NOTICE OF FINAL RULEMAKING
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 conventional oil and gas wells) and creates 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 oil and gas wells. The goal of this regulation is to set performance standards for surface activities associated with the development of oil and gas 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.

These regulations represent the first update to rules governing surface activities associated with the development of oil and gas wells since 2001. The final-form rulemaking splits the regulation into separate Chapters governing conventional well development (Chapter 78) and unconventional well development (Chapter 78a).

Major areas of the rulemaking in both Chapters 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 regulating both sides of the industry 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.

The conventional Chapter contains requirements for the proper regulation of road-spreading of brine; while the unconventional Chapter contains requirements for the containment of regulated substances; oil and gas gathering pipelines, well development pipelines and water management plans.

This order was adopted by the Board at its meeting of ________________________.

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 Nolan, 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 AT&T Relay

Service, (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This final-form rulemaking is available on the Department of Environmental Protection's (Department) web site at www.dep.pa.gov (select "Public Participation," then select "Environmental Quality Board").

C. Statutory Authority

This final-form rulemaking is being made under the authority of Sections 3202, 3215(e), 3218(a), 3218.2(a)(4), 3218.4(c), and 3274 of the 2012 Oil and Act (58 Pa.C.S. §§ 3202, 3215(e), 3218(a), 3218.2(a)(4), 3218.4(c), 3274); Section 5 of the Clean Streams Law (35 P.S. § 691.5); Section 105 of the Solid Waste Management Act (35 P.S. § 6018.105); Section 5 of the Dam Safety and Encroachments Act (32 P.S. § 693.5); Section 104 of the Pennsylvania Land Recycling and Environmental Remediation Standards Act (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 1741.1-E of the act of July 10, 2014 (P.L. 1053, No. 126) (72 P.S. § 1741.1-E); and Sections 1917-A and 1920-A of The Administrative Code of 1929 (71 P.S. §§ 510-17, 510-20).

D. Background and Summary

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

This regulation is needed to ensure that surface activities related to the development of conventional and unconventional wells are conducted in a manner that protects the health, safety, and environment of Pennsylvania citizens consistent with the environmental laws that provide authority for this final-form rulemaking. The surface activities requirements that currently exist in Subchapter C of Chapter 78 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 conventional and unconventional wells resulting from the passage of the 2012 Oil and Gas Act including, direction to promulgate specific regulations, (2) new technologies associated with extracting natural gas from unconventional formations and which are also used to develop conventional formations, (3) changes in the Department of Environmental Protection's (Department or DEP) 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) related to the potential risk of hydraulic fracturing communication.

Because oil and gas well drilling occurs in over 60% of the Commonwealth and oil and gas pipeline activities occur throughout the entire Commonwealth, all of its citizens will benefit from more robust and comprehensive regulations. The regulated community will benefit from this 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 contained in this final-form rulemaking are either a codification of current statutory or permit requirements or are already standard industry practices. As a whole, these final-form regulations 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 the final-form rulemaking where current policies and practices are codified in to regulation. This should provide significant benefits for several reasons. First, by having these policies expressed in a regulation, all parties – the public, conventional and unconventional oil and gas operators, Department staff, service companies, etc. – 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 the Commonwealth. Having these policies and practices codified into Chapters 78 and 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 such subjects abound in the final-form rulemaking:

- Sections 78.17(a) and 78a.17(a), which codify the Department's interpretation of the phrase "pursued with due diligence" in section 3211(i) of the 2012 Oil and Gas Act (58 P.S. § 3211(i));
- Sections 78.51 and 78a.51, which codify the Department's interpretation of water supply replacement quality standards under section 3218(a) of the 2012 Oil and Gas Act (58 P.S. § 3218(a));
- Section 78.55, which codifies the Department's current position regarding the development and maintenance of Preparedness, Prevention and Contingency plans for well sites;
- Sections 78.56, 78a.56, 78.57 and 78a.57, which codify the Department's current policies regarding management of oil and gas waste on well sites and the interpretation of section 3273.1(a) of the 2012 Oil and Gas Act (58 P.S. § 3273.1(a));
- Sections 78.58 and 78a.58, which codify the Department's current approval process for onsite oil and gas waste processing;
- Sections 78.59c and 78a.59c, which codify the Department's position regarding the proper regulation of offsite oil and gas waste management operations;
- Sections 78.65 and 78a.65, which codify the Department's positions relating to well site restoration under section 3216 of the 2012 Oil and Gas Act (58 P.S. § 3216) and Chapter 102;
- Sections 78.66 and 78a.66, which codify the Department's interpretation of existing requirements for reporting and remediating releases;
- Sections 78.67 and 78a.67, which codify the Department's interpretation of the borrow pit exemption outlined in section 3273.1(b) of the 2012 Oil and Gas Act (58 P.S. § 3273.1(b));
- Section 78.70, which codifies the Department's current roadspreading program approval process; and,
- Sections 78.122 and 78a.122, which codify the Department's current well record and completion report requirements, in accordance with section 3222 of the 2012 Oil and Gas Act (58 P.S. § 3222).

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 recent legislation (the Act of July 10, 2014 (P.L. 1053, No. 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 amendment to the final-form rulemaking was to clarify the different requirements for conventional and unconventional wells. The Department believes that having two completely separate regulatory 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 and § 78a.56, which contain significantly different requirements for temporary storage at conventional and unconventional well sites, respectively). In order to clearly summarize these regulations, the Department will discuss each Chapter in turn in Sections E. and F., below.

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 rulemaking. At TAB's April 12, 2011 and October 21, 2011 meetings, the Department again discussed topics to be included in this 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.

DEP met with other industry representative groups on several occasions during the development of the draft proposed rulemaking, including: the Marcellus Shale Coalition (MSC), which is mostly comprised of businesses representing unconventional drillers; the Pennsylvania Independent Oil and Gas Association (PIOGA), which represents unconventional and conventional drillers; Pennsylvania Independent Petroleum Producers (PIPP), which represents conventional oil industry, the Pennsylvania chapter of the American Petroleum Institute (API) as well as individual operators and midstream companies. In addition, the Department held regular meetings with industry representatives quarterly throughout the entire pendency of the rulemaking; the rulemaking generally and specific individual topics addressed by the rulemaking were standard agenda items at those meetings.

Local government organizations were also involved in discussions of the proposed regulation, 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 these proposed regulations 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 the rulemaking; the rulemaking generally and specific individual topics addressed by the rulemaking were standard agenda items at those meetings.

The Department also consulted with its sister state agencies during the development of the proposed and draft final-form rulemaking, including the Department of Transportation, the Department of Conservation and Natural Resources, the Fish and Boat Commission, the Game Commission and the Historical and Museum Commission.

A draft of the proposed rulemaking Annex A 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 their 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 contained in the proposed rulemaking at the 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 17-18, 2013 (Greensburg, PA) and August 14-15, 2013 (State College, PA). Participants in those meetings included associations representing both the conventional and unconventional industries, consultants, attorneys, environmental groups and members of the public.

Following publication of the rulemaking for public comment on December 14, 2013 and the close of the 90-day public comment period, the Department discussed the comments received on the proposed rulemaking as well as the draft final-form rulemaking with TAB at its June 26, 2014 meeting. At the September 25, 2014 TAB meeting, the Department discussed splitting the regulation into two individual Chapters as well as discussing significant changes to Annex A of the rulemaking, especially to the extent those changes concerned conventional operators.

In terms of the final-form rulemaking, the Department discussed the draft final-form Annex A published 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 an updated draft final-form rulemaking, 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 final-form regulation and discussed those changes with TAB members during a webinar held on September 18, 2015. Additional changes to the draft final-form rulemaking resulted from suggestions made during that webinar. The Department presented the final-form rulemaking appearing in Annex A to TAB at its October 27, 2015 meeting. On October 27 the Board voted unanimously to move the rulemaking to the Environmental Quality Board (EQB) without expressing support or disapproval and indicated they would be presenting a report on the rulemaking to the EQB. On January 6, 2016, TAB submitted a report on the final-form rulemaking to the EQB. A copy of this report is available on the Department's website or from the contact persons listed in Section B., above.

The Department also discussed the draft final-form rulemaking with the Conventional Oil and Gas Advisory Committee (COGAC) in 2015. The Department formed COGAC in March 2015 in order 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 rulemaking with COGAC on March 26, 2015. Following the close of the ANFR public comment period, the Department released an updated draft final-form rulemaking, 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 final-form regulation and discussed those changes with COGAC members during a webinar held on September 18, 2015. Additional changes to the draft final-form rulemaking resulted from suggestions made during that webinar. The Department presented the final-form rulemaking appearing in Annex A to COGAC at its October 29, 2015 meeting. At that meeting, COGAC adopted a resolution recommending EQB disapproval of the final-form rulemaking as it applied to conventional operators. At a meeting on December 22, 2015, COGAC adopted comments to the Board on the final-form rulemaking, urging disapproval. A copy of that document is available on the Department's website or from the contact persons listed in Section B., above.

E. Summary of Regulatory Requirements.

As noted in Section D., above, in response to comments and recent legislation (the Act of July 10, 2014 (P.L. 1053, No. 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). In order to clearly summarize these regulations, the Department will discuss each Chapter in turn.

As an initial matter, in both Chapters all references to the 1984 Oil and Gas Act have been updated to refer to the proper sections in the 2012 Oil and Gas Act. See, for example, §§ 78.13(a) and 78a.13(a) (relating to permit transfers). In many sections of the final-form rulemaking, there are no substantive changes but only corrections to the proper statutory citation. Only sections with substantive changes are discussed in this Order.

Additionally, there are many sections in Chapter 78a that were not amended by this final-form rulemaking, but were carried over to the new Chapter 78a from the existing Chapter 78 because they apply equally to conventional and unconventional well operations. An excellent example of both of these non-substantive changes are the well plugging sections, §§ 78.91 – 78.98 and

78a.91 – 78a.98. The only changes to these sections in either Chapter are to correct statutory citations necessitated by the passage of the 2012 Oil and Gas Act. The sections in Chapter 78 regarding plugging only appear here if there is a statutory citation that must be corrected. Because well plugging requirements apply equally to conventional and unconventional wells, however, those sections are repeated in their entirety in Chapter 78a, with proper cross-references to other sections in Chapter 78a.

1. CHAPTER 78. Conventional Oil and Gas Wells.

§ 78.1. Definitions

The final-form rulemaking contains new or revised definitions for "abandoned water well," "ABACT," "accredited laboratory," "Act 2," "anti-icing," "approximate original conditions," "barrel," "body of water," "borrow pit," "centralized impoundment," "certified mail," "common areas of a school's property," "condensate," "containment system," "de-icing," "floodplain," "freeboard," "inactive well," "limit of disturbance," "mine influenced water," "modular aboveground storage structure," "oil and gas operations," "other critical communities," "PCSM," "PCSM plan," "PPC plan," "Pennsylvania Natural Diversity Inventory—PNDI," "PNDI receipt," "pit," "playground," "pre-wetting," "process or processing," "public resource agency," "regional groundwater table," "regulated substance," "residual waste," "stormwater," "threatened or endangered species," "waters of the Commonwealth," "watercourse" "well development impoundment," "wellhead protection area," and "wetland" to reflect the final-form rulemaking requirements.

Under statutory changes in the 2012 Oil and Gas Act, this rulemaking provides new or amended definitions for "act," "building," "owner," "primary containment," "public water supply," "secondary containment," "water management plan," "water purveyor," and "well operator or operator."

Several existing definitions are also deleted from this section, including "certified laboratory," "nonvertical unconventional well," "reportable release of brine," and "vertical unconventional well."

§ 78.15. Application requirements

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

Subsection (b) references the 2012 Fiscal Code amendments (72 P.S. § 1606-E) that reset conventional oil and gas bonds to their pre-2012 Oil and Gas Act levels.

Subsection (b.1) established 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 one acre in size, the applicant must 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) enjoining the application of the setbacks in Section 3215(b) of the 2012 Oil and Gas Act. 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 (relating to erosion and sediment control). For that reason, subsection (e) is be 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 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.

§ 78.17. 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 commenced within one year of permit issuance. If drilling is commenced within one year, operators must pursue drilling "with due diligence" or the permit will expire. Subsection (a) sets that expiration at sixteen months from permit issuance unless an extension for good cause is obtained. Operators can also apply for a single two-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.

§ 78.18. Disposal and enhanced recovery well permits

Subsection (d) specifies that storage and waste processing requirements apply to disposal and enhanced recovery well sites.

§ 78.19. Permit application fee schedule

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

§ 78.51. Protection of water supplies

The amendments clarify that the presumption of liability established in 58 Pa.C.S. § 3218(c) (relating to protection of water supplies) 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 due to "drilling or alteration of the oil or gas 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 (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 is proposed to be amended to reflect this statutory language.

§ 78.52. 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 58 Pa.C.S. § 3218(d)(1)(i) 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. A copy of sample results must be provided to water users within 10 business days of receipt of the sample results.

§ 78.52a. Abandoned and orphaned well identification

Section 78.52a of the final rulemaking requires operators of gas wells or horizontal oil wells 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 for vertical oil wells is set at 500 feet. 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 must 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.

§ 78.53. Erosion and sediment control

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

§ 78.55. Control and disposal planning

Section 78.55 of final-form rulemaking requires all oil and gas well operators to develop and implement a site specific Preparedness, Prevention and Contingency (PPC) plan for oil and gas operations. This requirement clarifies existing requirements in §§ 91.34 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 where the operator finds that a PPC plan prepared for one well site is applicable to another site. Each individual plan must be analyzed prior to making such a determination. It is not the intent of this 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 rulemaking to require that all PPC plans be 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.

The amendments also provide that 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.

§ 78.56. 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 §§ 78.57 and 78.64. The equipment covered by this section must be removed in accordance with the requirements of § 78.65 within nine months of completion of drilling, accounting for the “temporary” nature of this storage.

The final-form rulemaking allows conventional operators to continue using pits for storage of wastes at well sites. Based on discussions with COGAC and comments the Department received, the final-form regulation limits conventional operators to the use of a single pit with a footprint area of under 3,000 ft^2, or a total volume of equal to less than 125,000 gallons. Larger pits or additional pits may be used but only with prior Department approval.

Paragraph (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 siting review will still be required for each modular aboveground storage structure.

The amendments establish new construction standards for pits at well sites, including liner compatibility testing, permeability of less than 1×10^{-10} cm/sec for liners, minimum thickness standards, liner seam testing, inspection requirements, notification to the Department prior to pit liner installation and a demonstration that the pit bottom is 20 inches above the seasonal high groundwater table.

§ 78.57. 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 must be reported to the Department within six months and properly closed within one year of the effective date of the regulations. Subsection (a) also codifies the Department's interpretation of the Solid Waste Management Act (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.

Subsection (f) codifies the requirement in section 3218.4(b) of the 2012 Oil and Gas Act 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. 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.

Subsections (f) and (g) codify the requirement in section 3218.4(b) of the 2012 Oil and Gas Act 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. 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 quarterly tank inspection requirement, similar to the monthly maintenance "walk-around" inspections currently required by the storage tank program (see

§§ 245.513(b)(2) (relating to preventive maintenance and housekeeping requirements) and 245.613(b) (relating to monitoring standards)).

§ 78.58. Onsite processing

This section deletes provisions regarding the approval of pits that existed prior to July 29, 1989. 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 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 upon Department approval. Subsection (b) proposes specific activities that do not require Department approval, including mixing fluids with freshwater, aerating fluids or filtering solids from fluids. Such activities must 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.

§ 78.59a. Impoundment embankments

This section contains design and construction standards for well development impoundments, including construction and stabilization requirements for embankments. The Department does not believe that such facilities are typically constructed by conventional operators, but should an operator decide to utilize such a facility, this option is available.

§ 78.59b. 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 must document the depth of the seasonal high groundwater table, and the manner that it was ascertained. Also, the rulemaking establishes that existing and new well development impoundments must be registered with the Department and need to be restored within nine 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 in well development impoundments to ensure that it will not result in pollution to waters of the Commonwealth.

§ 78.59c. Centralized impoundments

Within six months of the effective date of the rulemaking, 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) must elect to submit a closure plan to the Department or seek a permit for the facility under Subpart D, Article IX of the Department's regulations. 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 must obtain a waste permit or close the impoundment within three years of the effective date of the rulemaking. Any new proposed wastewater storage impoundments must 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.

§ 78.60. 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, paragraph (b)(7) contains limitations on discharges in proximity to watercourses or in the floodplain.

