escaping from the well and the amount escaping, using measurement or best estimate of quantity.

(4) If there is evidence of progressive corrosion, rusting or other signs of equipment deterioration.

(c) For structurally sound wells in compliance with § 78a.73(e) (relating to general provision for well construction and operation), the operator shall follow the reporting schedule outlined in subsection (e).

(d) For wells exhibiting progressive corrosion, rusting or other signs of equipment deterioration that compromise the integrity of the well, or the well is not in compliance with § 78a.73(e), the operator shall immediately notify the Department and take corrective actions to repair or replace defective equipment or casing or mitigate the excess pressure on the surface casing seat or coal protective casing seat according to the following hierarchy:

(1) The operator shall reduce the shut-in or producing back pressure on the casing seat to achieve compliance with § 78a.73(e).

(2) The operator shall retrofit the well by installing production casing to reduce the pressure on the casing seat to achieve compliance with § 78a.73(e). The annular space surrounding the production casing must be open to the atmosphere. The production casing shall be either cemented to the surface or installed on a permanent packer. The operator shall notify the Department at least 7 days prior to initiating the corrective measure.

(3) Additional mechanical integrity tests, including, but not limited to, pressure tests, may be required by the Department to demonstrate the integrity of the well.

(e) The operator shall submit an annual report to the Department identifying the compliance status of each well with the mechanical integrity requirements of this section. The report shall be submitted on forms prescribed by, and available from, the Department or in a similar manner approved by the Department.

§ 78a.89. Gas migration response.

(a) When an operator or owner is notified of or otherwise made aware of a potential natural gas migration incident, the operator shall immediately conduct an investigation of the incident. The purpose of the investigation is to determine the nature of the incident, assess the potential for hazards to public health and safety, and mitigate any hazard posed by the concentrations of stray natural gas.

(b) The investigation undertaken by the operator under subsection (a) shall include, but not be limited to, the following:

(1) A site visit and interview with the complainant to obtain information about the complaint and to assess the reported natural gas migration incident.

(2) A field survey to assess the presence and concentrations of natural gas and aerial extent of the stray natural gas.

(3) If necessary, establishment of monitoring locations at potential sources, in potentially impacted structures and the subsurface.

(c) If combustible gas is detected inside a building or structure at concentrations equal to or greater than 10% of the L.E.L., the operator shall do the following:

(1) Immediately notify the Department, local emergency response agency, gas and electric utility companies, police and fire departments, and, in conjunction with the Department and local emergency response agencies, take measures necessary to ensure public health and safety.

(2) Initiate mitigation measures necessary to control and prevent further migration.

(3) Implement the additional investigation and mitigation measures as provided in subsection (e)(1)—(5).

(d) The operator shall notify the Department and, in conjunction with the Department, take measures necessary to ensure public health and safety, if sustained detectable concentrations of combustible gas satisfy any of the following:

(1) Greater than 1% and less than 10% of the L.E.L., in a building or structure.

(2) Equal to or greater than 25% of the L.E.L. in a water well head space.

(3) Detectable in the soils.

(4) Equal to or greater than 7 mg/l dissolved methane in water.

(e) The Department may require the operator to take the following additional actions:

(1) Conduct a field survey to assess the presence and concentrations of combustible gas and the areal extent of the combustible gas in the soils, surface water bodies, water wells and other potential migration pathways.

(2) Collect gas or water samples, or both, at a minimum for molecular and stable carbon and hydrogen isotope analyses from the impacted locations such as water wells, and from potential sources of the migration such as gas wells.

(3) Conduct an immediate evaluation of the operator's adjacent oil or gas wells to determine well cement and casing integrity and to evaluate the potential mechanism of migration. This evaluation may include assessing pressures for all casing intervals, reviewing records for indications of defective casing or cement, application of cement bond logs, ultrasonic imaging tools, geophysical logs and other mechanical integrity tests as required. The initial area of assessment must include wells within a radius of 2,500 feet and may be expanded if required by the Department.

(4) Take action to correct any defect in the oil and gas wells to mitigate the stray gas incident.

(5) Establish monitoring locations and monitoring frequency in consultation with the Department at potential sources, in potentially impacted structures and the subsurface.

(f) If concentrations of stray natural gas as defined in subsection (c) or (d) are not detected, the operator shall notify the Department, and do the following if requested by the Department:

(1) Conduct additional monitoring.

(2) Document findings.

(3) Submit a closure report.

(g) If concentrations of stray natural gas are detected inside a building or structure at concentrations equal to or greater than 10% of the L.E.L., the operator and owner shall file a report with the Department by phone and email within 24 hours after the interview with the complainant and field survey of the extent of stray natural gas. Additional daily or weekly reports shall be submitted if requested by the Department.

(h) For all stray natural gas migration incidents, a final written report documenting the results of the investigation shall be submitted to the Department for approval within 30 days of the close of the incident, or in a time frame otherwise approved by the Department. The final report must include the following:

(1) Documentation of all results of the investigation, including analytical data and monitoring results.

(2) Operational changes established at the operator's oil and gas wells in this Commonwealth.

(3) Measures taken by the operator to repair any defects at any of the investigated oil and gas wells.

(i) Reports submitted in accordance with this section that contain an analysis of geological or engineering data shall be prepared and sealed by a geologist or engineer licensed in this Commonwealth.

PLUGGING

§ 78a.91. General provisions.

(a) Upon abandoning a well, the owner or operator shall plug the well under §§ 78a.92—78a.98 or an approved alternate method under section 3221 of the act (relating to alternative methods) to stop the vertical flow of fluids or gas within the well bore unless one of the following applies:

(1) The Department has granted inactive status under §§ 78a.101—78a.105 (relating to inactive status).

(2) The well is part of a plugging schedule that has been approved by the Department and the operator is complying with that schedule, and the schedule takes into account potential harm that the well poses to the environment or public health and safety.

(3) The Department has approved the identification of the well as an orphan well under section 3213 of the act (relating to well registration and identification), and the Department has not determined a prior owner or operator received economic benefit after April 18, 1979, from this well other than economic benefit derived only as a landowner or from a royalty interest.

(b) The operator shall plug a well where a radioactive logging source has been lost under §§ 78a.92—78a.98 and 78a.111.

(c) When a well is being plugged from the attainable bottom, the operator shall install a 50-foot plug of cement at the attainable bottom and plug the remainder of the well under §§ 78a.92—78a.98.