§ 78.61. 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 must be disposed of in accordance with §§ 78.62 or 78.63. The section contains limitations on disposal in proximity to watercourses or in the floodplain. For land application, paragraph (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.

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 website, 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 ten business days after completion of disposal.

The amendments to this section specify the loading and application rate for the land application of drill cuttings. Additionally, this section provides that the Department will maintain a list of approved solidifiers for the disposal of uncontaminated drill cuttings in pits. Further, this section specifies that the operator shall notify the Department prior to disposing drill cuttings under this section. Finally, paragraph (a)(3) contains limitations on disposal in proximity to watercourses or in the floodplain.

§ 78.62. Disposal of residual waste—pits

In accordance with section 3273.1(a) of the 2012 Oil and Gas Act, this section allows for residual waste, including contaminated drill cuttings, to be disposed of in a pit on a conventional well site. The amendments require the operator to notify the Department prior to disposing residual waste. This section also requires operators to determine that the pit bottom is 20 inches above the seasonal high groundwater table prior to using the pit and that the determination be certified by a soil scientist or other similarly trained person using accepted and documented scientific methods. Compliance with this section shall be documented and made available to the Department upon request, as well as submitted in the well site restoration report. Paragraph (a)(5) requires notice to the Department prior to disposal of the waste, and notice to the surface landowner of the location and nature of the disposal within ten business days after completion of disposal. Finally, paragraph (a)(7) contains limitations on disposal in proximity to watercourses or in the floodplain.

§ 78.63. Disposal of residual waste—land application

In accordance with section 3273.1(a) of the 2012 Oil and Gas Act, this section allows for residual waste, including contaminated drill cuttings, to be disposed of through land application on a conventional well site. Paragraph (a)(5) requires notice to the Department prior to disposal of the waste, and notice to the surface landowner of the location and nature of the disposal within ten business days after completion of disposal. Compliance with this section shall be documented and made available to the Department upon request, as well as submitted in the well site restoration report.

§ 78.64. Secondary containment around oil and condensate tanks

This section reflects federal spill prevention, control and countermeasure requirements under the Oil Pollution Act, 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 repair or within two years of the effective date of the rulemaking, whichever is sooner.

§ 78.65. 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 78.65(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.

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 timeframe 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 must be restored within nine 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) and therefore must meet the requirements, inter alia, 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.

Operators do not need to develop written restoration plans for all well sites and the 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 must be provided to the Department and the surface landowner. Waste disposal information must be included in the site restoration report,

Finally, 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 paragraphs (a) and (b)(2)-(7) and all PCSM requirements in Chapter 102.

§ 78.66. Reporting and remediating releases

The provisions in this section clarify 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 must be reported to the Department: (1) A spill or release of a regulated substance causing or threatening pollution of the waters of this Commonwealth, in the manner required by § 91.33; 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. Such reports must be made by telephone as soon as practicable but no later than two hours after the spill or release was discovered. The regulation 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.

The regulation also clarifies that the operator or responsible party shall remediate an area affected by a spill or release and outlines two different remediation options. For 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 must be remediated to demonstrate attainment of an Act 2 cleanup standard in accordance with the process outlined in subsection (c).

§ 78.67. 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. That section 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, or a regulation promulgated under the Noncoal Surface Mining Conservation and Reclamation Act, 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 Act or registered under section 3213 of the Act and meeting any applicable bonding requirements for wells serviced by the borrow pit. Also, well owners and operators must 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 within 60 days of the effective date of the regulations. Subsection (d) requires an inspection of any existing borrow pits within 180 days of the effective date of the regulation and proper restoration or upgrade within one year for any substandard borrow pits.

The section also requires borrow pit restoration or permitting under the Noncoal Surface Mining Conservation and Reclamation Act within nine months after completion of drilling the final well on a well site serviced by the borrow pit or nine months after the expiration of all well permits on well sites serviced by the borrow pit, whichever occurs later in time.

§ 78.70. Road-spreading of brine for dust control and road stabilization

This section establishes requirements regarding road-spreading of brine from conventional oil and gas wells for dust suppression and road stabilization. The rulemaking codifies Department practice regarding road-spreading of brine as previously expressed in the Department's 1998 technical guidance document *Approval of Brine Roadspreading Plans* (Doc. No.550-2100-007). This document describes to operators and other users how the Department will review all plans for the beneficial use of brine for dust control and road stabilization to ensure compliance with applicable statutes and regulations and protecting water resources.

The final-form rulemaking establishes that use of brine for dust suppression and road stabilization shall only be conducted under an annual plan approved by the Department. This section further outlines planning, notification, operation, performance, reporting and recordkeeping requirements. Additionally, the section establishes sampling procedures of brine sources and recordkeeping requirements for the analytical evaluations as well as monthly reporting requirements. Finally, this section specifies that activities conducted under this section are deemed to have a residual waste permit by rule.

§ 78.70a. Pre-wetting, anti-icing and de-icing

This section establishes requirements regarding road-spreading of brine from conventional oil and gas wells for pre-wetting, anti-icing and de-icing. The rulemaking codifies the general permit offered by the Department's residual waste program (WMGR064) which was in place for more than 10 years.

This section establishes that use of conventional brine for pre-wetting, anti-icing and de-icing activities shall only be conducted under an annual plan approved by the Department. This section further outlines plan requirements, operational standards, constituent concentration limits/specifications and application rates. Additionally, the section establishes sampling procedures of brine sources and recordkeeping requirements for the analytical evaluations as well as monthly reporting requirements. This section further specifies that activities conducted under this section are deemed to have a residual waste permit by rule.

§ 78.73. 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 or notches have to be notified at least 30 days prior to commencement or drilling. Orphan and abandoned wells that are vertically proximate to the stimulation perforations or notches must be monitored by the operator stimulating the well. Wells that penetrate within defined vertical separation distances in Table 2, 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 must notify the Department of any changes to wells being monitored and must take action to prevent pollution or discharges to the surface. Operators also must 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, the final-form rulemaking codifies the Department's current position that an operator that alters an abandoned and orphaned well by hydraulic fracturing must plug that well.

§ 78.121. Production reporting.

Subsection (b) requires conventional operators filing their annual waste production report to include the specific facility or well site where the waste was managed.

§ 78.122. 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, these include 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 § 78.52a was conducted as outlined in the area of review report.

§ 78.123. Logs and additional data

The final-form rulemaking changes address 2012 Oil and Gas Act requirements and clarify when industry logs and data collected during drilling activities need to submitted to the Department, either by being required (standard logs) or requested (non-standard logs and additional data requested prior to drilling).

§ 78.309. Phased deposit of collateral

This section is deleted in response to new bonding requirements in the 2012 Oil and Gas Act.

2. Chapter 78a. Unconventional wells.

§ 78a.1. Definitions

The final-form rulemaking contains new or revised definitions for "abandoned water well," "ABACT," "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," "mine influenced water," "modular aboveground storage structure," "oil and gas operations," "other critical communities," "PCSM," "PCSM plan," "PPC plan," "Pennsylvania Natural Diversity Inventory—PNDI," "PNDI receipt," "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," "water management plan—WMP," "waters of the Commonwealth," "watercourse," "well development impoundment," "well development pipeline" "wellhead protection area," and "wetland" to reflect the proposed requirements.

Under statutory changes in the 2012 Oil and Gas Act, this rulemaking provides new definitions for "Act," "owner," "public water supply," "water purveyor," "water source" and "well operator or operator."

§ 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) established 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 one acre in size, the applicant must 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) enjoining the application of the setbacks in Section 3215(b) of the 2012 Oil and Gas Act. 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 (relating to erosion and sediment control). For that reason, subsection (e) is be 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 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 commenced within one year of permit issuance. If drilling is commenced within one year, operators must pursue drilling "with due diligence" or the permit will expire. Subsection (a) sets that expiration at sixteen months from permit issuance unless an extension for good cause is obtained. Operators can also apply for a single two-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. 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 58 Pa.C.S. § 3218(c) (relating to protection of water supplies) 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 (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 58 Pa.C.S. § 3218(d)(2)(i) 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 must 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 58 Pa.C.S. § 3218(c) 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 must 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

The amendments to this section cross reference the requirements of Chapter 102. This section also specifies that best management practices 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 well sites

Section 78a.55 of final-form rulemaking requires all oil and gas well operators to develop and implement a site specific Preparedness, Prevention and Contingency (PPC) plan for oil and gas operations. This requirement clarifies existing requirements in §§ 91.34 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 where the operator finds that a PPC plan prepared for one well site is applicable to another site. Each individual plan must be analyzed prior to making such a determination. It is not the intent of this 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 rulemaking to require that all PPC plans be 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.

The amendments also provide that 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.

§ 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, 78a.64 and 78a.64a. The equipment covered by this section must be removed in accordance with the requirements of § 78a.65 within nine months of completion of drilling, accounting for the "temporary" nature of this storage.

For unconventional operators, § 78a.56 of the final-form rulemaking 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.

Paragraph (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 siting review will still be required for each modular aboveground storage structure.

The final-form rulemaking also includes new monitoring requirements 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 must be reported to the Department within six months and properly closed within one year of the effective date of the regulations. Subsection (a) also codifies the Department's interpretation of the Solid Waste Management Act (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 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. 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) (relating to preventive maintenance and housekeeping requirements) and 245.613(b) (relating to 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 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 upon Department approval. Subsection (b) proposes specific activities that do not require Department approval, including mixing fluids with freshwater, aerating fluids or filtering solids from fluids. Such activities must 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 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 must document the depth of the seasonal high groundwater table, and the manner that it was ascertained. Also, the rulemaking establishes that existing and new well development impoundments must 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 my 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 in well development impoundments to ensure that it will not result in pollution to waters of the Commonwealth.

§ 78a.59c. Centralized impoundments

Within six months of the effective date of the rulemaking, 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) must elect to submit a closure plan to the Department or seek a permit for the facility under Subpart D, Article IX of the Department's regulations. 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 must obtain a waste permit or close the impoundment within three years of the effective date of the rulemaking. Any new proposed wastewater storage impoundments must 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, paragraph (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 must be disposed of in accordance with §§ 78.62 or 78.63. The section contains limitations on disposal in proximity to watercourses or in the floodplain. For land application, paragraph (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 website, 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 ten business days after completion of disposal.

§§ 78a.62. Disposal of residual waste—pits and 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, 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 repair or within two years of the effective date of the rulemaking, whichever is sooner.

§ 78a.64a. Containment systems and practices at unconventional well sites

This proposed 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. Further, this proposed section specifies secondary containment requirements. Additionally, this section proposes 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 78.65(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.

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 timeframe 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 must be restored within nine 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) and therefore must meet the requirements, inter alia, 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.

Operators do not need to develop written restoration plans for all well sites and the 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 must be provided to the Department and the surface landowner. Waste disposal information must be included in the site restoration report, Finally, 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 paragraphs (a) and (b)(2)-(7) and all PCSM requirements in Chapter 102.

§ 78a.66. Reporting and remediating releases

The provisions in this section clarify 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 must be reported to the Department: (1) A spill or release of a regulated substance causing or threatening pollution of the waters of this Commonwealth, in the manner required by § 91.33; 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. Such reports must be made by telephone as soon as practicable but no later than two hours after the spill or release was discovered. The regulation 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.

The regulation also clarifies that the operator or responsible party shall remediate an area affected by a spill or release and outlines two different remediation options. For 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 must be remediated to demonstrate attainment of an Act 2 cleanup standard in accordance with the process outlined 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. That section 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, or a regulation promulgated under the Noncoal Surface Mining Conservation and Reclamation Act, 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 Act or registered under section 3213 of the Act and meeting any applicable bonding requirements for wells serviced by the borrow pit. Also, well owners and operators must 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 within 60 days of the effective date of the regulations. Subsection (d) requires an inspection of any existing borrow pits within 180 days of the effective date of the regulation and proper restoration or upgrade within one year for any substandard borrow pits.

The section also requires borrow pit restoration or permitting under the Noncoal Surface Mining Conservation and Reclamation Act within nine months after completion of drilling the final well on a well site serviced by the borrow pit or nine months after the expiration of all well permits on well sites serviced by the borrow pit, whichever occurs later in time.

§ 78a.68. Oil and gas gathering lines

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. The rulemaking requires equipment refueling and staging areas must be out of floodways and least fifty 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. The rulemaking requires that all buried metallic gathering pipelines shall be installed and placed in operation in accordance with federal regulations at 49 CFR Part 192, Subpart I or 195, Subpart H (relating to requirements for 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 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. 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 additive on its website and any person using one of the approved additives does not require additional approval from the Department.

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

The 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 section § 78a.68a.

§ 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.

The 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 application for construction or modification of culverts and bridges).

The 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 must 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 must be removed when the well site is restored. The rulemaking requires operators to obtain Department approval for well development pipelines in service for more than a year.

The rulemaking requires that the operator 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 a year after their removal and be made available to the Department upon request.

§ 78a.69. Water management plans

Water Management Plans are a requirement for unconventional wells in section 3211(m) of the 2012 Oil and Gas Act. This regulation 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. Further, the 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. The 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 and 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 must be notified at least 30 days prior to commencement or drilling. Orphan and abandoned wells that are vertically proximate to the stimulation perforations must 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 must notify the Department of any changes to wells being monitored and must take action to prevent pollution or discharges to the surface. Operators also must 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, the final-form rulemaking codifies the Department's current position that an operator that alters an abandoned and orphaned well by hydraulic fracturing must plug that well.

§ 78a.121. Production reporting.

The final rule requires unconventional operators to report production on a monthly basis in accordance with Section 3 of the Unconventional Well Report Act (58 P.S. § 1003). Additionally, the final rule 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 was conducted as outlined in the area of review report.

§ 78a.123. Logs and additional data

The final-form rulemaking changes address 2012 Oil and Gas Act requirements and clarify when industry logs and data collected during drilling activities need to submitted to the Department, either by being required (standard logs) or requested (non-standard logs and additional data requested prior to drilling).

§ 78a.309. Phased deposit of collateral

This section is deleted 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, commencing with *Pennsylvania Bulletin* publication on December 14, 2013 (43 *Pa.B.* 7377) and ending on March 14, 2014. The Board also held nine public hearings on the proposed rulemaking, including:

- January 9, 2014, West Chester, PA
- January 13, 2014, Williamsport, PA
- January 15, 2014, Meadville, PA
- January 16, 2014, Mechanicsburg, PA
- January 22, 2014, Washington, PA
- January 23, 2014, Indiana, PA
- January 27, 2014 Tunkhannock, PA
- February 10, 2014, Troy, PA
- February 12, 2014, 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 nine public hearings. The Independent Regulatory Review Commission (IRRC) also submitted comments on the proposed rulemaking.

Based on the review of those comments, the Department developed a draft final rulemaking and used an Advanced Notice of Final Rulemaking (ANFR) procedure on April 4, 2015 (45 *Pa.B.* 1615). 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 rulemaking including:

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

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

The major comments received on the proposed version and draft-final version of the rulemaking, and the Department's responses, are summarized below. It is worth noting at the outset that on nearly every issue raised by the proposed and final-form rulemakings 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.

Because many of the commenters did not specifically single out either the conventional or unconventional side of the industry when providing comments, the discussion below addresses both Chapters in a single section. Where comments and changes are specific to either the conventional Chapter 78 or the unconventional Chapter 78a, those comments and changes are specifically called out in the discussion.

Banning Hydraulic Fracturing

The Department received many comments on both proposed and 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 fracking within the Commonwealth. Banning hydraulic fracturing would require an act of the Legislature.

Well drilling can be done in a safe and environmentally sound way, provided applicable laws are adhered to by the regulated community. The regulatory changes included in Chapters 78 and 78a are intended to further strengthen these standards to ensure the Commonwealth's environment and the health of its citizens is properly protected. The Department believes the revisions to Chapters 78 and 78a are comprehensive, enforceable, are 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 rules as necessary.

Issues outside of the scope of the rulemaking

Similarly, the Department received many comments that were outside the scope of the rulemaking. For example, several commenters 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. While the Board does have authority to alter bond amounts through regulation, that topic was not considered in this rulemaking and so no changes were made to those sections in the final-form rulemaking. Similarly, many commenters raised air quality issues related to oil and gas operations. Air emissions from oil and gas operations are regulated under Title 25, Article III, and not Chapters 78 and 78a. Revisions to Article III are beyond the scope of this rulemaking. However, air emissions from the oil and gas sector are regulated through a series of measures including the best available technology or BAT 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 the final rule. Based on public comment to the proposed rulemaking raising concerns over noise issues at unconventional well sites, the Department developed § 78a.41 (relating to noise mitigation) to address noise issues at unconventional well sites and published that provision as part of the ANFR on April 4, 2015.