(d) If the production casing cannot be retrieved, the operator shall plug strata bearing or having borne oil, gas or water by perforating the casing and squeezing cement into the annulus or other method approved by the Department. The maximum distance the stub of the uncemented production casing may extend is 100 feet below the surface casing seat or coal protective casing

seat, whichever is deeper. The uncemented portion of the casing left in the well above the total depth or attainable bottom may not extend through a formation bearing or having borne oil, gas or water or extend to a point where it interferes with subsequent plugging requirements of §§ 78a.92(a)(2) and 78a.93(a)(2) and (b)(4) (relating to wells in coal areas—surface or coal protective casing is cemented; and wells in coal areas—surface or coal protective casing anchored with a packer or cement). The remainder of the well shall be plugged under §§ 78a.92—78a.98.

(e) When plugging a well, an operator shall ensure that no gases are present in the well in an amount that could interfere with cementing the well.

(f) When plugging a well with a casing string cemented through a gas storage reservoir or reservoir protective area, an operator shall use bridge plugs immediately above and below the gas storage reservoir unless an alternate plugging plan has been approved by the Department.

(g) When a well located in a coal area is plugged to allow mining through it, the person authorized by the Department to plug the well under the act or section 13 of the Coal and Gas Resource Coordination Act (58 P.S. § 513) shall clean out the gas well to a depth of at least 200 feet below the coal seam which will be mined and, unless impracticable, to a point 200 feet below the deepest minable coal seam the well penetrates.

(h) In lieu of the plugging requirements of §§ 78a.92—78a.95 and 78a.97, an operator may cement a well from the total depth or attainable bottom to the surface. Wells in coal areas still shall meet the venting requirements of § 78a.92 or § 78a.93.

§ 78a.92. Wells in coal areas—surface or coal protective casing is cemented.

(a) In a well underlain by a workable coal seam, where the surface casing or coal protective casing is cemented and the production casing is not cemented or the production casing is not present, the owner or operator shall plug the well as follows:

(1) The retrievable production casing shall be removed by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater. The well shall be filled with nonporous material from the total depth or attainable bottom of the well to a point 50 feet below the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which shall extend for at least 50 feet above this stratum. Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. The cement plugs shall be placed in a manner that will completely seal the hole. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials approved by the Department. Where the production casing is not retrievable, the operator shall plug that portion of the well under § 78a.91(d) (relating to general provisions).

(2) After plugging strata bearing or having borne oil, gas or water, the well shall be filled with nonporous material to a point approximately 100 feet below the surface or coal protective casing seat, whichever is deeper. At this point, a 100-foot plug of cement shall be installed.

(3) After the plug has been installed below the casing seat, the inner casing shall be emptied of liquid from the surface to the plug of cement. A vent or other device approved by the Department shall then be installed on top of the inner string of casing to prevent liquids and solids from entering the well but permit access to the full internal diameter of the inner casing when required. The vent or other device approved by the Department must extend, when finally in place, a distance of at least 72 inches above ground level and the permit or registration number must be permanently affixed.

(b) The owner or operator shall plug a well, where the surface casing, coal protective casing and production casing are cemented, as follows:

(1) If the total depth or attainable bottom is deeper than the cemented production casing seat, the operator shall plug that portion of the well under subsection (a)(1).

(2) Cement plugs shall be set in the cemented portion of the production casing so that the plugs will extend from at least 50 feet below each stratum bearing or having borne oil, gas or water to a point at least 100 feet above each stratum bearing or having borne, oil, gas or water. A Department-approved mechanical plug may be set 20 feet above each stratum bearing or having borne oil, gas or water as a substitute for the plug of cement. Nonporous material must separate each cement plug or mechanical plug. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials as approved by the Department.

(3) Following the plugging of the cemented portion of the production casing, the uncemented portion of the production casing shall be separated from the cemented portion and retrieved by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater. The maximum distance the stub of the uncemented portion of the production casing may extend is 100 feet below the surface or coal protective casing whichever is lower. In no case may the uncemented portion of the casing left in the well extend through a formation bearing or having borne oil, gas or water. Other stratum above the cemented portion of the production casing bearing or having borne oil, gas or water shall be plugged by filling the hole with nonporous material to 20 feet above the stratum and setting a 50-foot plug of cement. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other material as approved by the Department. When the uncemented portion of the production casing is not retrievable, the operator shall plug that portion of the well under § 78a.91(d).

(4) After plugging all strata bearing or having borne oil, gas or water, the well shall be filled with nonporous material to a point approximately 100 feet below the surface or coal protective casing seat, whichever is deeper. At this point a 200-foot cement plug shall be placed so

that the plug extends from 100 feet below the casing seat to a point at least 100 feet above the casing seat.

(5) After the 200-foot plug has been installed, the remainder of the well shall be plugged and vented as described in subsection (a)(3).

(c) A person authorized by the Department under the act or section 13 of the Coal and Gas Resource Coordination Act (58 P.S. § 513) to plug a gas well that penetrates a workable coal seam that was drilled prior to November 30, 1955, or which was permitted after that date but not plugged in accordance with the act, shall plug the well to mine through it in the following manner:

(1) The gas well shall be cleaned out to a depth of at least 200 feet below the coal seam which is proposed to be mined and, unless impracticable, to a point 200 feet below the deepest mineable coal seam that the well penetrates.

(2) The gas well shall be plugged in accordance with section 13(a)(1), (2), (3) or (4) of the Coal and Gas Resource Coordination Act.

§ 78a.93. Wells in coal areas—surface or coal protective casing anchored with a packer or cement.

(a) In a well where the surface casing or coal protective casing and production casing are anchored with a packer or cement, the owner or operator shall plug the well as follows:

(1) The retrievable production casing shall be removed by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater. The well shall be filled with nonporous material from the total depth or attainable bottom of the well to a point 50 feet below the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which must extend for at least 50 feet above this stratum. Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. The cement plugs shall be placed in a manner that will completely seal the hole. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other material as approved by the Department. When the production casing is not retrievable, the operator shall plug this portion of the well under § 78a.91(d) (relating to general provisions).

(2) The well shall then be filled with nonporous material to a point approximately 200 feet below the lowest workable coal seam, or surface or coal protective casing seat, whichever is deeper. Beginning at this point a 100-foot plug of cement shall be installed.