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). Because 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 in order 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 relating to noise issues will need to take those developments into account.

For these reasons, the Department has removed § 78a.41 from the final rulemaking in order 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 such 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 §§ 78.57 and 78a.57 (relating to 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 rulemaking requirements 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 rulemaking to give operators an environmentally-protective option for off-site wastewater management given the Department's decision to eliminate the use of centralized impoundments without residual waste permits in §§ 78.59c and 78a.59c of the draft final-form rulemaking. These sections were published as part of the ANFR procedure on April 4, 2015.

There was widespread opposition to these new sections across the spectrum of commenters, for various reasons. In keeping with the Department's interpretation of section 3273.1(a) of the 2012 Oil and Gas Act (58 P.S. § 3273.1(a)), and the decision to eliminate the use of centralized impoundments without residual waste permits in §§ 78.59c and 78a.59c of the draft final-form rulemaking, the Department removed §§ 78.57 and 78a.57 from the 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 (1) generated at that well site or (2) waste that will be beneficially reused at that well site, must obtain a permit to do so under the Department's residual waste regulations rather than operating under Chapters 78 or 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 our website 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, etc. Additionally, the Department has an Oil & Gas Mapping application on its website that allows users to geographically locate oil and 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 our website, and the ability to readily locate, retrieve, and export that information.

Regulatory Review Act Compliance

Commenters 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 Chapters 78 and 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 rulemaking provisions. 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 provisions. The final-form rulemaking represents the Department's revisions to the rulemaking provisions after careful consideration of all comments received during the rulemaking process and of the additional public input.

A subset of these concerns relates to forms and guidance documents necessary to implement the final-form rulemaking and lack of availability of those documents for review concurrently with review of the proposed and ANFR rulemakings. The Department will make forms and guidance documents available prior to adoption of the final rule in order to address this concern. The Department notes that forms and guidance can only be based on the performance standards and requirements established by the 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 the final-form rulemaking will be is impractical.

§§ 78.1 and 78a.1. Definitions

Several definitions were added to these sections between proposed and final rulemaking, including "abandoned water well," "ABACT," "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," "Pennsylvania Natural Diversity Inventory—PNDI," "PNDI receipt," "playground," "primary containment," "public resource agency," "residual waste," "secondary containment," "threatened or endangered species," "waters of the Commonwealth," and "wellhead protection area." These definitions were added to provide clarity to the substantive sections of the regulations or to address provisions added to the final-form rulemaking. An example of the latter category 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 §§ 78.15(f) and 78a.15(f).

Two definitions were changed between proposed and final to better reflect the substantive sections of the rulemaking and in response to comments. Definitions that were changed are "centralized impoundment" (to better reflect the changes to §§ 78.59c and 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 in § 78a.1 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 has amended the definition of "oil and gas operations" by removing those two terms.

Finally, several definitions were deleted on final rulemaking as they became unnecessary due to changes in the substantive provisions or the bifurcation of the rules into two separate Chapters. Deleted definitions include "certified laboratory," "conventional formation" (§ 78a.1); "conventional well" (§ 78a.1); "containment system," "gathering pipeline" (§ 78.1); "nonvertical unconventional well" (§ 78.1); "temporary pipelines" (§ 78.1); "vertical unconventional well" (§ 78.1); "WMP – water management plan" (§ 78.1); and "water source" (§ 78.1)

§§ 78.15 and 78a.15. Application requirements

Protecting Waters of the Commonwealth

Sections 78.15(b.1) and 78a.15(b.1) were added to the rulemaking on final. These sections establish 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 one acre in size, the applicant must 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. v. Commonwealth*, 83 A.3d 901 (Pa. 2013), 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, 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 such 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 commenters 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 Title 25 of the Pennsylvania Code and are consistent with the riparian buffer requirements in 25 Pa. Code Chapter 102.

As documented in the 2010 Chapter 102 final-form rulemaking "Erosion and Sediment Control and Stormwater Management", 40 *Pa.B.* 4861, there is substantial scientific support for a 100-foot buffer from streams. One such 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 on final 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) also changed to codify the Department's policy that PNDI clearances obtained less than two 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 rulemaking. Not surprisingly, this subsection generated significant comments across the entire spectrum of issues. The significant comments, and any changes to the final-form rulemaking language as a result of those comments, are outlined below.

Authority

The public resource impact screening process in Sections 78.15(f)-(g) and 78a.15(f)-(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, the 2012 Oil and Gas Act, the Clean Streams Law, the Dam Safety and Encroachments Act, the Solid Waste Management Act 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 statutory obligations, Sections 78.15 and 78a.15 establish 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. 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 Sections 78.15(f)(1) and 78a.15(f)(1), the well permit operator must provide additional information in the well permit application and notify applicable public resource agencies thirty days prior to submitting the well permit application. Under Sections 78.15(f)(2) and 78a.15(f)(2), the public resource agencies have thirty 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 Sections 78.15(g) and 78a.15(g). Section 78.15(g) and 78a.15(g) are added to this rulemaking 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 Environmental Quality Board to develop such criteria by regulation.

The right of the people of Pennsylvania 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 are fundamental to the quality of life of the people of Pennsylvania. 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 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 the Commonwealth.

Despite the Department's duties and obligations as described above, industry commentators argued that the Department does not have the statutory authority to promulgate regulations regarding public resources under Sections 78.15(f)-(g) and 78a.15(f)-(g) because the Pennsylvania Supreme Court enjoined Sections 3215(c) and (e) in *Robinson Twp. v. Commonwealth*, 83 A.3d 901 (Pa. 2013) (*Robinson Twp.*). The Department asserts that Sections 3215(c) and (e) were 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. Additionally, as of the date of the finalization of this document, this issue is being litigated in Commonwealth Court. *See Pennsylvania Independent Oil & Gas Association v. Commonwealth* (321 M.D. 2015). The Department's Answer reflecting its interpretation of *Robinson Twp.* will be filed before Commonwealth Court by January 30, 2016."

The Pennsylvania Supreme Court's decision in *Robinson Twp.* invalidated Sections 3215(b)(4), 3215(d), 3303 and 3304 of the 2012 Oil and Gas Act as unconstitutional. As for Sections 3215(c) and 3215(e), the 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." *Id.* at 1000 (emphasis added).

Sections 3215(b), 3215(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; preemption of local ordinances; and uniformity of local ordinances, respectively. Section 3215(c) is a separate, independent, free-standing provision that does not implement or enforce these invalidated provisions. Rather, Section 3215(c) 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). Under Section 3215(e), the Environmental Quality 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).

The Department believes that Sections 3215(c) and 3215(e) do not implement or enforce Sections 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 discussed above, the Department retains a specific statutory obligation to protect public resources under Sections 3215(c) and (e) of the 2012 Oil and Gas Act.

However, even if those paragraphs were invalidated as some commentators assert the provision under the prior law enacted in 1984 mandating protection of public resources would then remain in effect. *See* 58 P.S. § 601.205(c). Thus, the Environmental Quality Board has authority under either the 2012 revisions to the law or the prior provision enacted in 1984 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 Sections 78.15 and 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, which provides that the purpose of the act is to "[p]rotect the natural resources, environmental rights and values secured by the Constitution of Pennsylvania." 58 Pa.C.S. § 3203. Under Section 3274 of the 2012 Oil and Gas Act, the Environmental Quality Board has the authority to promulgate regulations necessary to implement the statute. The public resource protection provisions in Sections 78.15 and 78a.15 provide a reasonable and appropriate process for the Department to implement the constitutional and statutory requirements discussed above.

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 Solid Waste Management Act, the Dam Safety and Encroachment Act, the Pennsylvania Land Recycling and Environmental Remediation Standards Act 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 must coordinate with those agencies to fulfill its constitutional and statutory duties to protect public natural resources. The public resource protection provisions included in the Chapter 78 and Chapter 78a rulemaking facilitate the Department's compliance with this obligation.

Finally, the public screening requirements provided in this rulemaking establish a standardized and transparent process for the Department to identify, consider and to 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 under the most recent court decisions interpreting the 1973 *Payne v. Kassab, 312 A.2d 86 (Pa. Cmwlth. 1973)* three-part test.

The public resource protection requirements in §§ 78.15 and 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 and draft final rulemaking could be, many commenters expressed concern over the distances contained in §§ 78.15(f) and 78a.15(f). Some commenters felt that the distances should be expanded. Other 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 §§ 78.15(f)(1) and 78a.15(f)(1) of the final 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, §§ 78.15(f)(1) and 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. For conventional operations this change will have little to no practical effect given the relatively small size of these conventional sites.

Setbacks

Many commenters believed that the distances outlined in §§ 78.15(f) and 78a.15(f) comprised setbacks and that specifically there should be a one-mile setback from schools, nursing homes and day care facilities.

The provisions in this 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 commenters suggests that the General Assembly should extend these setbacks from certain facilities, such as schools, nursing homes or day care facilities, that change should 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 comments felt that even though §§ 78.15(f) and 78a.15(f) do not establish setbacks, they still gave "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 Solid Waste Management Act 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." 58 Pa.C.S. § 3203. Under Section 3274 of the 2012 Oil and Gas Act, this Board has the authority to promulgate regulations necessary to implement that statute.

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. 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 Pennsylvania Fish and Boat Commission and the Pennsylvania Game Commission have responsibility for managing various fish and wildlife resources within the 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.

Sections 78.15(f) and 78a.15(f) establish 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, the final rulemaking language 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 outlined in §§ 78.15(g) and 78a.15(g), and to determine whether permit conditions are necessary to prevent a probable harmful impact.

Public resources to be considered in§§ 78.15(f) and 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 commenters 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 3215(c) 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.

Sections 78.15(f)(1) and 78a.15(f)(1) of the final rulemaking include the public resources listed in 3215(c). 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 25 Pa. Code § 109.713 and limiting the areas to those classified as zones 1 and 2. Additionally, definitions for the terms "common areas of a school's property" and "playground" have been added to §§ 78.1 and 78a.1.

Notwithstanding the enumeration of specific public resources in the regulations, the Department will consider the potential impacts to other public resources identified during the permitting process.

To the extent that commenters questioned what constitutes an impact, §§ 78.15(f)(2)-(3) and 78a.15(f)(2)-(3) outline the process for coordinating with public resource agencies and the information that a well permit applicant must 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 §§ 78.15(g) and 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.

Such facilities have not been added to the list of public resources included in §§ 78.15(f)(1) and 78a.15(f)(1) of the 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 commenters were suggesting that additional protections are needed for these facilities, Chapters 78 and 78a, as well as other regulations, permits and policies implemented by the Department under Pennsylvania'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. Sections 78.15(f) and 78a.15(f) have not been expanded in this manner because protection of these waters is achieved through other provisions in Chapters 78 and 78a, as well as implementation of other water permitting programs administered by the Department through other environmental laws and regulations. Specifically, §§ 78.15(b.1) and 78a.15(b.1) require 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, Chapters 78 and 78a contain 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 the final-form rulemaking.

Sections 78.15 and 78a.15 establish the well permit application process and are 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 Chapters 78 and 78a, or other laws implemented by the Department.

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

Related to the provisions in §§ 78.15(f)(1)(iv) and 78a.15(f)(1)(iv), some commenters 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 Solid Waste Management Act and other statutes. Specifically, 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 the final 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 Environmental Quality Board has the authority to promulgate regulations necessary to implement the statute.

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. The final 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, the final rulemaking amends the definition of "other critical communities" in §§ 78.1 and 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 removed the provisions in the draft-final rulemaking relating to specific areas within the geographical area occupied by a threatened or endangered species and significant non-species resources. These changes were to ensure that the final-form rulemaking accurately reflects the existing PNDI process.

The process for consideration of public resources in §§ 78.15 and 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. Sections 78.15(f) and 78a.15(f) outline 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 §§ 78.15(g) and 78a.15(g).

Provisions of § 78.15(f)(1)(iv) related to other critical communities impose economic hardship to conventional operators.

A significant number of conventional operators commented that they believed the provisions of §§ 78.15(f)(1)(iv) and 78a.15(f)(1)(iv) would impose economic hardship on these operators. The Department disagrees that coordination with public resource agencies to consider impacts to other critical communities will impose an economic hardship on conventional oil and gas operators. These operators are currently required to identify the habitats of special concern species where the proposed well site or access road will be located and describe measures proposed to be taken to avoid or mitigate impacts to special concern species. The applicant must provide a PNDI receipt with the well permit application and, if a potential impact is identified, the applicant must notify the applicable public resource agency. The applicant should also be consulting with the agency to identify appropriate avoidance and/or mitigation measures. As this is an existing well permit application component necessary to comply with the statutory requirements, this final rulemaking does not impose any new financial burden.

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 suggests that additional requirements are needed for emergency response, Section 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 reference to 25 Pa. Code §109.713 and limiting public resource coordination to proposed wells in Zone 1 and Zone 2 wellhead protection areas.

Several commenters 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 the 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 on final. 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 78 and other Department regulations and statutes provide adequate protection.

Public resource agency notification and comment period

Many commenters expressed concerns over the amount of time given in §§ 78.15(f) and 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 Solid Waste Management Act 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.” 58 Pa.C.S. § 3203. Under Section 3274 of the 2012 Oil and Gas Act, this Board has the authority to promulgate regulations necessary to implement that statute. 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.

Sections 78.15(f)(2) and 78a.15(f)(2) have 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.

Sections 78.15(f) and 78a.15(f) establish 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 §§ 78.15(g) and 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 the term "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.

Sections 78.15(g) and 78a.15(g) have 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 DEP to show that permit conditions are necessary to protect against probable harms is profoundly improper.

Sections 78.15(g) and 78a.15(g) have been revised to remove the language regarding the Department's burden of proof upon appeal of a condition necessary to protect a public resource. Section 3215(e) of the 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.

Subsection (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

Sections 78.15(h) and 78a.15(h) require well permit applicants proposing to drill a well that involves one to five 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 anti-degradation requirements in Chapter 93.

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

Several commenters 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 such wells are by definition conventional wells, the Department added a cross-reference to § 78.18 to the final-form rulemaking in § 78a.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 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 Pennsylvania 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 the current rulemaking.

The Department also notes that the Commonwealth does not have primacy for the UIC program in Pennsylvania; that authority lies with EPA Region III. The EPA program regulations are authorized by the Safe Drinking Water Act and are designed to protect all underground sources of drinking water from all waste injection activities.

§§ 78.51 and 78a.51. Protection of water supplies

In the final-form rulemaking, §§ 78.51(d)(2) and 78a.51(d)(2) provide that a restored or replaced water supply will be deemed adequate if it meets the standards established under the Pennsylvania Safe Drinking Water Act (SDWA) or "is comparable to the quality of the water that existed prior to the 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 the statute as part of the 2012 Oil and Gas Act.

Many commenters argued that use of the term "exceeded" in Section 3218(a) of the 2012 Oil and Gas Act should be interpreted to describe a water supply that does not meet Pennsylvania Safe Drinking Water Act standards instead of using the term "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.

The final rulemaking requires water supplies to be restored to Pennsylvania Safe Drinking Water Act 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, must 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 regards 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 pre-drill water supply survey to help bolster their defense of what the preexisting 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.

Sections 78.51(c) and 78a.51(c) provide 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 commenters 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 twelve 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 six 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 subsection as provided in 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.

Sections 78.51(a) and 78a.51(a) specify 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 commenters argued that the Department has no authority to expand water supply pollution or diminution investigations to include oil and gas operations. While § 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 commenters have suggested the Department specifically notify neighboring land owners and/or land management agencies 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 DEP concludes that a water supply may be impacted by a spill, DEP 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 the rulemaking at this time.

Many commenters argued that the Department should lessen the 10-day time frame afforded to it in § 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 the document titled "Standards and Guidelines for Identifying, Tracking, and Resolving Oil and Gas Violations" (Document number 820-4000-001 Revised January 17, 2015).

§§ 78.52 and 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 timeframe. Subsection (d) allows an operator to rebut the presumption by proving that "the pollution existed prior to the drilling, stimulation or alteration activity as determined by a predrilling or prealteration survey…" The Department received significant public comment that the rule should include a specific list of potential contaminants that must be analyzed for in each pre-drilling or pre-alteration 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 contaminates 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 pre-drill water supply survey results.

The final rule 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 rule, operators were required to submit each individual's sample by mail as it was completed, which was much less efficient for both 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. The final rule allows all sample results pertaining to the well of concern to be submitted to the Department by the operator 10 days prior to commencement of drilling of the well in a single coordinated report. The Department believes that this change allows this portion of the regulation 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 commenters 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, in order to protect the privacy and rights of the property owners.

§§ 78.52a and 78a.52a. Area of review; and §§ 78.73 and 78a.73. General provision for well construction and operation.

Because the requirements in the new area of review sections, §§ 78.52a and 78a.52a, and the changes to the general provision for well construction and operation sections in Subchapter D, §§ 78.73 and 78a.73, 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 Pennsylvania. 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 no water supplies are 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 Pennsylvania's oil and gas program in 2010 and 2013. Although generally complementary of the Pennsylvania 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, pp 51-52. 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.

Sections 78.52a and 78a.52a of the final 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 must also be consulted.

Sections 78.73 and 78a.73 indicate which subset of the identified wells must 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.

The area of review regulation 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. Such 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. Such 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. The final 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 the 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 Pennsylvania, i.e., between 1984 and the present day. Prior to passage of the 1984 Oil and Gas Act, it is difficult to speculate at what frequency such 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 the state, 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.

The final area of review regulation, 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 Act, which intends that oil and gas wells be constructed in such a way to prevent gas and other fluids from entering sources of fresh groundwater.

§§ 78.53 and 78a.53. Erosion and sediment control

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

§§ 78.55. Control and disposal planning; and 78a.55. Control and disposal planning; emergency response for unconventional well sites.

Sections78.55 and 78a.55 of the final-form rulemaking require 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 where 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 must be analyzed prior to making such a determination. It is not the intent of this 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 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.

The Department received significant public comment from conventional oil and gas operators indicating that this requirement was excessive and overly burdensome for their operations. The commenters argued that the requirement to develop and update site specific PPC plans was unnecessary because conventional well sites are all so similar that a single plan is sufficient to address all sites. The commenters also argued that maintaining a copy of the PPC plan on the site is overly burdensome and unnecessary for conventional operators. Commenters also expressed concerns about §§ 78.55(a) and 78a.55(a) which simply reiterate the requirements already existing in §§ 91.34 and 102.5(l). Since §§ 78.55(a) and 78a.55(a) do not establish any new requirements, this subsection presents any new burden on operators, yet referencing these requirements in Chapters 78 and 78a have value in reminding operators of those obligations. Operators may develop a single integrated PPC plan to satisfy the requirements of §§ 78.55(a) and 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. The final rulemaking does not exempt the requirements of either §§ 91.34 or 102.5(l) for conventional or unconventional oil and gas activities. The purpose of §§ 78.55 and 78a.55 as they relate 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 the final rule.

It appears that the commenters 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 on site at all times. This rulemaking does not require persons to post PPC plans at these sites at all times. This 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, §§ 78.55(e) and 78a.55(e) require 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 such 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.

Sections 78.55(e) and 78a.55(e) also require 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 their jurisdiction. The Department has determined that this is reasonable and appropriate to ensure compliance with all applicable law. Additionally, the requirement to provide landowner a copy of the PPC plan upon request in needed because landowners have a vested interested 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.

§§ 78.56 and 78a.56. Temporary storage

Sections 78.56 and 78a.56 regulate 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 these provisions is to ensure that temporary storage at the well site during these activities protects public health, safety and the environment. These provisions are 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 the 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. At the same time, in § 78.56 the Department has retained the use of temporary pits for conventional operators because the typical type and scope of use by conventional operators is generally compatible with the appropriate technical standards outlined in this section. The Department has allowed the disposal of residual wastes including contaminated drill cuttings in a pit at conventional well sites for decades. When done in accordance with appropriate environmental standards, such disposal can occur without significant harm to public health and safety or the environment. Therefore, the Department has updated the standards for pits in §§ 78.56 and 78.62 and the final-form rulemaking retains pits as an option for proper temporary waste storage at conventional well sites.

In addition, in the proposed rulemaking, the Department included a requirement that temporary pits must have an inside slope 2:1 (horizontal: vertical) or flatter. The Department received significant public comment on this proposed requirement and ultimately removed the minimum slope requirement from the final-form rulemaking. Instead, the final-form rulemaking continues to allow conventional operators to construct pits with steep inside slopes provided that the pits have an aerial extent of less than 3,000 ft^2 and volumetric capacity of less than 125,000 gallons. For larger pits, the final rule requires the operator to obtain a site specific approval from the Department prior to constructing the pit. This requirement is necessary because the definition of conventional formation is very broad and technological advances may result in conventional operators utilizing large pits that are in place for a longer period of time, similar to the type and scope of use of pits by unconventional operators. The Department has determined that this type of pit use is generally incompatible with the technical standards for temporary pits prescribed under § 78.56. This revision will allow continued use of conventional pits at well sites, prevent an unnecessary increase in the footprint of pits and provide appropriate protections to the environment when operators require the use of large pits.

The final rule requires that pit liners for temporary storage have a thickness of at least 30 mils and allows for the liner manufacturer to demonstrate that a thinner liner is equally protective. Commenters indicated that a requirement to use a 30 mil liner was unnecessary and overly burdensome. Commenters argued that irrespective of cost, a 30 mil liner is 184 pounds heavier than a 20 mil liner. The Department acknowledges that 30 mil liners are heavier per unit area than 20 mil liners. Based on the best information available to the Department and assuming use of vertical walls and a high density polyethylene (HDPE) liner, a pit liner where the difference in weight between a 20 mil thickness and a 30 mil thickness is 184 lbs. has an aerial extent of approximately 3,800 ft^2 with the 20 mil liner weight being approximately 368 pounds and the 30 mil liner weight being approximately 552 lbs. The weight of a 20 mil pit liner of this size is substantial enough to require machinery and/or a multi-person crew to install. A pit of this size has been represented to the Department by the members of COGAC as the largest pit used during conventional operations in Pennsylvania. In addition, the example provided by COGAC included vertical walls that are 8 feet tall which would make installation of even a 20 mil liner very difficult without machinery or a multi-person crew. Also, conventional operators have indicated to the Department that the pits used in conventional well operations are typically no larger than 10 feet by 30 feet and hold less than 4,200 gallons. The liner required for a pit of that size is conservatively 650 ft^2 with the 20 mil liner weight being approximately 62 pounds and the 30 mil liner weight being approximately 95 pounds which is a weight difference of only 33 pounds. The Department believes that the example given by commenters is an extreme example and consequently, the Department does not believe that the example of a 184-pound weight difference is an accurate representation of the impact of a 30 mil liner requirement on the conventional oil and gas industry. The Department does not believe that an increase in weight of 33 pounds for a typical pit or 184 pounds for a very large pit is overly burdensome for conventional operators to manage.

Prior to this revision, § 78.56 did not include any specification for minimum liner thickness and only included a requirement for a "synthetic impermeable liner." However, § 78.62 (relating to disposal of residual wastes in a pit) has required the use of a 30 mil liner or an alternate material if approved by the Department since Chapter 78 was initially promulgated in 1989. The Department acknowledges that when disposing of cuttings by land application, a liner thickness is not specified, but the Department notes that disposal of cuttings in a pit is far more common than land application. The Department has approved a small but significant number of liner products with a 20 mil thickness since Chapter 78 was initially promulgated but does not believe that the exception should define the rule. Due to these existing requirements, the Department believes that conventional oil and gas operators should already be using 30 mil liners or an approved alternative most of the time. The Department has observed many operators utilizing liner materials that are thinner than 20 mils, which met the requirement of being a "synthetic impermeable liner" but were not robust enough to remain impermeable during typical use as a pit liner. The final rule eliminates use of liner materials that are known to not be robust enough to provide adequate environmental protection and provides certainty for operators when selecting a pit liner material.

Chapter 78 currently includes the requirement for the bottom of a temporary pit to remain at least 20 inches above the seasonal high groundwater table. This requirement has been in place since Chapter 78 was initially promulgated in 1989. In the final rule, under § 78.62, operators are required to determine that the pit meets this requirement prior to using the pit. The determination must be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The Department believes that this requirement is necessary and appropriate to ensure compliance with the long-standing requirement to maintain 20 inches of separation between the bottom of the pit and the seasonal high groundwater table.

The Department received considerable public comment on this proposed requirement from conventional operators indicating that it should be removed because it is expensive and unnecessary; however, this requirement is retained in the final rule. The Department believes that this requirement is necessary and appropriate to ensure compliance with the long-standing requirement to maintain 20" of separation between the bottom of the pit and the seasonal high groundwater table. The Department notes that the rule does not exclusively require this determination to be made by a soil scientist, but instead it allows the determination to be made by "a soil scientist or other similarly trained person." The Department believes that training can be provided to conventional oil and gas operators to ensure they have the skills necessary to accurately identify the seasonal high groundwater table and comply with this requirement without having to hire a professional soil scientist in all cases. In addition, the Department notes that since 1989, in order to ensure that they were in compliance with this requirement, conventional operators should have been conducting an evaluation of the soils beneath the bottom of their pit locations. Therefore, the Department believes that the effect of this new requirement will be to ensure that conventional operators document their determinations that their pits meet this long standing regulatory requirement prior to using them. Making this requirement even more important is the fact that once the liner is placed into the pit and the pit is put into service, it is very difficult for the Department to make a determination in the field regarding compliance with this requirement. The Department believes that this is an important provision and should not present any significant new burden on conventional operators.

The Department also received comments regarding the need to test the seams of pit used under § 78.56. The Department believes that visual inspections are not an acceptable means to ensure the liner integrity requirement is met. Seam testing should be conducted in accordance with a quality assurance and quality control plan and operators should consult with the manufacturer of the liner to determine appropriate testing protocols. The Department believes that testing of liner seams is an appropriate practice to ensure the quality of the liner installation and the rulemaking is appropriate to protect waters of the Commonwealth from pollution due to pits leaking regulated substances.

Many oil and gas 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 §§ 78.56 and 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. Sections 78.56 and 78a.56 seek 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, §§ 78.56 and 78a.56 will result in more efficient implementation of current requirements by including a requirement for the Department to publish approved structures on its website. 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. Subsections 78.56(a)(3) and 78a.56(a)(3) require 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 website 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 has 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 conventional operators indicating that the costs associated with equipping pits, tanks and approved storage structures with the prescribed security measures would be exorbitant for the conventional industry, which currently employs approximately 175,000 tanks (according to industry comments). The Department agreed that changes to§ 78.56 to remove the requirement to install equipment to prevent unauthorized access by third parties are appropriate for conventional operations but has retained this requirement for unconventional operators in § 78a.56. The Department also 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 noted above Department has revised § 78a.56 to disallow the use of pits on unconventional well sites and accordingly has removed the requirement to install fencing around pits on unconventional well sites. The Department has 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.

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

Sections 78.57 and 78a.57 in the final-form rulemaking contain requirements that apply to permanent storage of production fluids. The purpose of these provisions 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. These provisions are needed to minimize spills and releases to the environment.

In the proposed rulemaking, § 78.57(e) banned further use of underground storage tanks and required both conventional and unconventional operators to remove all underground storage tanks within three years of the effective date of the final rule. The Department received significant public comment on this provision from both conventional and unconventional operators arguing that it was inappropriate, overly burdensome and exorbitantly expensive. Conventional operators argued that with an estimated 150,000 buried tanks the cost to remove each tank and the cost to replace tanks that will be damaged in the removal process was significantly greater than the Department had considered when drafting the rule. In addition, operators indicated that the act of burying tanks is done to provide freezing protection for produced waters in the winter and to allow water and oil to be more easily separated. As a result of public comment, the Department has amended the final-form rulemaking in §§ 78.57(e) and 78a.57(e) to allow the use of buried tanks by both conventional and 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 has included provisions in the final rule to require the location of all existing and any new underground storage tanks at well sites to be reported to the Department.

Corrosion control

Sections 78.57(f) and 78a.57(f) implement 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 commenters argued that these provisions should not apply because storage tanks on well sites are not permanent. In the context of tanks regulated under §§ 78.56 and 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 timeframes. However, in the context of tanks regulated under §§ 78.57 and 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 §§ 78.57 and 78a.57 are permanent and subject to the corrosion control requirements in Section 3218.4(b) of the 2012 Oil and Gas Act.

Commenters also argued that because the Storage Tank and Spill Prevention Act (Tank Act) 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 must comply with corrosion control requirements in §§ 245.432 and 245.531 – 245.534 (relating to corrosion and deterioration prevention) 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) was enacted after the Tank Act.

The Department notes that the final rule 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 has also explicitly removed 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 non-metallic tanks which can often be less expensive than a steel equivalent and do not require any additional cost to ensure protection from corrosion.

Periodic inspections

Sections 78.57(i) and 78a.57(i) require operators to conduct periodic inspections of tanks used to control and store production fluids on a well site and document each inspection. The Department initially proposed that all inspections should be conducted monthly, which is the same frequency as required by the Department's storage tank regulations, but has revised the requirement to be monthly for unconventional operators and quarterly for conventional operators. The periodic 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. Requirements to conduct periodic inspection of production tanks are appropriate to ensure that the tanks are designed, constructed and maintained to be structurally sound with sound engineering practices adhering to nationally recognized industry standards and the manufacturer's specifications. The Department received significant public comment from conventional operators that this requirement is unnecessary and overly burdensome for conventional operations for a variety of reasons.

First, commenters suggested that periodic inspections are not needed because, according to the Department's compliance data, there were only 8 instances of leaking tanks in use by conventional well operators between 2008 and 2014.The commenters asserted that with more than 175,000 tanks are in use at conventional sites this suggests that only 0.000045% of all tanks used by conventional operators have ever been documented to leak. It is not clear to the Department which inspections are included in that count, but the Department's review of inspection data for 2014 alone reveals more than a dozen incidents where quarterly inspections may have mitigated a tank storage release. In addition, the Department notes that since storage tanks are not subject to many inspections, the number of leaks found by the Department expressed as a fraction of the total number of inspections is not a reliable measure of the frequency of storage tank releases. Finally, the Department inspected only slightly more than 6% of the conventional wells in 2014, so it is presumable that there were storage tank releases that are unknown to the Department, which is a problem that could be mitigated by well operators conducting periodic inspections.

Second, commenters suggested that requiring conventional operators to comply with requirements similar to those placed on unconventional operators is inappropriate because the storage tanks used at conventional well sites are significantly different than those used at unconventional well sites. The Department does not believe that the production tanks used by conventional operators are significantly different than those used by unconventional operators. While the tanks used by unconventional operators may be larger in some cases, tanks used by the conventional well industry can be large enough to cause a significant spill, and the differences between the substances stored in the conventional well industry compared to unconventional is arguably not as great is represented by the conventional well operators.

Third, commenters suggested that the difference in water quality between conventional and unconventional wells is significantly different. Commenters presented chemical analysis of conventional and unconventional produced water to demonstrate the chemical differences. The USGS provides an alternative source of data on the following webpage:

http://energy.usgs.gov/EnvironmentalAspects/EnvironmentalAspectsofEnergyProductionandUse/ProducedWaters.aspx#3822349-data

Below is a link to download the Complete List of Provisional National Produced Waters Geochemical Database Materials:

http://energy.usgs.gov/Portals/0/Rooms/produced_waters/tabular/USGSPWDB_v2.1.xlsx

The following data show a comparison between the data provided by the Pennsylvania Independent Petroleum Producers (PIPP) and appropriate data extracted from the USGS spreadsheet:

	ratio of

					unconventional over conventional	
Substance	Shallow – PIPP	Conventional - USGS	Marcellus - PIPP	Unconventional - USGS	PIPP	USGS
Barium	48.4	397	6500	1149	134.3	2.9
Calcium	6179	14075	18000	7410	2.9	0.5
Iron	53	114	60	39	1.1	0.3
Lithium	2.2	6.1	150	60	68.2	9.8
Manganese	4.2	13.4	5	3.5	1.2	0.3
Potassium	90	894		435		1.8
Sodium	19879	27327	48000	35459	2.4	1.3
Strontium	110	994	4000	1489	36.4	1.5
Bromine	628	752		1081		1.4
Chlorides	42954	87562	116900	50085	2.7	0.6
TDS	80106	140236	195000	85293	2.4	0.6
average ratio:					28.0	1.8

In the preceding table, the two columns to the right compare the ratios of contaminants in produced fluid from deep wells over shallow wells. For example, PIPP asserts the barium in produced fluid from Marcellus wells is 134.3 times greater than from shallow wells. According to the USGS data, that ratio is actually 6 to 1. Overall, data presented by PIPP suggests the contaminants in produced fluid from Marcellus wells average 28 times greater in concentration compared to shallow wells, whereas the USGS data show the average contaminant concentration from unconventional wells is only 1.8 times greater than from conventional wells. For calcium, iron, manganese, chlorides, and TDS, the data provided by PIPP indicates greater concentrations from unconventional wells, whereas the data from USGS shows greater concentrations from conventional wells. Although the data source selected by PIPP claims the concentration of contaminants in produced fluid from unconventional wells is greater than from conventional wells for every substance listed, the USGS data show a near even split with five substances out of eleven in greater concentration from conventional wells compared to unconventional wells. Based on this information, the Department has determined that the differences in contaminant concentrations between conventional and unconventional produced fluids do not warrant lax regulatory standards for control, storage and disposal of production water from conventional wells.