(3) After it has been established that the surface casing or coal protective casing is free and can be retrieved, the surface or coal protective casing shall be retrieved by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of

the casing weight, whichever is greater. A string of casing with an outside diameter of at least 4 1/2 inches for gas wells, or at least 2 inches for oil wells, shall be run to the top of the 100-foot plug described in paragraph (2) and cemented to the surface.

(4) If the surface or coal protective string is not free and cannot be retrieved, it shall be perforated or cut below the lowest workable coal to allow the cement used to cement the 4 1/2-inch or 2-inch casing to communicate between the surface casing or coal protective casing, or both, and the well bore. A string of casing of at least 4 1/2 inches for gas wells or at least 2 inches for oil wells shall be run to the top of the 100-foot plug described in paragraph (2) and cemented to the surface.

(5) The inner casing shall then be emptied of liquid and cement from the base of the casing to the surface and a vent or other device approved by the Department shall be installed on the top of the casing to prevent liquids and solids from entering the well, but permit ready access to the full internal diameter of the inner casing. The inner string of casing and the vent or other device approved by the Department must extend, when finally in place, a distance of at least 72 inches above ground level and the permit or registration number must be permanently affixed to the vent.

(b) The owner or operator shall plug a well, where the surface casing and coal protective casing is anchored with a packer or cement and the production casing is cemented, as follows:

(1) If the total depth or attainable bottom is deeper than the cemented production casing seat, the operator shall plug that portion of the well under subsection (a)(1).

(2) A cement plug shall be set in the cemented portion of the production casing so that the plugs extend from at least 50 feet below each stratum bearing or having borne oil, gas or water to a point at least 100 feet above each stratum bearing or having borne, oil, gas or water. A Department approved mechanical plug may be set 20 feet above the stratum bearing or having borne oil, gas or water as a substitute for the plug of cement. Nonporous material shall separate each cement plug or mechanical plug. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials as approved by the Department.

(3) Following the plugging of the cemented portion of the production casing, the uncemented portion of the production casing shall be separated from the cemented portion and retrieved. The maximum distance the stub of the uncemented portion of the production casing may extend is 100 feet below the surface or coal protective casing whichever is lower. In no case may the uncemented portion of the casing left in the well extend through a formation bearing or having borne oil, gas or water. Other stratum above the cemented portion of the production casing bearing or having borne oil, gas or water shall be plugged by filling the hole with nonporous material to 20 feet above the stratum and setting a 50-foot plug of cement. The operator may treat multiple strata as one stratum and plug as described in this paragraph with a single column of cement or other material approved by the Department. When the uncemented portion of the production casing is not retrievable, the operator shall plug that portion of the well under § 78a.91(d).

(4) The well shall be filled with nonporous material to a point approximately 300 feet below the bottom of the

surface casing or coal protective casing, whichever is deeper. In this case, a 100-foot plug of cement shall then be placed in the well beginning at that point and extending to a point approximately 200 feet below the bottom of the casing seat.

(5) After it has been established that the surface casing or coal protective casing is free and can be retrieved, the surface or coal protective casing shall be retrieved and a string of casing with an outside diameter of not less than 4 1/2 inches for gas wells, or not less than 2 inches for oil wells, shall be run to the top of the 100-foot plug described in paragraph (4) and cemented to the surface.

(6) If the surface or coal protective string is not free and cannot be retrieved, it shall be perforated or cut below the lowest workable coal seam to allow the cement used to cement the 4 1/2-inch or 2-inch casing to communicate between the surface casing or coal protective casing, or both, and the well bore. A string of casing of not less than 4 1/2 inches for gas wells or not less than 2 inches for oil wells shall be run to the top of the 100-foot plug described in paragraph (4) and cemented to the surface.

(7) The inner casing shall then be emptied of liquid and cement from the base of the casing to the surface and a vent or other device approved by the Department shall be installed on the top of the casing to prevent liquids and solids from entering the well, but permit ready access to the full internal diameter of the inner casing. The inner string of casing and the vent or other device approved by the Department shall extend, when finally in place, a distance of not less than 72 inches above ground level and the permit or registration number shall be permanently affixed to the vent.

(c) A person authorized by the Department under the act or section 13 of the Coal and Gas Resource Coordination Act (58 P.S. § 513) to plug a gas well that penetrates a workable coal seam which was drilled prior to November 30, 1955, or which was permitted after that date but not plugged in accordance with the act shall plug the well to mine through it in the following manner:

(1) The gas well shall be cleaned out to a depth of at least 200 feet below the coal seam which is proposed to be mined and, unless impracticable, to a point 200 feet below the deepest minable coal seam which the well penetrates.

(2) The well shall be plugged in accordance with section 13(a)(2) or (4) of the Coal and Gas Resource Coordination Act.

§ 78a.94. Wells in noncoal areas—surface casing is not cemented or not present.

(a) The owner or operator shall plug a noncoal well, where the surface casing and production casing are not cemented, or is not present as follows:

(1) The retrievable production casing shall be removed by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater. The well shall be filled with nonporous material from the total depth or attainable bottom of the well to a point 50 feet below the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which must extend for at least 50 feet above this stratum.

Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. The cement plugs shall be placed in a manner that will completely seal the hole. The operator may treat multiple strata as one stratum and plug as described in this paragraph with a single column of cement or other materials as approved by the Department. When the production casing is not retrievable, the operator shall plug this portion of the well under § 78a.91(d) (relating to general provisions).

(2) After plugging strata bearing or having borne oil, gas or water, the well shall be filled with nonporous material to approximately 100 feet below the surface casing seat and there shall be placed another plug of cement or other equally nonporous material approved by the Department extending at least 50 feet above that point.

(3) After setting the uppermost 50-foot plug, the retrievable surface casing shall be removed by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater. The hole shall be filled from the top of the 50-foot plug to the surface with nonporous material other than gel. If the surface casing is not retrievable, the hole shall be filled from the top of the 50-foot plug to the surface with a noncementing material.

(b) The owner or operator shall plug a well, where the surface casing is not cemented or not present, and the production casing is cemented as follows:

(1) If the total depth or attainable bottom is deeper than the cemented production casing seat, the operator shall plug that portion of the well under subsection (a)(1).