The Department continues to believe that periodic inspections are appropriate common sense accident prevention safeguards that every storage tank operator should follow. In response to comments, the Department has amended § 78.57(h) to reduce the frequency of inspection from once per calendar month to once per calendar quarter to allow coordination between tank inspections and mechanical integrity assessments required under § 78.88 which requires wells to be inspected on a quarterly basis. This change will have the effect of reducing the burden on conventional operators while ensuring that storage tanks for produced fluids on well sites are inspected periodically.

Secondary containment

Section 78.57(c) and 78a.57(c) of the 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.

Some commenters stated that it is contradictory for the Department to allow the spreading of brine on roads in § 78.70 yet require secondary containment around aboveground tanks containing brine. The Department requires brine road-spreading plans be submitted on an annual basis that are reviewed and approved by the Department. Also, monthly reports must be submitted listing the locations, frequency and amount of brine spread during the previous month. Provisions in § 78.70 also include environmental controls consisting of maximum application rates, chemical analysis, distance restrictions from surface water, 24 hour notice and source information. 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, the final rule 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, commenters 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.

§§ 78.58. Onsite processing

Sections 78.58 and 78a.58 codify 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.

The final rule also seeks to streamline this process by including a requirement for the Department to publish approved processes on its website. 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 § 78.58 and § 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 the subsection 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 no longer apply and the Waste Management program regulations govern testing and handling of the waste.

Commenters 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 federal DOT 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 has added §§ 78.58(d) and 78a.58(d) to this rulemaking. These new subsections 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 (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 commenters indicated that the rule 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 the rule 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.

§§ 78.59a and 78a.59a. Impoundment embankments; and §§ 78.59b and 78a.59b. Well development impoundments

Sections 78.59a, 78.59b, 78a.59a and 78.59b of the final-form rulemaking 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)-(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 is 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 sixteen 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 §§ 78.59a, 78.59b, 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 manor would allow for the potential for a catastrophic failure of the impoundment that may cause serious harm to public health and to the environment.

Sections 78.59b(d) and (f) and 78a.59b(d) and (f) specify 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 25 Pa. Code Chapter 105. The Department disagreed 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 § 78.59a provides for the structural integrity of the impoundment to provide adequate public safety and that § 78.59b 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.

The final-form rulemaking also establishes registration of existing and future well development impoundments with the Department electronically through its website. 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 25 Pa. Code Chapter 102.

Also, the rulemaking establishes that well development impoundments need to be restored within nine months of completion of hydraulic fracturing of the last well serviced by the impoundment. Restoring these facilities is needed to ensure that an extension for restoration may be approved under §§ 78.65(c) or 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 the rule made on final included technical adjustments of the requirements. In subsection (a)(5), soil classification sampling rates are adjusted from one sample per 1,000 ft3 to one sample per 10,000 ft3 which is a more appropriate sampling rate. Also added to subsection (a)(5) is a requirement 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).

In subsection (a)(8)(IV), soil compaction standards are included in the final rulemaking, with reference to several ASTM test methods. The Department also added language in subsection (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 §§ 78.59b(h) and 78a.59b(h), the final-form rulemaking allows operators to request to store mine influenced water 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 commenters were concerned about the potential to allow operators to store MIW in well development impoundments. These commentators assert that the quality of MIW varies greatly throughout the Commonwealth and the term includes MIW that has been treated, which may be very high quality. The Department disagreed with these commentators because §§ 78.59b(h) and

78a.59b(h) specify that before MIW is allowed to be stored in a well development impoundment, the Department must 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 in order to provide additional sources of water for operators to use for well development purposes.

Security Issues (fences)

Sections 78.59b(e) and 78a.59b(e) of the final-form rulemaking require 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.

§§ 78.59c and 78a.59c. Centralized impoundments

The final rulemaking requires all centralized impoundments to comply with permitting requirements in Subpart D, Article IX, or close within three years of the effective date of the regulation. When initially proposed, the rule 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.

Commenters 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, 25 Pa.Code 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 the Commonwealth. Therefore, the Department has determined that all future centralized wastewater impoundments will be regulated by the Department's Waste Management Program. The rule will require oil and gas operators to comply with the residual waste management rules 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.

§§ 78.60 and 78a.60. Discharge requirements

The final rule continues to allow operators to discharge tophole water or water in a pit as a result of precipitation onto a vegetated area capable of absorbing the water and filtering solids. Commenters argued the Department should ban the discharge of tophole water for a number of reasons. The rulemaking allows the discharge of tophole 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 tophole water and filtering solids in the discharge. Tophole 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.

§§ 78.61 and 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 has amended the final rulemaking to ban the use of pits for temporary waste storage at unconventional well sites. The Department has 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.

Conversely, the typical type and scope of use by conventional operators is generally compatible with the technical standards for temporary pits prescribed under § 78.56. The Department has allowed the disposal of residual wastes including contaminated drill cuttings in a pit at conventional well sites for decades. When done in accordance with appropriate environmental standards, such disposal can occur without significant harm to public health and safety or the environment. Additionally, the Department has not banned the disposal of residual waste containing contaminated drill cuttings in a pit at a conventional well site. As long as the requirements in § 78.62 are met, the disposal of residual wastes containing contaminated drill cuttings at conventional well sites will not result in significant harm to public health and safety or the environment. Allowing continued disposal of waste in a pit at a conventional well site and requiring an individual permit for disposal of waste at an unconventional well site is the least burdensome, acceptable alternative.

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 commenters 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 §§ 78.61 and 78a.61 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 §§ 78.61 and 78a.61 requiring operators to provide notice to surface landowners of the location of cuttings disposal or land application.

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

Several comments were received stating opposition to the proposed language requiring a certified soil scientist to determine elevation of seasonal high water table. Initially, the language of this section in the proposed rulemaking required a certified soil scientist would be required to determine the elevation of the seasonal high water table. The Department revised the rulemaking to allow a certified soil scientist or "other similarly trained persons" to make the determination as well, which may represent a substantial cost savings to the operator.

As written, the rule does not exclusively require this determination to be made by a soil scientist, but instead it allows the determination to be made by a soil scientist or other similarly trained person. Since 1989, in order to ensure that they were in compliance with this requirement; conventional operators must have been conducting an evaluation of the soils beneath the bottom of their pit locations. Therefore, the Department believes that the effect of this new requirement will be to ensure that conventional operators document their determinations that their pits meet this long standing regulatory requirement prior to using them. Making this requirement even more important is the fact that once the liner is placed into the pit and the pit is put into service, it is often nearly impossible for the Department to make a determination in the field regarding compliance with this requirement. The Department does not believe that this new requirement presents any significant new burden on conventional operators. This provision does not impact operators of unconventional well sites since the rule does not allow use of pits at such well sites.

A requirement to give the surface landowner notice of the location of disposal was added to subsection (a)(5). Some commenters believed that rather than require notice, the Department should require landowner consent before allowing for disposal of residual waste in pits. 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 §§ 78.62 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 §§ 78.62 requiring operators to provide notice to surface landowners of the location of cuttings disposal of residual waste in a pit on the well site.

Finally, as part of the Department's effort to protect the waters of the Commonwealth, a restriction on disposal within the floodplain was added to subsection (a)(7).

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) 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.

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

The Department added language throughout the section clarifying that only the solid fraction of residual waste may be disposed on the well site through land application. Subsection (a)(14) already requires the free liquid fraction of the waste to be removed, but the changes emphasize this point.

A requirement to give the surface landowner notice of the location of disposal was added to subsection (a)(5). Some commenters believed that rather than require notice, the Department should require landowner consent before allowing for disposal of residual waste through land application. 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 §§ 78.63 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 §§ 78.63 requiring operators to provide notice to surface landowners of the location of cuttings disposal of residual waste in a pit on the well site.

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.

§§ 78.63a and 78a.63a. Alternative waste management

This is a catch-all section added at final rulemaking indicating that an operator may seek Department approval to manage waste in a manner other than that outlined in §§ 78.56 – 78.63 or 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 the final-form rulemaking, but the Department believes that this catch-all provision will serve as a backstop to those provisions.

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

The existing § 78.64 requires secondary containment that meets federal requirements under 40 CFR Part 112 (relating to oil pollution prevention) to be implemented around oil tanks in order to prevent the discharge of oil into waters of the Commonwealth. The Department has expanded this requirement to include tanks that contain condensate (light liquid hydrocarbons) because the United States Environmental Protection Agency considers condensate that is liquid at atmospheric pressures and temperatures to be "oil." This rulemaking change will apply to both conventional wells and unconventional wells that produce condensate in § 78.64 and 78a.64, respectively.

The Department received comments both for and against the Department's removal of language requiring secondary containment for singular tanks with a capacity of at least 660 gallons in §§ 78.64 and 78a.64. The Department has revised the rulemaking language in §§ 78.64 and 78a.64 from 660 gallons to 1,320 gallons in order to be consistent with federal Spill Prevention, Control and Countermeasure Plan regulations at 40 CFR Part 112. Making this change matches Pennsylvania's requirements to the national standards for regulation of oil and condensate storage.

The Department received comments stating that the term containment is used in various contexts throughout the rule making document and is confusing. As a result, the Department added definitions for "primary containment" and "secondary containment" in §§ 78.1 and 78a.1. These terms are used in the throughout the rulemaking when referring to specific types of containment.

The rulemaking in §§ 78.64 and 78a.64 requires that all tanks that store hydrocarbons have secondary containment within two years of the regulations going into effect, or at the time the tank is replaced, refurbished or repaired, whichever is sooner.

§ 78a.64a. Secondary containment

Section 3218.1of the 2012 Oil and Gas Act establishes the requirement for secondary containment systems and practices for unconventional well sites. As a result, the Department created § 78a.64a in this rulemaking to implement these statutory requirements for unconventional well sites.

Secondary containment at unconventional well sites must 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. The 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 lists six specific substances that must be stored in secondary containment and that this new subsection broadens the scope of that statutory list to include all regulated substances, including solid wastes and other regulated substances in equipment or vehicles. The commenters 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 § 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 such pollution, the Department may, by rule or regulation, establish the conditions under which such 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 "Unconventional well sites shall be designed and constructed to prevent spills to the ground surface or spills off the well site." found in § 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.

The rulemaking establishes chemical compatibility and maximum permeability standards 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 the rulemaking language 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) 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, whether or not the stormwater has been discharged or discarded and must be handled and disposed of accordingly.

Secondary containment shall be inspected weekly to ensure integrity. Repairs to damaged or compromised secondary containment must be done as soon as practicable. Secondary containment inspection and maintenance records must 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 must be stored on site, but that operators must 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 found in the original proposed rulemaking has been removed 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.

§§ 78.65 and 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 the state, 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. But 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. Post Construction Stormwater Management (PCSM) requirements are already codified in § 102.8 and are needed to prevent pollution from improperly managed stormwater, and requires 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 §§ 78.65 and 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 as detailed below.

Sections 78.65 and 78a.65 were essentially re-written after the first comment-response 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 cross through, underlines, all caps, etc. 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 sections do not deviate greatly from the proposed regulatory language.

Several commentators were of the opinion that the proposed restoration requirements included in the final rulemaking were not stringent enough and should require more than restoration to approximate original conditions. These commenters want to see the restoration requirements require operators to reestablish prior existing biological communities and ecosystems as well as reestablish the entire site to its exact pre-existing conditions. This position proposes making §§ 78.65 and 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 must 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”, Document 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 recognition of the fact that restoration to original contours may not always be feasible. Subsections 78.65(a)(1) and 78a.65(a)(1) allow 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 timeframe is consistent with requirements in the 2012 Oil and Gas Act. Operators may request an extension of the restoration timeframe 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, the regulation requires restoration of the well site within nine months after completion of drilling of all permitted wells on the site or within nine months of the expiration of all existing well permits on the site, whichever is later. For post-plugging, it requires restoration within nine 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 must 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 rulemaking. 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 nine months to be consistent with other restoration requirements.

Some operator's comments expressed concern that restoration within nine months may not work in every situation. Under the regulation, operators may request an extension of the restoration timeframe 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 revisions to §§ 78.65 and 78a.65 in the draft-final rule addressed comments on this section that expressed continuing confusion regarding what constitutes restoration as the term is used both in Chapter 78 as well as in Chapter 102, and what the associated requirements are. The changes to this section in the final rule 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, inter alia, 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.

Written Restoration Plan

Comments were received from conventional operators questioning the need for a written restoration plan at all well sites. They were concerned that the need to comply with § 102.8(g) requirements within the plan would impose excessive design and construction costs upon the conventional industry with little environmental benefit. In response, the Department agrees that operators do not need to develop written restoration plans for all well sites and has modified the regulation in subsection (b)(7) to require development of written restoration plans only for well sites which require permit coverage under § 102.5(c) (relating to permit requirements).

Landowner consent for storing equipment not needed for production (agreements vs 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 such 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.

§§ 78.66 and 78a.66. Reporting and remediating 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 commenters felt that it was inappropriate to require cleanups of spills and releases under Act 2 because the 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 relating to a release of a regulated substance addressed under various environmental statutes, including the Clean Streams Law, the Solid Waste Management Act, and the Hazardous Sites Cleanup Act. Many substances that are spilled at sites regulated under the Oil and Gas Act are regulated as waste under the Solid Waste Management Act or as pollutants under the Clean Streams Law (see, for example, sections 3273 and 3273.1 of the 2012 Oil and Gas Act, 35 Pa.C.S. §§ 3273, 3273.1). 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 commenters felt that § 78.66(b)(2) reporting requirements went beyond the scope of what is required in § 91.33. The Department believes that the final rulemaking for subsection (b)(2) will serve as guidance for the responsible party to provide enough information, to the extent known, necessary for the Department to properly asses the reported spill incident, so the appropriate initial response can be employed by the Department.

Many commenters were concerned that the public and other government agencies were not made aware of all spills and releases that occur at both conventional and unconventional well sites. The regulations require that operators report releases within two 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 via email.

The regulation 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 must be restored or replaced in accordance with §§ 78.51 or 78a.51.

The spill or release area must then be remediated appropriately through Act 2 (of 1995) 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. The 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 commenters 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 has removed the alterative process from the 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 the regulation 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 timeframes established in the final rulemaking are modeled on the timeframes established for corrective actions for releases from storage tanks in 25 Pa.Code 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 25 Pa. Code Chapter 250. These timeframes are appropriate and have built-in flexibility to address the unique considerations posed by each remedial site. Finally, the Department notes that the timeframes establish requirements for the steps that will lead to completion of the corrective action but do not establish a timeframe 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.

§§ 78.67 and 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 §§78.67 and 78a.67 to require borrow pits to be restored nine months after completion of drilling the final well on a well site serviced by the borrow pit instead of nine 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 §§ 78.65 and 78a.65, and 78.59a and 78a.59a. 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 nine months is a reasonable time frame to ensure the operator has an opportunity to achieve this requirement.

§ 78a.68. Oil and gas gathering lines

The rulemaking requires the use of highly visible flagging, markers or signs to be used to identify the shared boundaries of the limit of disturbance (LOD), 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 i.e. 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 LOD is too great to not include this provision in the 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.

The 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 removed from the 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.

The 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.

The 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 found in Chapter 105. The Department received comments 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) has been modified 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.