(2) Cement plugs shall be set in the cemented portion of the production casing so that each plug extends from at least 50 feet below each stratum bearing or having borne oil, gas or water to a point at least 100 feet above each stratum. A Department-approved mechanical plug may be used as a substitute for the plug of cement. The mechanical plug shall be set 20 feet above each stratum having borne oil, gas or water. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other material approved by the Department.

(3) Following the plugging of the cemented portion of the production casing, the uncemented portion of the production string shall be separated from the cemented portion and retrieved. The maximum distance the stub of the uncemented portion of the production casing may extend is 100 feet below the surface casing. In no case may the uncemented portion of the production casing left in the hole extend through stratum bearing or having borne oil, gas or water. Other stratum bearing or having borne oil, gas or water shall be plugged by filling the hole with nonporous material to 20 feet above the stratum and setting a 50-foot plug of cement. When the uncemented portion of the production casing is not retrievable, the operator shall plug that portion of the well under § 78a.91(d).

(4) The remainder of the well shall be plugged under subsection (a)(2) and (3).

§ 78a.95. Wells in noncoal areas—surface casing is cemented.

(a) The owner or operator shall plug a well, where the surface casing is cemented and the production casing is not cemented or not present, as follows:

(1) The retrievable production casing shall be removed by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120%, whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120% of the casing weight, whichever is greater. The well shall be filled with nonporous material from the total depth or attainable bottom of the well to a point 50 feet below the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which extends for at least 50 feet above this stratum. Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. The cement plugs shall be placed in a manner that will completely seal the hole. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials as approved by the Department. When the production casing is not retrievable, the operator shall plug this portion of the well under § 78a.91(d) (relating to general provisions).

(2) After plugging all strata bearing or having borne oil, gas or water, the well shall be filled with nonporous material to approximately 100 feet below the surface casing seat. Another plug of cement, or other equally nonporous material approved by the Department, shall be placed extending at least 50 feet above that point.

(3) After setting the 50-foot plug, the hole shall be filled from the top of the 50-foot plug to the surface with a noncementing material or the operator shall set a 100-foot cement plug which extends 50-feet into the surface casing and fill the hole to the surface with noncementing material.

(b) The owner or operator shall plug a noncoal well, where the surface casing and production casing are cemented, as follows:

(1) If the total depth or attainable bottom is deeper than the cemented production casing seat, the operator shall plug that portion of the well under subsection (a)(1).

(2) Cement plugs shall be set in the cemented portion of the production casing so that each plug extends from at least 50 feet below each stratum bearing or having borne oil, gas or water to a point at least 100 feet above the stratum. A Department-approved mechanical plug may be used as a substitute for the plug of cement. The mechanical plug shall be set 20 feet above each stratum having borne oil, gas or water. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials approved by the Department.

(3) Following the plugging of the cemented portion of the production casing, the uncemented portion of the production string shall be separated from the cemented portion and retrieved. The maximum distance the stub of the uncemented portion of the production casing may extend is 100 feet below the surface casing. In no case may the uncemented portion of the production casing left

in the hole extend through stratum bearing or having borne oil, gas or water. Other stratum bearing or having borne oil, gas or water shall be plugged by filling the hole with nonporous material to 20 feet above the stratum and setting a 50-foot plug of cement. When the uncemented portion of the production casing is not retrievable, the operator shall plug that portion of the well under § 78a.91(d).

(4) The remainder of the well shall be plugged under subsection (a)(2) and (3).

§ 78a.96. Marking the location of a plugged well.

Upon the completion of plugging or replugging a well, the operator shall erect over the plugged well a permanent marker of concrete, metal, plastic or equally durable material. The marker must extend at least 4 feet above the ground surface and enough below the surface to make the marker permanent. Cement may be used to hold the marker in place provided the cement does not prevent inspection of the adequacy of the well plugging. The permit or registration number shall be stamped or cast or otherwise permanently affixed to the marker. In lieu of placing the marker above the ground surface, the marker may be buried below plow depth and shall contain enough metal to be detected at the surface by conventional metal detectors.

§ 78a.97. Plugging a well stimulated with explosives.

Where strata bearing or having borne oil, gas or water in the well have been stimulated with explosives, thereby creating cavities which cannot be readily filled as described in §§ 78a.92—78a.95, the well operator shall place at the nearest suitable point, but at least 20 feet above the stratum, a plug of cement which extends at least 50 feet above that point. If the stimulation has been done above one or more strata bearing or having borne oil, gas or water in the well, plugging in the applicable manner specified in §§ 78a.92—78a.95 shall be done at the nearest suitable points, to at least 20 feet below and at least 20 feet above the stratum stimulated. From a point immediately above and below these plugs, the well shall be plugged under §§ 78a.94 and 78a.95 (relating to wells in noncoal areas—surface casing is not cemented or not present; and wells in noncoal areas—surface casing is cemented).

§ 78a.98. Restricting surface water from the well bore.

When casing, including conductor pipe, is left in the well at the surface, the area between the casings or the casing and the well bore shall be permanently filled to the surface with a nonporous material to restrict surface water from the well bore.

INACTIVE STATUS

§ 78a.101. General provisions.

Upon application, the Department will grant inactive status for 5 years for a permitted or registered well if the application meets the requirements of section 3214 of the act (relating to inactive status) and §§ 78a.102—78a.105. The Department may require information to demonstrate that the conditions imposed by § 78a.102 (relating to criteria for approval of inactive status) are satisfied.

§ 78a.102. Criteria for approval of inactive status.

To obtain inactive status, the applicant shall affirmatively demonstrate to the Department's satisfaction that:

- (1) The condition of the well is sufficient to:
 - (i) Prevent damage to the producing zone or contamination of fresh water or other natural resources or surface leakage of substances.
 - (ii) Stop the vertical flow of fluid or gas within the well bore.
 - (iii) Protect fresh groundwater.
 - (iv) Pose no threat to the health and safety of persons, property or the environment.
- (2) The well complies with one of the following:
 - (i) The well meets casing and cementing requirements of §§ 78a.81—78a.83, 78a.83a, 78a.83b, 78a.83c and 78a.84—78a.86.
 - (ii) For wells not drilled in conformance with casing and cementing requirements of §§ 78a.81—78a.83, 78a.83a, 78a.83b, 78a.83c and 78a.84—78a.86, and for the purpose of the annual monitoring of wells granted inactive status as required under § 78a.103 (relating to annual monitoring of inactive wells), the applicant demonstrates that:

(A) For oil and gas wells equipped with surface casing, the operator shall demonstrate that the liquid level in the well bore is maintained at a level at no higher than the water protection depth. For purposes of this clause where oil or gas bearing formations are encountered less than 100 feet below the surface casing seat, the water protection depth shall be that point midway between the top of the oil or gas bearing formation and the surface casing seat.

(B) If the liquid level in an oil or gas well equipped with surface casing stands above the water protection depth and below the groundwater table depth, the operator shall test the liquid to determine its quality. If the liquid has a total dissolved solids content or conductivity generally equivalent to fresh groundwater in the immediate area, the casing is assumed to be either leaking or not set deep enough to shut off groundwater, and mechanical integrity is not demonstrated and inactive status will not be granted unless the operator demonstrates that the well is in compliance with the shut-in portion of the mechanical integrity test requirements of the Under Ground Injection Control program under the Safe Drinking Water Act (42 U.S.C.A. §§ 300f—300j-26). If the liquid has a total dissolved solids content or conductivity equivalent to the production formation or production liquid, mechanical integrity is considered to be demonstrated.

(C) For oil wells not equipped with surface casing or for oil wells equipped with surface casing that cannot be approved for inactive status under clause (A) or (B), the operator shall modify the well to meet one of the following:

(I) The operator shall set a string of casing on a packer sufficiently deep to isolate the fresh groundwater system. The casing shall be set to the water protection depth for wells in the area, and the requirements of clause (A) or (B) shall be met.

(II) The operator has set a temporary plug or mechanical seal at the water protection depth and isolated the fresh groundwater system. The operator may demonstrate the integrity of the plug by demonstrating that water standing above the plug is, and continues to be, fresh

water not contaminated by production fluids, or by other means acceptable to the Department.

(III) The operator shall fill the well with a freshwater bentonite gel or other material approved by the Department which will restrict vertical migration of gas or fluids in the well bore. The operator shall monitor the gel level and report significant changes to the Department on an annual basis and take remedial action approved by the Department.

(D) For gas wells equipped with production casing separate from the surface casing, the annulus between the surface or coal protective casing and the production casing is vented to the atmosphere. The owner or operator of a well granted inactive status under this clause shall monitor the annular vents for gas flow volumes. If the gas flow volume exceeds 5,000 cubic feet per day, the owner or operator shall notify the Department and take remedial action approved by the Department.

(E) For gas wells not equipped with separate production casing, but with cemented or uncemented surface casing present, the produced gas shut-in pressure is less than the pressure necessary to cause gas migration into the adjacent formation at the surface casing seat. Compliance with this condition may be demonstrated by mechanical tests of the casing and by evidence that the gas wellhead shut-in pressure does not exceed 0.433 psi per foot of surface or coal protective casing depth.

(3) If gas exists at an inactive oil well, the operator may vent the gas to the atmosphere or equip the well to confine the gas to the producing formation. If this gas flow is greater than 5,000 cubic feet per day, the owner or operator shall notify the Department and take remedial action approved by the Department.

(4) The applicant shall certify that the well is of future utility and shall present a viable plan for utilizing the well within a reasonable time. In addition to providing information to demonstrate compliance with paragraphs (1) and (2), the application for inactive status must include the following:

- (i) A plan showing when the well will be used.
- (ii) A certification identifying that one of the following applies:
 - (A) Significant reserves remain in place and the operator plans to produce the well.
 - (B) The well will be used as a disposal well.
 - (C) The well will be used as a storage well.
 - (D) The well will be used as an observation well.
 - (E) The well will be used as a secondary or tertiary recovery injection well or that the well will be used for other purposes specified by the applicant.

(iii) Other information necessary for the Department to make a determination on inactive status.

§ 78a.103. Annual monitoring of inactive wells.

The owner or operator of a well granted inactive status shall monitor the integrity of the well on an annual basis and shall report the results to the Department. The owner or operator shall give the Department 3 business days prior notice of the annual monitoring and mechanical integrity testing. For wells that were drilled in accordance with the casing and cementing standards of §§ 78a.81—78a.83, 78a.83a, 78a.83b, 78a.83c and 78a.84—78a.86, the operator shall monitor the integrity of the well by using the method described in § 78a.102(2)(ii)(A), (B), (D) or (E) (relating to criteria for

approval of inactive status), as appropriate. For a well that was not drilled in accordance with the casing and cementing standards, the wells shall be monitored in accordance with § 78a.102(1). To qualify for continued inactive status, the owner or operator shall demonstrate, by the data in the monitoring reports, that the condition of the well continues to satisfy the requirements of § 78a.102. The owner or operator shall submit the report by March 31 of the following year.

§ 78a.104. Term of inactive status.

Approval of inactive status for a well is valid for 5 years unless revoked. After 5 years, the owner or operator shall plug or return to active status a well granted inactive status unless the Department grants an application for a 1-year extension. The operator of a well granted inactive status may apply for renewal of inactive status by demonstrating that the well continues to satisfy the conditions imposed on the well by §§ 78a.102 and 78a.103 (relating to criteria for approval of inactive status; and annual monitoring of inactive wells).

§ 78a.105. Revocation of inactive status.

The Department may revoke inactive status and may order the immediate plugging of a well if one of the following applies:

(1) The well is in violation of the act or regulations administered by the Department.

(2) The operator of the inactive well has become insolvent, to the extent that the plan provided under § 78a.102 (relating to criteria for approval of inactive status) is no longer viable to return the well to active status, or the operator otherwise demonstrates a lack of ability or intention to comply with applicable laws and regulations.

(3) The condition of the well no longer satisfies the requirements of section 3214 of the act (relating to inactive status) and § 78a.102 and §§ 78a.103 and 78a.104 (relating to annual monitoring of inactive wells; and term of inactive status).

(4) The owner or operator is unwilling or unable to perform his obligations under the act.

RADIOACTIVE LOGGING SOURCES

§ 78a.111. Abandonment.

(a) The owner or operator may not abandon a radioactive source licensed by the Commonwealth for logging purposes without consent of the Department. Approval of a plan of abandonment may be arranged with the Department by telephone and is to be followed by a written report to the Department within 30 days after abandonment of the radioactive source. The plan shall be approved by the Department.

(b) The operator shall notify the Department of his intention to leave a radioactive source in a well.