The final-form rulemaking requires all buried metallic gathering pipelines to be installed and placed in accordance with federal statute 49 CFR Part 192, Subpart I or 195, Subpart H (relating to requirements for corrosion control). 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 "all buried metallic pipelines shall be installed and placed in operation in accordance with 49 CFR Pt. 192, Subpart 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

The rulemaking reinforces that horizontal directional drilling for oil and gas pipelines (HDD) is subject to the regulatory requirements found in 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 found 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.

The 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 must be monitored for any signs of drilling fluid discharges as required in the 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.

The final-form rulemaking includes a requirement to immediately notify the Department of a 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 the 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 horizontal directional drilling 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 must be installed aboveground, as required in the 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.

The 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 (relating to permit application for construction or modification of culverts and bridges). 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.

The 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 must 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 the rulemaking.

The 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 rulemaking.

The 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 a 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 two years after their removal. The Department believes one 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.

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

§ 78a.69. Water management plans

The Department received comments urging the Department to include conventional operations in the requirement to develop water management plans (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 regulation 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 the 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.

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

Commenters 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. Conventional brine may be spread on roads for dust control and road stabilization under controlled conditions that require the brine to meet certain chemical parameters for use and sets limits on the application location, rate, and duration.

Section 78a.70 of the final-form rulemaking was amended from proposed to clearly ban the use of brines and produced fluids from unconventional wells for dust control and road stabilization.

§§ 78.70a and 78a.70a. Pre-wetting, anti-icing and de-icing

Commenters recommended the complete prohibition of brine being used to de-ice roads. The Department disagrees with the comment. Application rates, location of application sites relative to water bodies, site characteristics are designed/selected to prevent runoff from reaching waters of the Commonwealth. Production brines from conventional wells have a history of use as pre-wetting, anti-icing and de-icing agents. Production water from unconventional wells does not have this same history and the Department believes it is prudent to err on the side of protection of public health and safety and the environment until it can be demonstrated otherwise. Due to the consideration of road de-icing with brines and the determination that if, when done by the conventional industry, under the manner detailed in the rulemaking, this is the least burdensome, acceptable alternative.

Section 78a.70a of the final-form rulemaking was amended from proposed to clearly ban the use of brines and produced fluids from unconventional wells for pre-wetting, anti-icing and de-icing.

§§ 78.121 and 78a.121. Production reporting.

The final rule 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 comment on this provision from unconventional operators. Operators noted that 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) is not reliant on Act 173, therefore the legislative intent of that act is not relevant to the subsection. The statutory authority for subsection (b) is found under provisions of the Solid Waste Management Act, particularly Section 608(2):

> The Department shall… (2) Require 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 must 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 six-month period. Operators must account for and report all wastes generated in the six-month period already, the only end difference in terms of overall reporting should be that the Department would possess data segregated by month after the effective date of the rulemaking. 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 (OGER) 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 bi-annual 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 timeframe.

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

Commenters 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 primary new requirement in section 78.121 is for the operator to report the specific facility or well site where the waste was managed. Providing such information to the Department is a standard practice in all waste management programs and does not single out the oil and gas industry.

The Department believes that responsible operators are aware of and track their waste generation, transportation, treatment, storage and disposal and operating without such awareness is not a best management practice and is unacceptable in the 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 six-month reporting system or imposing a load-by-load manifest system as is currently required for hazardous wastes.

Conventional operators are only required to report waste production from wells on an annual basis, not on a monthly basis as is required for unconventional well operators.

§§ 78.122 and 78a.122. Well record and completion report

The primary change to these sections between proposed and final relates to area of review requirements. The certification by the operator that the monitoring plan required under either §§ 78.52a or 78a.52a was conducted as outlined in the area of review report was moved from the well record to the well completion report. This change 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 defines "completion of a well" as: "The 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 (i.e., 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.

§§ 78.123 and 78a.123. Logs and additional data

These sections require 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 the provisions in subsections (a) and (d) on final. 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 timeframes for submission and the perceived timeframes 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 the 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 the language in Section 3222(d). The final-form rulemaking retains the three and five-year periods in Section 3222(d) of the 2012 Oil and Gas Act for information contained in Section 3222(b)(5) and (c) (drill cuttings). 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 the final-form rulemaking.

G. Benefits, Costs and Compliance

Benefits

Both 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 oil and 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 Statewide 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 final-form rulemaking requirements regarding wastewater processing at well sites will encourage the beneficial use of wastewater for drilling and hydraulic fracturing activities.

The amendments contain several new notification requirements which will enable Department staff to effectively and efficiently coordinate inspections at critical stages of pit construction, modular aboveground storage facility installation, drill cutting or residual waste disposal, onsite residual waste processing, horizontal directional drilling and road-spreading 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 oil and gas development in this Commonwealth.

Compliance costs

Unconventional Operators Costs
<u>Assumptions</u>

When initially proposing this rule, 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 1 out of every 2 permitted unconventional wells are drilled.

In addition, the Department estimated that there was an average of 3 unconventional wells per well site.

Since considerable time has passed since the rule was initially proposed, the Department was able reevaluate the rate at which unconventional wells are permitted and drilled in Pennsylvania and include data for 2013, 2014 and the first 3 quarters of 2015.

The Department's records also show that there are currently 3,387 unconventional well pads with at least one well drilled and a total of 9,486 total unconventional wells located within the 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 regulation must be factored on a well site basis, not on a per well basis. Many of the processes proposed for regulation in this rulemaking include activities integral to the operation of several wells and even several well pads.

Year	**Unconventional Wells Permitted**	**Unconventional Wells Drilled**
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 9/8/2015)**

Based on the data shown in the above table which represents the most recent 5 year period in history, 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 3 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 wells permitted x 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**

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 related to the cost of implementing the public resource screening process requirements in Section 78.15(f)-(g). Commenters disagreed with the Department's estimates of cost for permit conditions mitigation measure to protect public resources. Commenters 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 below an 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 the final rule. 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 Section 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 x 434 = $868,000
$40 x 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 § 78.15(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 must also notify potentially impacted pubic 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 x 434 x 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 discussed above 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 x 1,300 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;

a. Researching the depth of identified wells;

b. Development of monitoring methods for identified wells, including visual monitoring under accompanying section 78.73;
c. Gathering surface evidence concerning the condition of identified wells;
d. Gathering GPS, i.e., coordinate data for identified wells;
e. Introduction of a provision of advanced notice to adjacent operators under accompanying section 78.73; and
f. The assembly of the above data in an area of review report and monitoring plan and the submission of the report at least 30 days prior to the commencement 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 Pennsylvania, 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 two (2) days of field work and one (1) day of office work to compile the data necessary for submission. It should be noted that current laws in Pennsylvania 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 regulation. The individual had asked that limits be placed on offset wells requiring identification in the area of review (active only) and had 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 well 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 $6.00 per mailing.

Although the Department contends that the work specified in this section of the regulation is already being conducted by responsible unconventional operators in the state 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 hydraulic fracturing communication incidents documented in Pennsylvania. 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 (e.g., 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 and/or purchasing gas on the open market. These costs are potentially further compounded by any environmental issues that must be addressed (e.g., 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 must be completed, plugging costs of any unconventional wells affected beyond repair and any improperly plugged legacy wells, material costs (e.g., 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 $13,000,000 to $16,000,000. Total costs for the third scenario were in excess of $1,000,000. The Department acknowledges that in certain cases, even with the implementation of the regulation 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 API, 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)

The final rule requires all oil and gas operators to develop and implement a site specific PPC Plan under §§ 78.55 and 78a.55. The Department received significant public comment from oil and gas operators on this section. Commenters expressed concerns about §§ 78.55(a) and 78a.55(a) which simply reiterate the requirements already existing in §§ 91.34 and 102.5(l). Because §§ 78.55(a) and 78a.55(a) do 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 but upon further evaluation, the Department has 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 promulgated. 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 in order 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 rulemaking nor is it required by this 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 rulemaking to ensure that all PPC plans are revised annually. There are no specific review and update timeframes included in the rulemaking. The rule 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 promulgated in 1989. Therefore, there is no new cost attributed to this provision.

Finally, the rule does not include a requirement that every single site where activities including the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants must have the PPC Plan posted on site at all times. The rule does not include this requirement or anything resembling this requirement. In fact, the rule 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 where there is an increased risk of a spill, release or other incident, but it is not required by § 78.55. 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 and PA Fish and Boat Commission and the Landowner (§78a.55(f))

The final rulemaking includes a requirement for operators to provide copies of the site specific PPC Plan to the Pennsylvania 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 x $25 x 2 = $21,700.

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

Banning Use of Pits (§ 78.56)

The final rule 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.

The final rule also requires pits at unconventional well sites to be restored within 6 months of the date of the final rule. The Department does not anticipate that this provision 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 the rule required unconventional operators to install fencing around pits on well sites. The final rule does not allow unconventional operators to utilized 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 & labor to inspect and test the integrity of the liner (§78a.56(a) and 78a.62)

When initially proposed the rule required unconventional operators to make a determination of the depth to seasonal high groundwater table and inspect liners for pits on well sites. The final rule does not allow unconventional operators to utilized 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 this section. 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 x 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 x 434 = $108,500
$2,000 x 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 DEP 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 x (434 x 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 regulatory proposal 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 x 434 = $2,170,000

$10,000 x 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, the rule prohibited the use of underground or partially buried storage tanks for storing brine. Under the final-form rulemaking, 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 provision because the cost was dependent on the number of buried tanks across the Commonwealth and the Department was unable to estimate the number of buried tanks at that time. As a result of public comment, the Department has amended the final rule 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 the final rule 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)-(g))

Subsections 78.57(f)-(g) implement 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 table below, 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 Protection	Ratio of Cost of Corrosion Protection to Replacement
25 bbl.	$1,800.00	$350.00	$450.00	0.44
50 bbl.	$2,200.00	$350.00	$650.00	0.45
100 bbl.	$3,451.00	$350.00	$1,200.00	0.45
140 bbl.	$5,144.00	$350.00	$1,300.00	0.32

210	$6,083.00	$350.00	$1,600.00	0.47

Finally, this requirement is a statutory requirement under Section 3218.4(b) of the 2012 Oil and Gas Act. As noted above, §§ 78.57(f)-(g) simply implement this requirement. The Department has also explicitly removed 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 non-metallic 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/hr. the cost to perform monthly maintenance inspections is $2,700,000 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 $2,700,000.

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

The Department has added § 78.58(d) to this rulemaking which 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. 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 must 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 sites x 75% = 326 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 sites x 50% = 163 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, in order 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 x $2,000 = $326,000
163 x $5,000 = $815,000

Cost of Training =
163 x $1,000 = $163,000
163 x $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 x $1,000 = $85,000

85 x \$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, 78a.59b)

In the final rule, §§ 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 \$25,000,000 based on the Department's estimate of 100 existing freshwater impoundments. The commenter does not provide a breakdown of how the projected cost was derived.

The Department disagrees with the commenter's cost estimate. First, many of the new requirements are only applicable to new impoundments. Operators must only certify that existing impoundments meet the requirement for having a synthetic liner, being surrounded by a fence and properly storing mine influenced water. The rule 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 mine influenced water is properly stored exists regardless of the well development requirements in Chapter 78 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 commenters included these types of facilities in their cost estimate, 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 the rule. 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 ft^2 of synthetic liner to comply with the rule. The estimated cost of installed 30 mil HDPE liner to meet this requirement is \$0.40/ft^2 resulting in a total cost of \$1,260,000.

250,000 x 0.40 x 90% x 140 = $1,260,000 for liner installation

The cost of the fencing is dependent upon the size of the impoundment and the type of fencing used determines. Based on 140 well development impoundments throughout the Commonwealth and assuming that none of them currently have fencing the Department estimates that the total cost of this provision is between $980,000 and $7,000,000.

$7,000 x 140 = $980,000

$50,000 x 140 = $7,000,000

The rule 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 $2,253,000 and $8,273,000.

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 §§ 78.59a and 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 $0.40/ft^2 for installed 30 mil HDPE liner and 250,000 ft^2 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 $2,210,000 and $3,070,000.

($3,500 + $100,000 + $7,000) x 20 = *$2,210,000*

($3,500 + $100,000 + $50,000) x 20 = *$3,070,000*

Therefore, the total estimated annual cost of this provision is between $2,210,000 and $3,070,000.

Centralized Impoundment (§ 78a.59c)

The final rule 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 when the rule was initially proposed 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 impacted and how operators decide to comply. The Department received significant comment on this section from unconventional operators. Commenters 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. Commenters also noted that if an operator chooses to close an existing permitted centralized impoundment due to this rule, an owner may realize a loss of $1,500,000 to $2,500,000 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 the 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 $1,500,000 and $2,500,000. To the extent that operators choose to restore and replace all of the existing centralized impoundments, the estimated cost of this provision is between $33,000,000 and $55,000,000.

20 x $1,500,000 = *$30,000,000*

20 x $2,500,000 = *$50,000,000*

The initial cost of this provision is estimated to be between $39,000,000 and $65,000,000.

Based on past trends, the Department estimates that 4 centralized impoundments will be constructed per year. If the cost to permit and construct impoundments under the 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.62-63)

The final rule 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 Green 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 of 2014, July-December 2014 and January-June 2015 cuttings from only 5 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 5 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)

The 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 rule 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 x 434 = $60,760,000

The total annual cost of this provision is $60,760,000.

Section 78a.64a requires materials used for secondary containment to have a coefficient of permeability not greater than $1x10^{-10}$ 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 Pennsylvania 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 must also be installed in a much thicker layer than synthetic liners to provide sufficient protection which means more material must 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 $5000 to run on each chemical type found at a site. Operators suggest ASTM D543 as an alternate test. By considering the comments, rulemaking language 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 existing 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", Document 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 both in Chapter 78a as well as in Chapter 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, inter alia, 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. Commenters argued that the Department failed to include any estimate for the cost associated with the new site restoration requirements. Commenters did not agree with the Department's position regarding cost savings due to the added provision of two-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 $21,700,000 savings, the restoration requirements are a cost of $130,000,000.

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 explained above. In addition, the Department disagrees with commenters' 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 two 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 has revised its estimate that this provision will result in $21,700,000 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 both the 2012 Oil and Gas Act and Chapter 102. To the extent that an operator would incur the costs listed above, 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 rule, 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. The final rule 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 3-4 times the alternative process. Commenters 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. Commenters did not provide any specific details to fully explain the estimated costs. Commenters 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 include 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 rule is that operators must 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 commenters 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 represent 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 must 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)

Subsection 78a.67(b) require the registration of the location of existing borrow pits within 60 calendar days after the effective date of the final-form rulemaking and registration of new borrow pits before there are built. This will be done electronically through the Department's website. 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.

Subsection 78a.67(a) requires an oil and gas operator who owns or controls a borrow pit that does not require a permit under the Noncoal Surface Mining Conservation and Reclamation Act (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 original 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))

These sections establish 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, Chapter 102 and Chapter 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))

The rulemaking requires that all buried metallic gathering pipelines shall be installed and placed in operation in accordance with federal statute 49 CFR Part 192, Subpart I or 195, Subpart H relating to requirements for corrosion control. 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 places in operation in accordance with 49 CFR Pt. 192, Subpart I (relating to requirements for corrosion control)." Section 78.68(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 this provision is a statutory requirement, the Department has not assigned a new cost.

The total new cost of this provision is $0.

Horizontal Directional Drilling(§ 78a.68a)

This section establishes common sense environmental controls for conducting horizontal directional drilling. These requirements are intended to help ensure that operators maintain compliance with the Clean Streams Law, Chapter 102 and Chapter 105 when conducting horizontal directional drilling. 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, Chapter 102 and Chapter 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)-(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 must be installed aboveground except when crossing pathways, roadways, railways, water courses or water bodies. The rule 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. Commenters 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.

Water management plans (§ 78a.69)

The final rule implements requirements in § 3211(m) which requires anyone who withdraws or uses water from water sources within Pennsylvania 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 water management plan.

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)

The final rule includes a requirement for unconventional operators to report waste production to the Department on a monthly basis. This new rule 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. Commenters 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 hours x $30/hour x 2 reports/year = $1,200
30 hours x $30/hour x 2 reports/year = $1,800

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

20 hours x $30/hour x 12 reports/year = $7,200
30 hours x $30/hour x 12 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 operators x $6,000 = $438,000
73 operators x $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 annual cost of this regulation on unconventional operators is between $41,358,000 and $73,463,000

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

Conventional Operators Costs

Prior to initially proposing revisions to this rule, the Department reached out to oil and gas operators, subcontractors, and industry groups to derive the cost estimates of the final-form rulemaking. The Department received significant comment regarding the cost estimates provided by the Department when the rule was proposed. Commenters also included comprehensive analysis of their estimated costs of the proposed rule. As a result of those comments and other information, the Department made significant revisions to the final rule.