(c) The operator shall mechanically equip a well in which a radioactive source is abandoned to prevent the accidental or intentional mechanical disintegration of the radioactive source.

(1) The operator shall cover the radioactive source being abandoned in the bottom of a well with a substantial standard color-dyed cement plug on top of which a mechanical stop or deflector shall be set. The dye must contrast with the color of the formation to alert a re-entry operator prior to encountering the source.

(2) In a well where a logging source has been cemented in place behind a casing string and above total depth,

upon plugging the well, a color-dyed cement plug shall be placed opposite the abandoned source inside the well bore and a mechanical stop or deflector shall be placed on top of the plug.

(3) If, after expending a reasonable effort, the operator cannot comply with paragraph (1) or (2) because of hole conditions, the operator shall request Department approval to cease efforts to comply with paragraph (1) or (2) and shall obtain approval for an alternate method for abandoning the source and plugging the well.

(d) Upon plugging a well in which a radioactive source is left in the hole, the operator shall place a permanent plaque by welding, bolting or cementing it to the top of the bore hole in a manner approved by the Department that re-entry cannot be accomplished without disturbing the plaque. The plaque shall serve as a visual warning to a person re-entering the hole that a radioactive source has been abandoned in-place in the well. The plaque shall depict the trefoil radiation symbol with the words "Caution, Radioactive Material" under 10 CFR 20.1901(a) (relating to caution signs) and must be constructed of a long-lasting material such as monel, stainless steel, bronze or brass. The marker must bear the following information:

- (1) Farm name.
- (2) Permit number.
- (3) Name and address of operator.
- (4) The type and strength of radioactive material abandoned in the well.
- (5) The total well depth.
- (6) Depth at which the source was abandoned.
- (7) A warning not to drill below the plug-back depth or to enlarge the casing.
- (8) The date the source was abandoned.

(e) Prior to workover or re-entry activity, if a radioactive source is present, the operator shall have the plan of operation approved by the Department before the workover or re-entry is permitted.

(f) This section does not relieve the licensee, owner or operator from the obligation to comply with Federal regulations and this title, including Chapters 225 and 226 (relating to radiation safety requirements for industrial radiographic operations; and licenses and radiation safety requirements for well logging).

Subchapter E. WELL REPORTING

- Sec.
- 78a.121. Production reporting.
- 78a.122. Well record and completion report.
- 78a.123. Logs and additional data.
- 78a.124. Certificate of plugging.

§ 78a.121. Production reporting.

(a) Each operator of an unconventional well shall submit a monthly production and status report for each well on an individual basis within 45 calendar days of the close of each monthly reporting period. Production shall be reported for the preceding reporting period. When the production data is not available to the operator on a well basis, the operator shall report production on the most well-specific basis available.

(b) The monthly production report must include information on the amount and type of waste produced and the method of waste disposal or reuse, including the specific facility or well site where the waste was managed. Waste information submitted to the Department in

accordance with this subsection is deemed to satisfy the residual waste biennial reporting requirements of § 287.52 (relating to biennial report).

(c) The production report shall be submitted electronically to the Department through its web site.

§ 78a.122. Well record and completion report.

(a) For each well that is drilled or altered, the operator shall keep a detailed drillers log at the well site available for inspection until drilling is completed. Within 30 calendar days of cessation of drilling or altering a well, the well operator shall submit a well record to the Department on a form provided by the Department that includes the following information:

(1) Name, address and telephone number of the permittee.

(2) Permit number, and farm name and number.

(3) Township and county.

(4) Date drilling started and completed.

(5) Method of drilling.

(6) Size and depth of conductor pipe, surface casing, coal protective casing, intermediate casing, production casing and borehole.

(7) Type and amount of cement and results of cementing procedures.

(8) Elevation and total depth.

(9) Drillers log that includes the name and depth of formations from the surface to total depth, depth of oil and gas producing zone, depth of fresh water and brines and source of information.

(10) Certification by the operator that the well has been constructed in accordance with this chapter and any permit conditions imposed by the Department.

(11) Whether methane was encountered other than in a target formation.

(12) The country of origin and manufacture of tubular steel products used in the construction of the well.

(13) The borrow pit used for well site development, if any.

(14) Other information required by the Department.

(b) Within 30 calendar days after completion of the well, when the well is capable of production, the well operator shall arrange for the submission of a completion report to the Department on a form provided by the Department that includes the following information:

(1) Name, address and telephone number of the permittee.

(2) Name, address and telephone number of the service companies.

(3) Permit number, and farm name and number.

(4) Township and county.

(5) Perforation record.

(6) Stimulation record which includes the following:

(i) A descriptive list of the chemical additives in the stimulation fluid, including any acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor and surfactant.

(ii) The percent by mass of each chemical additive in the stimulation fluid.

(iii) The trade name, vendor and a brief descriptor of the intended use or function of each chemical additive in the stimulation fluid.

(iv) A list of the chemicals intentionally added to the stimulation fluid, by name and chemical abstract service number.

(v) The maximum concentration, in percent by mass, of each chemical intentionally added to the stimulation fluid.

(vi) The total volume of the base fluid.

(vii) A list of water sources used under an approved WMP and the volume of water used from each source.

(viii) The total volume of recycled water used.

(ix) The pump rate and pressure used in the well.

(7) Actual open flow production and shut in surface pressure.

(8) Open flow production and shut in surface pressure, measured 24 hours after completion.

(9) The well development impoundment, if any, used in the development of the well.

(10) Certification by the operator that the monitoring plan required under § 78a.52a (relating to area of review) was conducted as outlined in the area of review report.

(c) When the well operator submits a stimulation record, it may designate specific portions of the stimulation record as containing a trade secret or confidential proprietary information. The Department will prevent disclosure of the designated confidential information to the extent permitted under the Right-to-Know Law (65 P.S. §§ 67.101—67.3104) or other applicable State law.

(d) The well record required under subsection (a) and the completion report required under subsection (b) shall be submitted electronically to the Department through the Department's web site.

§ 78a.123. Logs and additional data.

(a) The well operator shall, within 90 days of completion or recompletion of drilling, submit a copy of any electrical, radioactive or other standard industry logs which have been run.

(b) In addition, if requested by the Department within 1 year of the completion or recompletion of drilling, the well operator shall file with the Department a copy of the drill stem test charts, formation water analysis, porosity, permeability or fluid saturation measurements, core analysis and lithologic log or sample description or other similar data as compiled. Information is not required unless the operator has had the information described in this subsection compiled in the ordinary course of business. Interpretation of the data is not required to be filed.

(c) Upon notification by the Department prior to drilling, the well operator shall collect additional data specified by the Department, such as representative drill cuttings and samples from cores taken, and other geological information that the operator can reasonably compile. Interpretation of the data is not required to be filed.

(d) Data requested by the Department under subsections (b) and (c) shall be retained by the well operator and filed with the Department no more than 3 years after completion of the well. Upon request for good cause, the Department may extend the deadline up to 5 years from the date of completion or recompletion of drilling the well. The Department may request submission of the informa-

tion before these time frames if the information is necessary to conduct an investigation or for enforcement proceedings.

(e) The Department is entitled to utilize information collected under this section in enforcement proceedings, in making designations or determinations under section 1927-A of The Administrative Code of 1929 (71 P.S. § 510-27), and in aggregate form for statistical purposes.

§ 78a.124. Certificate of plugging.

(a) Within 30 calendar days after the well has been plugged, the owner or operator of the well shall submit a certificate of plugging to the Department and each coal operator, lessee or owner who was sent notice by certified mail of the intent to plug the well.

(b) The certificate of plugging must be on a form provided by the Department and contain information required by the Department.

(c) The certificate of plugging shall be prepared and signed by two experienced and qualified people who participated in the work, and shall also be signed by the well owner or operator.

Subchapter G. BONDING REQUIREMENTS

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§ 78a.301. Scope.

In addition to the requirements of section 3225 of the act (relating to bonding), this subchapter specifies certain requirements for surety bonds, collateral bonds, replacement of existing bonds, maintaining adequate bond and bond forfeiture.

§ 78a.302. Requirement to file a bond.

For a well that has not been plugged, the owner or operator shall file a bond or otherwise comply with the bonding requirements of section 3225 of the act (relating to bonding) and this chapter. A bond or bond substitute is not required for a well drilled before April 18, 1985.

§ 78a.303. Form, terms and conditions of the bond.

(a) The following types of security are approvable:

(1) A surety bond as provided in § 78a.304 (relating to terms and conditions for surety bonds).

(2) A collateral bond as provided in §§ 78a.305—78a.308.

(b) A person submitting a bond shall comply with the Department guidelines establishing minimum criteria for execution and completion of the bond forms and related documents.

(c) A bond shall be conditioned upon compliance with the drilling, water supply replacement, restoration and plugging requirements in the act, this chapter and permit conditions relating thereto. The bonds are penal in nature and are designed to ensure compliance by the operator to protect the environment, public health and safety affected by the oil and gas well.

(d) The person named in the bond or other security shall be the same as the person named in the permit.

§ 78a.304. Terms and conditions for surety bonds.

(a) The bond of a surety company that has failed, refused or unduly delayed to pay, in full, on a forfeited surety bond is not approvable.

(b) Only the bond of a surety authorized to do business in this Commonwealth is approvable. If the principal place of business of the surety is outside of this Commonwealth, or if the surety is not a Pennsylvania corporation, the surety bond shall also be signed by an authorized resident agency of the surety that maintains an office in this Commonwealth.

(c) The surety may cancel the bond by filing written notice of cancellation with the Department, the operator and the principal on the bond, only under the following conditions:

(1) The notice of cancellation shall be sent by certified mail, return receipt requested. Cancellation may not take effect until 120 days after receipt of the notice of cancellation by the Department, the operator and the principal on the bond as evidenced by return receipts.

(2) Within 30 days after receipt of a notice of cancellation, the operator shall provide the Department with a replacement bond under § 78a.310 (relating to replacement of existing bond).

(d) The Department will not accept surety bonds from a surety company when the total bond liability to the Department on the bonds filed by the operator, the principal and related parties exceeds the surety company's single risk limit as provided by The Insurance Company Law of 1921 (40 P.S. §§ 341—991.2610).

(e) The bond must provide that the surety and the principal shall be jointly and severally liable for payment of the bond amount.

(f) The bond must provide that the amount shall be confessed to judgment and execution upon forfeiture.

(g) The Department will retain, during the term of the bond, and upon forfeiture of the bond, a property interest in the surety's guarantee of payment under the bond which is not affected by the bankruptcy, insolvency or other financial incapacity of the operator or principal on the bond.

(h) The surety shall give written notice to the Department, if permissible under law, to the principal and the Department within 10 days of a notice received or action filed by or with a regulatory agency or court having jurisdiction over the surety alleging one of the following:

(1) The insolvency or bankruptcy of the surety.

(2) A violation of regulatory requirements applicable to the surety, when as a result of the violation, suspension or revocation of the surety's license to do business in this Commonwealth or another state is under consideration by a regulatory agency.

§ 78a.305. Terms and conditions for collateral bonds—general.

(a) Collateral documents shall be executed by the owner or operator.

(b) The market value of collateral deposited shall be at least equal to the required bond amount with the exception of United States Treasury Zero Coupon Bonds which

shall have a maturity date of not more than 10 years after the date of purchase and at maturity a value of at least \$25,000.

(c) Collateral shall be pledged and assigned to the Department free from claims or rights. The pledge or assignment shall vest in the Department a property interest in the collateral which shall remain until release as provided by law and is not affected by the bankruptcy, insolvency or other financial incapacity of the operator.

(d) The Department's ownership rights to deposited collateral shall be such that the collateral is readily available to the Department upon forfeiture. The Department may require proof of ownership and other means, such as secondary agreements, as it deems necessary to meet the requirements of this subchapter. If the Department determines that deposited collateral does not meet the requirements of this subchapter, it may take action under the law to protect its interest in the collateral.

§ 78a.306. Collateral bonds—letters of credit.

(a) Letters of credit submitted as collateral for collateral bonds shall be subject to the following conditions:

(1) The letter of credit must be a standby or guarantee letter of credit issued by a Federally-insured or equivalently protected financial institution, regulated and examined by the Commonwealth or a Federal agency and authorized to do business in this Commonwealth.

(2) The letter of credit must be irrevocable and must be so designated. However, the Department may accept a letter of credit for which a limited time period is stated if the following conditions are met and are stated in the letter:

(i) The letter of credit is automatically renewable for additional time periods unless the financial institution gives at least 90 days prior written notice to both the Department and the operator of its intent to terminate the credit at the end of the current time period.