Assumptions
When initially proposing this rule, the Department estimated based on data available at the time that there will be approximately 2,000 conventional wells permitted each year for the next 3 years.

On average, about 2 out of every 3 permitted conventional wells are drilled.

There is typically only 1 conventional well per well site.

2,000 permitted wells x .667 drilled rate = 1,334 wells drilled per year

The Department received comments that this estimated number was too low. Specifically, commenters argued that the Department should base cost estimates on a projected well drilling rate of 2,750 wells per year. Since considerable time has passed since the rule was initially proposed, the Department was able reevaluate the rate at which conventional wells are permitted and drilled in Pennsylvania and include data for 2013, 2014 and the first 3 quarters of 2015.

Year	**Conventional Wells Permitted**	**Conventional Wells Drilled**
2010	**3232**	**1733**
2011	**2185**	**1271**
2012	**1564**	**1019**
2013	**1645**	**956**
2014	**1268**	**789**
2015*	**400***	**307***

***Data extrapolated from first 3 quarters (300 wells permitted, 230 wells drilled as of 9/8/2015)**

Based on the data shown in the above table which represents the most recent 5-year period in history, it is clear that the Department's estimate was, in fact, quite conservative. Conventional well drilling has been on a steady decline in recent years and the Department does not have any reason to estimate that well drilling trends will suddenly and drastically reverse course in the next 3 years. The Department does not believe that the recommended rate of 2,750 wells per year is a reasonable estimate considering the most recent data available. The Department believes that its original estimate of 2,000 wells permitted per year and 1,334 wells drilled per year is a reasonable conservative estimate of the potential conventional well drilling activity over the next 3 years.

Cost Estimates

Electronic Filing

In the final-form rulemaking, nearly all applications and notifications required by the rule are to be made to the Department electronically. Electronic reporting of production data for all operators was established by the 2011 Subsurface Activities final-form rulemaking and is not a new requirement established by this rulemaking. The primary new requirement in §§ 78.121 and 78a.121 is for the operator to report the specific facility or well site where waste was managed. Providing such information to the Department is a standard practice in all waste management programs and does not single out the oil and gas industry. The Department received significant public comment from conventional oil and gas operators indicating that these requirements were excessive and overly burdensome for their operations because they do not own or operate computers. Commenters estimated that this provision would cost operators $1,225 in the first year and approximately $600 per year in internet service fees after that.

If some well operators do not have a computer, it is not necessary to purchase the latest technology equipment to comply with Chapter 78 reporting requirements. There is an abundance of used computer equipment available for very modest prices. The Department of General Services routinely sends used computers to auction for nominal prices, and it surely is not the only source of used computer equipment. What many computer users would consider obsolete computer equipment would be adequate to comply with Chapter 78 reporting requirements, and there are a variety of ways such equipment can be obtained at little to no cost. In addition the reporting requirements will not force well operators to buy expensive broadband internet access, as there are free or inexpensive dialup internet options also available in many areas. If well operators must buy and learn to use a computer to comply with reporting requirements, the equipment and skills will easily be usable for other tasks and may increase the well operators' earning potential. Well operators may want to buy more expensive computers or services than are necessary to comply with Chapter 78 reporting requirements, but any such extra costs would be voluntary.

Conventional operators are only required to report waste production from wells on an annual basis, not on a monthly basis as is required for unconventional well operators. 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 six-month reporting system or imposing a load-by-load manifest system as is currently required for hazardous wastes.

The Department will not assume non-compliance with existing requirements. Because operators have been required to provide production data to the Department electronically for several years, conventional operators should already have the necessary equipment and access necessary to provide electronic data to the Department. Therefore, the Department is not assigning additional costs based on the requirements of this final-form rulemaking.

New notifications to the Department

The final rule includes a number of new notification requirements. Operators must provide at least 3 days' notice to the Department prior to conducting the following activities.

- installation of pit liner (78.56)
- prior to commencing construction of a pit of greater than 250 ft^2 for servicing, plugging or recompleting a conventional well (78.56(e))
- prior to disposal of cuttings (78.61-78.63)
- prior to conducting onsite processing (78.58)
- prior to utilizing modular aboveground storage structure (78.56)
- after noticing deficiencies in tanks during monthly or quarterly inspections (78.57(h))

The Department received comments from conventional operators that these notification requirements will add costs of up to $10,000 per well due to the resulting delays. The Department disagrees with this estimate. The notification requirements are structured in a manner to allow significant flexibility in the timing. In addition, the Department believes that if operators know the requirements and plan accordingly, the requirement to make these notifications should not ever result in any delay for operations.

The total new cost of this provision is $0.

Identification of Public Resources (§ 78.15)

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 conventional gas well operators. Commenters disagreed with the Department's estimates of cost for permit conditions to protect public resources. Commenters argued that coordination with public resource agencies to consider impacts to other critical communities will impose an economic hardship on conventional oil and gas operators. The Department disagrees because operators are currently required to identify the habitats of special concern species where the proposed well site or access road will be located and describe measures proposed to be taken to avoid or mitigate impacts to special concern species. The applicant must provide a PNDI receipt with the well permit application and, if a potential impact to a special concern species is identified, the applicant must notify the applicable public resource agency. The applicant should also be consulting with the agency to identify appropriate avoidance and/or mitigation measures. As this is an existing well permit application component necessary to comply with the Department's constitutional and statutory obligations, the requirement to consider impacts to other critical communities in final rulemaking does not impose any new financial burden.

The first step in the process is identification. The Department believes this t 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 the final rule. 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. The Department estimates the cost of the field survey to be $500 and the cost of the electronic survey to be $40. Even though use of the online tool is required to comply with requirements protecting threatened and endangered species, the Department has included the cost in this estimate nonetheless.

$500 x 1,334 = $667,000
$40 x 1,334 = $53,360

$667,000 + $53,360 = $720,360

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§ 78.15(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 must also notify potentially impacted pubic 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 x 1,334 x 30% = $8,004

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 discussed above 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.

$720,360 + $8,004 = $728,364

The total cost of this provision is $ $728,364 *(not including consultation and mitigation).*

Protection of water supplies (§ 78.51)

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.

Conventional operators argued that the provision in Act 13 should be interpreted to mean that impacted water supplies must be restored to Pennsylvania Safe Drinking Water Act standards or previous water quality, whichever is poorer.

Conventional operators provided estimates that this provision will result in new costs ranging from $825,000 and $61,000,000 per year. The Department notes that given the need to provide replacement water based on the positive impact determination under either interpretation, the additional cost borne by operators is limited to the incremental cost of providing Pennsylvania Safe Drinking Water Act standards water as compared to the previous poor quality, not the difference between providing no water at all and meeting Pennsylvania Safe Drinking Water Act standards. Commenters did not provide a detailed explanation of how these estimates were derived so it is not clear to the Department if this fact was considered when developing this cost estimate.

This section seeks only to provide clarity to existing statutory requirements. Accordingly, the estimated new cost incurred by unconventional operators is $0.

The Department acknowledges that if Section 3218(a) of 2012 Oil and Gas Act is interpreted in the way conventional operators believe to be appropriate, costs incurred by operators are likely to be lower than what the statute currently requires.

The total new cost of this provision is $0.

Area of Review and Monitoring Plans (§§ 78.52a and 78.73)

This provision will affect each well drilled and stimulated using hydraulic fracturing.

The Department estimates area of review will cost $450 per each well.

$450 x 1,334 wells = $600,300

The total cost of this provision is $600,300.

Conventional operators submitted comments stating that they do not agree with the Department's 2013 assessment related to the area of review implementation costs. The industry feels that this section imposes a significant cost since operators are required to compile reports and possibly gain access to surrounding properties to conduct surveys. It has been stated that the surveyor's time to draw a well site map will increase from one day to as much as a week to collect the information and develop a plan covering 72 acres, raising current site map costs from $500 to $2500. If the surveyor has to provide the plat with GPS information, an additional cost of $1000 may be added to the total cost. The following summary table, which has been slightly modified from its original format, includes costs provided by the Pennsylvania Independent Petroleum Producers during the public comment period.

Subsection	Task	Description	Maximum Industry Cost Per Well
(b)(l)	Database Review	Operator must review Department databases. Make appointment. Travel 1-3 hours each way to Regional Office. Review database for 1-3 hours.	$500
(b)(2)	Historical Review	Operator must hire expert to research historical sources of information, such as farm line maps	$1,500
(b)(3)	Landowner Questionnaire	Operator must submit DEP questionnaire (does not yet exist) to landowners regarding location of abandoned and orphaned wells	Unknown
(c)(1)	Plat	Operator must submit a plat showing the location and GPS coordinates of all wells identified in (b).	$700
(c)(2)	Proof of Notification	Operator must submit proof that questionnaires submitted under (b)(3)	$30
(c)(3)	Monitoring Plan	Operator must submit plan for monitoring wells required under 78.73(c). Installation of monitoring tank may be required	$2,700

(c)(4)	Well Depth	Operator must submit true vertical depth of wells, if known	Unknown
(c)(5)	Source of Information	Operator must identify source of information for identified wells, if available.	Unknown
(c)(6)	Well Integrity	Operator must furnish surface evidence of failed well integrity, if available.	Unknown

Although conventional operators are required to comply with this section, it is anticipated that costs will be insignificant in comparison to potential liabilities associated with a hydraulic fracturing communication incident. Plats, which are currently required for all well sites, must be prepared by a competent engineer or surveyor in accordance with Section 3211(b) of the 2012 Oil and Gas Act. However, only the well sites requiring monitoring under Section 78.73 must field verified and surveyed. Although professional surveying firms are commonly employed by the unconventional industry, this is not required as indicated in Section 3211(b) of the 2012 Oil and Gas Act. Further, existing law under Section 3213(a.1) has required operators to identify all abandoned assets discovered on their leases to the Department for many years. The low-end cost for GPS units with sub-meter accuracy is $500, which could be amortized over many years of use. For an operator drilling ten (10) new wells per year, the cost would equate to $50 per well if a new GPS unit was purchased each year. If a professional surveying firm is hired, it is anticipated that the costs will be a fraction of those associated with unconventional sites due to the smaller surveyed area. An estimate of $250 is based on conversations with professional surveying companies and a proportionally reduced survey area of 1,000 feet by 1,000 feet.

Costs associated with the review of the Department's databases and historical maps have been estimated at $2,000 by the industry. Many of these sources are available free of charge and can be accessed online. Amortizing the purchase of a new computer ($500) and a web connection ($360) for ten wells drilled results in a per-well cost of approximately $90. However, since electronic reporting requirements having been in place for several years for production and waste, the Department estimates this cost should be $0 for most conventional operators in good compliance standing.

Because of the smaller footprint associated with the area of review for conventional operators, the Department believes that periodic offset well site inspections will be a cost-effective strategy in most cases, with some sites requiring rental of a poly tank for fluids management/containment. This along with reporting costs may push the per-well cost up another $225, which is inclusive of potential consulting fees and tank rental costs. Conservatively, the total cost estimate per well for operators not currently completing due diligence to perform this task is not expected to exceed $450 per well site on average.

For comparison, the Department recently summarized costs associated with two (2) hydraulic fracturing communication incidents. Responding to and addressing these incidents, which occurred at conventional well sites, resulted in costs of $280,000: $50,000 for remediation services and $230,000 for well plugging activities. Such costs are expected to increase substantially in situations where water supplies are impacted by migrating methane gas or when adjacent gas wells must undergo repairs. The company providing this information has indicated that these communication incidents could not have been avoided even with the new requirements in place. The Department acknowledges that in certain cases, even with the implementation of the regulation 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 API, a globally recognized industry trade organization.

Site Specific Prevention and Contingency Plan (PPC) Plans (§ 78.55)

The final rule requires all oil and gas operators to develop and implement a site specific PPC Plan under §§ 78.55 and 78a.55. The Department received significant public comment from conventional oil and gas operators indicating that this requirement was excessive and overly burdensome for their operations. The commenters argued that the requirement to develop and update site specific PPC plans is unnecessary because conventional well sites are all so similar that a single plan is sufficient to address all sites. The commenters also argued that maintaining a copy of the PPC plan on the site is overly burdensome and unnecessary for conventional operators. Commenters also expressed concerns about §§ 78.55(a) and 78a.55(a) which simply reiterate the requirements already existing in Chapters 91.34 and 102.5(l). Because §§ 78.55(a) and 78a.55(a) do 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.

Commenters estimated 200,000 discrete well and tank locations which would require a PPC plan under the final rule. Commenter's estimated costs of $40 for purchasing PPC plan storage units with $25 in labor to install each unit. Commenters also estimated $100 to prepare each plan if the preparation is done in house and $500 if the preparation is done by a contractor. Commenters also estimated that PPC plans would have to be updated annually, even though it is not required by the rule and that each PPC plan storage unit would require repairs each year. The total cost of the updates and the repairs was estimated to be $125/plan. Commenters did not provide a breakout of the estimated update and repair costs. Overall the total cost of this requirement is estimated by commenters from the conventional industry to be over $125,000,000. The Department does not agree that this is a reasonable cost estimate.

First, 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 promulgated. 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, in order for conventional 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 rulemaking nor is it required by this rulemaking that each PPC plan developed for a different well site must be unique. Therefore, the Department does not believe that the costs estimates by conventional operators of $500 to prepare each plan are reasonable. 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 also not the intent of this rulemaking to ensure that all PPC plans are revised annually. There are no specific review and update timeframes included in the rulemaking. The rule 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 promulgated in 1989. Therefore, there is no new cost attributed to this provision.

Finally, it appears that the commenters incorrectly assumed that every single site where activities including the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants must have the PPC Plan posted on site at all times. The rule does not include this requirement or anything resembling this requirement. In fact, the rule 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 where there is an increased risk of a spill, release or other incident, but it is not required by § 78.55. 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 landowner and PA Fish and Boat Commission (§ 78.55)

The final rulemaking includes a requirement for operators to provide copies of the site specific PPC plan to the Pennsylvania 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 Pennsylvania Fish and Boat Commission request the plan for every well site, the Department estimates the cost to be $66,700.

1,334 x $25 x 2 = $66,700.

The total new annual cost of this provision is estimated to be $66,700.

Tank Valves and Access Lids Equipped to prevent unauthorized access by third parties (§ 78.56(a)(6))

When originally proposed, § 78.56(a)(6) 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. The Department received significant public comment from conventional operators indicating that the costs associated with equipping pits, tanks and approved storage structures with the prescribed security measures would be exorbitant for the conventional industry which currently employs approximately 175,000 tanks. Commenters estimated the total cost of this provision to be $600,000,000 for installation of security measures on existing tanks and $6,300,000 annually for increased labor costs due to inefficiencies caused by the security measures on well sites. For new sites, commenters estimated the cost of compliance to be $500/tank with one tank for every 2 wells.

The Department agreed that changes to § 78.56 to remove the requirement to install equipment to prevent unauthorized access by third parties are appropriate for conventional operations.

The Department initially estimated the total cost of this provision to be between $53,600 and $6,670,000 but since this provision has been eliminated, the total cost is $0.

The total new cost of this provision is $0.

Minimum 30 mil liner thickness unless thinner material is demonstrated to be equally protective (§ 78.56(a)(8))

The final rule requires that pit liners for temporary storage have a thickness of at least 30 mils and allows for the liner manufacturer to demonstrate that a thinner liner is equally protective. Prior to this revision, § 78.56 did not include any specification for minimum liner thickness and only included a requirement for a "synthetic impermeable liner." However, § 78.62 relating to disposal of residual wastes in a pit has required the use of a 30 mil liner or an alternate material if approved by the Department since Chapter 78 was initially promulgated in 1989. The Department acknowledges that when disposing of cutting by land application, a liner thickness is not specified but the Department notes that disposal of cuttings in a pit is far more common than land application. The Department has approved a number of liner products with a 20 mil thickness since Chapter 78 was initially promulgated but does not believe that the exception should define the rule. Due to these requirements, the Department believes that conventional oil and gas operators should already using 30 mil liners or an approved alternative most of the time.