(ii) The Department has the right to draw upon the credit before the end of its time period, if the operator fails to replace the letter of credit with other acceptable means of compliance with section 3225 of the act (relating to bonding) within 30 calendar days of the financial institution's notice to terminate the credit.

(3) Letters of credit must name the Department as the beneficiary and be payable to the Department, upon demand, in part or in full, upon presentation of the Department's drafts, at sight. The Department's right to draw upon the letter of credit does not require documentary or other proof by the Department that the customer has violated the conditions of the bond, the permit or other requirements.

(4) A letter of credit is subject to 13 Pa.C.S. (relating to Uniform Commercial Code) and the latest revision of *Uniform Customs and Practices for Documentary Credits* as published in the International Chamber of Commerce Publication No. 400.

(5) The Department will not accept a letter of credit from a financial institution which has failed, refused or unduly delayed to pay, in full, on a letter of credit or a certificate of deposit previously submitted as collateral to the Department.

(6) The issuing financial institution shall waive rights of set-off or liens which it has or might have against the letter of credit.

(b) If the Department collects any amount under the letter of credit due to failure of the operator to replace the

letter of credit after demand by the Department, the Department will hold the proceeds as cash collateral as provided by this subchapter. The operator may obtain the cash collateral after he has submitted and the Department has approved a bond or other means of compliance with section 3225 of the act.

§ 78a.307. Collateral bonds—certificates of deposit.

A certificate of deposit submitted as collateral for collateral bonds is subject to the following conditions:

(1) The certificate of deposit shall be made payable to the operator and shall be assigned to the Department by the operator, in writing, as required by the Department and on forms provided by the Department. The assignment shall be recorded upon the books of the financial institution issuing the certificate.

(2) The certificate of deposit shall be issued by a Federally-insured or equivalently protected financial institution which is authorized to do business in this Commonwealth.

(3) The certificate of deposit must state that the financial institution issuing it waives rights of setoff or liens which it has or might have against the certificate.

(4) The certificate of deposit must be automatically renewable and fully assignable to the Department. Certificates of deposit must state on their face that they are automatically renewable.

(5) The operator shall submit certificates of deposit in amounts which will allow the Department to liquidate those certificates prior to maturity, upon forfeiture, for the full amount of the bond without penalty to the Department.

(6) The Department will not accept certificates of deposit from financial institutions which have failed, refused or unduly delayed to pay, in full, on certificates of deposit or letters of credit which have previously been submitted as collateral to the Department.

(7) The operator is not entitled to interest accruing after forfeiture is declared by the Department, until the forfeiture declaration is ruled invalid by a court having jurisdiction over the Department, and the ruling is final.

§ 78a.308. Collateral bonds—negotiable bonds.

Negotiable bonds submitted and pledged as collateral for collateral bonds under section 3225(a)(3) of the act (relating to bonding) are subject to the following conditions:

(1) The Department will use the current market value of governmental securities, other than United States Treasury Zero Coupon Bonds, for the purpose of establishing the value of the securities for bond deposit.

(2) The current market value must be at least equal to the amount of the required bond.

(3) The Department may periodically evaluate the securities and may require additional amounts if the current market value is insufficient to satisfy the bond amount requirements for the oil or gas well operations.

(4) The operator may request and receive the interest accruing on governmental securities filed with the Department as the interest becomes due and payable. An operator will not receive interest accruing on governmental securities until the full amount of the bond has been accumulated. No interest may be paid for postforfeiture interest accruing during appeals and after resolution of the appeals, when the forfeiture is adjudicated, decided or settled in favor of the Commonwealth.

§ 78a.310. Replacement of existing bond.

(a) An owner or operator may replace an existing surety or collateral bond with another surety or collateral bond that satisfies the requirements of this chapter, if the liability which has accrued against the bond, the owner or operator who filed the first bond and the well operation is transferred to the replacement bond. An owner or operator may not substitute a phased deposit of collateral bond under section 3225(d) and (d.1) of the act (relating to bonding) for a valid surety bond or collateral that has been filed and approved by the Department.

(b) The Department will not release existing bonds until the operator has submitted and the Department has approved acceptable replacement bonds.

§ 78a.311. Failure to maintain adequate bond.

The permittee shall maintain a bond in an amount and with sufficient guarantee as provided by this chapter. If a surety company that had provided surety bonds, or a financial institution that had provided certificates of deposit or letters of credit for an operator enters into bankruptcy or liquidation, has its license suspended or revoked or for another reason indicates an inability or unwillingness to provide an adequate financial guarantee of the obligations under the bond, the operator shall submit a bond within 45 days of notice from the Department.

§ 78a.312. Forfeiture determination.

(a) A collateral or surety bond may be forfeited when the Department determines that the operator fails or refuses to comply with the act, this title, an order of the Department, or the terms or conditions of the permit relating to drilling, water supply replacement, plugging and site restoration.

(b) If forfeiture of the bond is required, the Department will:

(1) Send written notification by mail to the permittee, and the surety, if any, of the Department's intent to forfeit the bond and describe the grounds for forfeiture. The notification will also provide an opportunity to take remedial action or submit a schedule for taking remedial actions acceptable to the Department within 30 days of the notice of intent to forfeit, in lieu of collecting the bond.

(2) If the permittee and surety, if any, fail either to take remedial action or to submit a plan acceptable to the Department within 30 days of the notice of the intent to forfeit, the bond will be subject to forfeiture and collection up to the face amount thereof. The Department will issue a declaration to forfeit the bond.

(3) The declaration to forfeit is an action which may be appealable to the Environmental Hearing Board under section 4 of the Environmental Hearing Board Act (35 P.S. § 7514).

§ 78a.313. Incapacity of operators.

An owner or operator shall notify the Department by certified mail within 10 calendar days after the start of a voluntary or involuntary proceeding under 11 U.S.C.A. §§ 101—1532, known as the Federal Bankruptcy Act, naming the owner or operator as debtor.

§ 78a.314. Preservation of remedies.

Remedies provided or authorized by law for violation of statutes, including the act, the applicable environmental protection acts, this title, the terms and conditions of permits and orders of the Department, are expressly preserved. Nothing in this subchapter is an exclusive penalty or remedy for the violations. No action under this subchapter waives or impairs another remedy or penalty provided in law or equity.

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