The Department received comments on this provision stating that it was unnecessary and would increase costs of pit liners by over 100%. The comments specifically suggested that the price of a pit liner for a conventional operator would increase from $915 to $1864 if a 30 mil liner was required. The commenter did not provide detailed specifications for the liner described but it was indicated that the pits used in conventional well operations are typically no larger than 10 feet by 30 feet and hold less than 4,200 gallons. The liner required for a pit of that size is conservatively 650 ft^2. Based on liner pricing data available to the Department, the commenter is clearly not basing the cost estimates of $915 for 20 mil and $1,864 for 30 mil on what the commenter describes as a typical pit used in conventional well operations. In fact, the cost data appear to the Department to be based on providing a liner for a much larger pit, possibly as large as 6,000 ft^2 or 9 times the area of a pit identified by the commenter to be typical. A pit requiring a liner of 3,800 ft^2 size has been represented to the Department by the Conventional Oil and Gas Advisory Committee (COGAC) as the largest pit used during conventional operations in Pennsylvania. The Department believes that the example given by the commenter is an extreme example and is therefore not an accurate representation of the impact of a 30 mil liner requirement on the conventional oil and gas industry.

The Department did not initially assign a cost to this change in the regulatory analysis form developed for the proposed rulemaking. The following cost estimate is based on the cost difference between 20 mil and 30 mil liners. The Department acknowledges that operators may have bene using liners thinner than 20 mil in some cases but the Department does not believe that liners thinner than 20 mil generally have sufficient strength and thickness to maintain the integrity of the liner. Therefore, liners thinner than 20 mil were not considered. In order to provide a cost estimate, the Department reached out to a number of Pennsylvania based liner suppliers for pricing data. The most expensive provider quoted a price of $\$0.24/ft^2$ for 20 mil HDPE and $\$0.40/ft^2$ for 30 mil HDPE. For a typical conventional pit this amounts to a cost difference of $104. This price includes material costs only because install costs for both materials is equivalent.

$650ft^2 \times (\$0.40-\$0.24) = \$104$

The Department estimates that conventional operators dispose of drill cuttings in a pit about 75% of the time. Since operators that are using pit disposal are already required to use a 30 mil liner or an approved alternative, as has been the case since 1989, this new provision does not represent a new cost to 75% of new wells drilled. In addition this provision is not written in a manner to require retroactive application so no cost is assigned to pits existing prior to promulgation of the rule.

$104 x 1,334 x 25% = $34,684

The total new cost of this provision is estimated to be $34,684 per year.

Minimum pit slope of 2:1 or flatter (§ 78.56(a)(9))

When originally drafted, the Department included a requirement that temporary pits must have an inside slope 2:1 (horizontal: vertical) or flatter. The Department received significant public comment on this proposed requirement indicating that typical conventional pits use vertical walls and that this provision would require a significant deviation from typical practice. The Department did not initially assign a cost to this provision but commenters from the conventional industry estimated the additional cost to be between $5,000 and $25,000 per well, depending on topography. This would result in a total cost increase of between $6,670,000 and $33,350,000.

As a result of these comments, the Department ultimately removed the minimum slope requirement from the final rulemaking. Instead, the final rule continues to allow conventional operators to construct pits with steep inside slopes provided that the pits have an aerial extent of less than 3,000 ft^2 and volumetric capacity of less than 125,000 gallons. A pit of this size has been represented to the Department by the Conventional Oil and Gas Advisory Committee (COGAC) as the largest pit used during conventional operations in Pennsylvania. For larger pits, the rule requires the operator to obtain a site specific approval from the Department prior to constructing the pit. This revision will allow continued use of conventional pits at well sites, prevent an unnecessary increase in the footprint of pits and provide appropriate protections to the environment when operators require the use of large pits.

As a result of these revisions, the estimated cost increase for typical conventional operations is $0.

For pits larger than the thresholds described above, the total additional cost is anticipated to be negligible because pits of this size are rarely used by the conventional industry.

The total new cost of this provision is estimated to be $0.

Inspection of pit liner prior to utilizing pit to store waste (§ 78.56(a)(12))

This section requires conventional operators to inspect pit liners and repair all damages or imperfections prior to placing material in the pit. This is a new requirement which the Department estimates will take 1 hour of work time to complete if the liner is not damaged. There is no required paperwork associated with this requirement. The Department acknowledges that more work time will be necessary to comply in the event that a liner is found to be damaged but has not associated costs with repairs because repairs are necessary to comply with many other long-standing provisions in § 78.56 including § 78.56(a)(8)(i) which requires the liner to have a very low permeability and § 78.56(a)(8)(iv) which requires sections of the liner to be sealed together to prevent leakage.

The Department assumes that each well will have 1 pit liner to inspect at a labor rate of $30/hr and that this provision will not be applied retroactively

1,334 x 1 hour x $30/hr. = $40,020

The total cost of this provision is estimated to be $40,020 per year.

Secondary Containment for all aboveground structures holding brine or other fluids (§ 78.57(c))

When the rule was proposed, the Department estimated the cost to add secondary containment for all aboveground structures holding brine or other fluids to be $4,002,000. This estimation assumed 1 secondary containment structure per well and estimated a cost of $3,000 per containment structure.

$3000 x 1,334 = $4,002,000

Commenters correctly pointed out that the rule also requires secondary containment to be installed for all replaced and refurbished tanks as well as new. Commenters from the conventional industry estimated that tanks are refurbished or replaced at a rate of 7.5%/year. Based on an estimated 150,000 aboveground storage tanks in service, this equates to a refurbishment and replacement rate of 11,250 tanks/year. The commenters also estimated that 50% of the refurbished or replaced tanks will require new containment. The Department presumes these estimates to be accurate. Using these estimates, the updated cost of compliance is $20,877,000.

$3000 x 1,334 = $4,002,000

150,000 x 0.075 x 0.5 x $3,000 = $16,875,000

$4,002,000 + $16,875,000 = $20,877,000

The total cost of this provision is estimated to be $20,877,000 per year.

Identification of Underground Storage Tanks (§ 78.57(e))

When initially proposed, the rule prohibited the use of underground or partially buried storage tanks for storing brine. Under the proposed rule 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 provision because the cost was dependent on the number of buried tanks across the Commonwealth and the Department was unable to estimate the number of buried tanks at that time. This section also required operators to provide a list of all affected tanks to the Department within 6 months of when the rule became final. The Department estimated the cost to provide a list of all affected tanks to the Department within 6 months of the rulemaking becoming final to be $20,000.

The Department received significant public comment on this provision from conventional oil and gas operators. The Department received numerous estimates of the number of existing underground or partially buried storage tanks ranging from 2,000 to 150,000. Conventional operators argued that with potentially 150,000 buried tanks the cost to remove each tank and the cost to replace tanks that will be damaged in the removal process was significantly greater than the Department had considered when drafting the Rule. In addition, operators indicated that the act of burying tanks is done to provide freezing protection for produced waters in the winter and to allow water and oil to be more easily separated. As a result of public comment, the Department has amended the final rule 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 the final rule 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 (§ 78.57(f)-(g))

Subsections 78.57(f)-(g) implement 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. Commenters argued that this requirement is too costly to comply with and estimated a total cost to provide corrosion protection to all 175,000 existing tanks to be approximately $224,525,000. The commenters did not provide a specific cost breakdown for how that cost was derived.

The Department does not agree with the cost estimate. First, the estimate assumes that all existing tanks that are currently utilized by the conventional oil and gas industry are in need of cathodic protection and corrosion protection. This assumption is false because it is common for the conventional oil and gas industry to utilized plastic tanks which do not require corrosion protection to meet these requirements. Second, the final rule 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. So to apply the projected costs to all existing tanks is not an accurate portrayal of the true cost of this provision.

Additionally, 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 table below, the estimated costs for providing corrosion protection is less than half the cost of a new tank), the Department believes that it would behoove conventional oil and 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	Corrosive Protection Protection	Ratio of Cost of Corrosion Protection to Replacement
25 bbl.	$1,800.00	$350.00	$450.00	0.44
50 bbl.	$2,200.00	$350.00	$650.00	0.45
100 bbl.	$3,451.00	$350.00	$1,200.00	0.45
140 bbl.	$5,144.00	$350.00	$1,300.00	0.32
210	$6,083.00	$350.00	$1,600.00	0.47

Finally, this requirement is a statutory requirement under section 3218.4(b) of the 2012 Oil and Gas Act. As noted above, §§ 78.57(f)-(g) simply implement this requirement. The Department has also explicitly removed 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 non-metallic 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.

Quarterly Maintenance Inspections (§ 78.57(h))

Sections 78.57 and 78a.57 impose 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 Department initially proposed that all inspections should be conducted monthly, which the same frequency as required by the Department's storage tank regulations. In response to comments, the Department has amended § 78.57(h) to reduce the frequency of inspection from once per calendar month to once per calendar quarter to allow coordination between tank inspections and mechanical integrity assessments required under § 78.88 which requires wells to be inspected on a quarterly basis. This change will have the effect of reducing the burden on conventional operators while ensuring that storage tanks for produced fluids on well sites are inspected periodically. The Department received significant public comment on this requirement from conventional oil and gas operators indicating that this requirement would impose significant cost burdens on the conventional industry. Commenters estimated that inspection of each tank would take 1 hour on average at a labor rate of $30/hr. Commenters estimate that there are approximately 175,000 tanks utilized by conventional operators resulting in a total estimated annual cost for monthly inspections of $63,000,000 and $15,750,000 for quarterly inspections. The Department disagrees with this cost estimate.

The quarterly 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, resulting in a total annual cost of $5,250,000.

175,000 tanks x 4 inspection x $30/hr. x 0.25 hrs. = $5,250,000

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 large spill could cost more the total annual cost to inspect all storage tanks utilized conventional oil and gas well operators.

The estimated new annual cost of this provision is $5,250,000.

Radiation Protection Action Plan (§ 78.58 (d))

The Department has added § 78.58(d) to this rulemaking which 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. 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 must 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 does not believe that this provision will result in any significant new cost to conventional operators because conventional operators do not generally conduct processing on well sites.

To the extent that a conventional operator does conduct processing under § 78.58 and is required to develop a radiation protection action plan, the Department estimates that development of a plan will cost $10,000. The Department also believes that the majority of conventional operators would need only one plan to cover their operations. The total cost of this provision is dependent on the number of operators that conduct onsite processing and require development of a radiation protection action plan. The Department does not expect typical conventional operators to conduct onsite processing which would require development of such a plan but acknowledges that some number of operators may wish to conduct such activities.

The estimated total cost for this provision is $0 for typical conventional operations

Well Development Impoundment Construction Standards (§§ 78.59a, 78.59b)

In the final rule, §§ 78.59a and 78.59b 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 conventional operators indicating that these requirements were too expensive to comply with and would result in conventional operators being required to close existing impoundments at great expense for no environmental benefit. Commenters presumed that conventional operators would not be able to meet the requirements and would have to abandon all of their existing well development impoundment. Commenters then estimated that in the absence of well development impoundments, the additional cost of trucking water would cost $1,000 - $1,500 per well and that costs would be imposed on approximately 10% of wells drilled. This equates to a total new cost of $133,400-$200,100 per year for new wells. In addition, commenters noted that existing wells still have some need for freshwater and estimated that without use of well development impoundments, the new cost to be $100,000 per year for a total cost of $233,400 - $300,100 per year. One commenter estimates that 1,000 well development impoundments are currently operated by conventional operators and all would have to be closed a cost of $12,500 per impoundment for a total cost of $12,500,000. The Department does not agree with these estimates.

The Department does not believe that the majority of the ponds would be regulated under these provisions, as stated by one commenter. The same commenter describes these ponds as "*a freshwater source only, and no liquids are returned to or placed in the pond, other than groundwater. The ponds are traditionally small—on average a few dozen feet in width and ten or twelve feet in depth. The ponds have the same character as the many farm ponds that dot the landscape, and in addition to serving the above functions the ponds provide the recreational and wildlife benefits that any other small farm pond would, including fish and animal habitat.*" Based on this description these ponds seem to be better described as water sources than well development impoundments. To the extent that operators are constructing collection or intake dams for water sources, it is not the intent of the final rule to regulate those structures as well development impoundments. Based on the information provided by commenters, the Department believes that, at most, only a very small fraction of the 1,000 existing structures commenters interpreted to be well development impoundments will be impacted by the rule.

The cost associated with this provision is dependent on the number of existing facilities impacted. In order to develop a conservative cost estimation, based on the descriptions and information provided by conventional operators, the Department assumes that less than 5% of the 1,000 structures meet the description of well development impoundment and would be closed at a cost of $12,500 per impoundment.

1,000 x 5% x $12,500 = $625,000

It is also very likely that no existing facilities are impacted, in which case the cost is $0.

In addition, since at least 950 of these ponds will remain, the Department estimates that the costs associated with servicing existing wells will be reduced to $5,000 per year. The Department has not assigned a cost to future construction of new well development impoundments because conventional operators have indicated that they will not construct them.

Finally, the rule also requires operators to register the location of well development impoundments with the Department. Assuming a total of 50 existing well development impoundments, the Department estimates a total cost of $4,500.

The total cost of this provision is estimated to be between $0 and $634,500 for the first year and between $0 and $5,000 annually thereafter.

Centralized Impoundment Requirements (§ 78.59c)

The final rule requires conventional operators to close any existing centralized impoundments within 3 years of the implementation date of the final rule or obtain a permit from the Department's waste management program in the same time frame. The rule also requires any new centralized impoundment to be permitted by the waste management program. The cost of this rule is dependent upon the number of centralized impoundments that are impacted. No conventional operators currently hold permits for any centralized impoundments so to the extent that a conventional operator has a centralized impoundment, they are operating unlawfully. In addition, the Department does not anticipate conventional operators to construct any new centralized impoundments in the future.

The total new cost of this provision is $0.

Verifying that the bottom of the pit is 20" above the seasonal high groundwater table (§ 78.62(a)(9))

Section 78.62(a)(9) (relating to disposal of residual wastes – pits) requires operators to determine that the pit meets this requirement prior to using the pit. The determination must be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The Department notes that the rule does not exclusively require this determination to be made by a soil scientist but instead it allows the determination to be made by a soil scientist or other similarly trained person. The Department believes that training can be provided to conventional oil and gas operators to ensure they have the skills necessary to accurately identify the seasonal high groundwater table and comply with this requirement without having to hire a professional soil scientist in all cases. In addition, since 1989, in order to ensure that they were in compliance with this requirement, conventional operators must have been conducting an evaluation of the soils beneath the bottom of their pit locations.

To develop a cost estimate for this provision the Department will assume that all conventional well sites utilize a pit. However, this assessment is only required when the operator will dispose of residual wastes on a pit and is not required when the operator disposes of residual wastes off site or by land application. The Department attempted to use waste reporting data required under § 78.121 as a basis for the determination of how operators dispose of drill cuttings but found the available data to be lacking due to non-compliance with reporting requirements by conventional operators. Since data available to the Department is not representative of field practices, the Department will rely on field experience along and estimate that cuttings are disposed in a pit 75% of the time.

The cost of this provision ranges based on whether the operator obtains training and makes the determination in house or hires an outside consultant to make a determination.

<u>In House Determination</u>

It is the intent of the Department to provide training to operators to allow them to meet the requirement of being a similarly trained person. Since, as described above, the only new requirement is to verify and document that the bottom of the pit is 20" above the seasonal high groundwater table and operators must have been conducting investigations since 1989, no additional work time is assigned to the investigation. Therefore, the only new burden associated with this provision is the time spent filling out the form to document the determination. The Department estimates this should take 15 minutes to complete. The Department is using the labor rate provided by the conventional industry when calculating the cost of completing this work.

1,334 x 0.75 x 0.25hrs x $30/hr. = $7,504

Outside Consultant

If an operator chooses not to or is unable to obtain training, they may hire an outside soil scientist to conduct the investigation and complete the paperwork. Since, as described above, the only new requirement is to verify and document that the bottom of the pit is 20” above the seasonal high groundwater table and operators must have been conducting investigations since 1989, no additional work time is assigned to the earthwork required for the investigation. Therefore, the only new burden associated with this provision is the time spent by the soil scientist for conducting the investigation and filling out the form to document the determination. The Department estimates the cost to hire a soil scientist to be $750-$1,000 per day. With proper planning, operators would be able to utilize the soil scientist for the entire day to do multiple determinations. The Department estimates that a soil scientist would be able to complete 4 determinations on average, including paperwork in the time allotted. This estimate takes into account the fact that conventional well pits are typically no larger than 10 feet by 30 feet and hold less than 4,200 gallons. A pit of this size has a depth of approximately 2 feet and would necessitate digging a pit to a depth of only 3 feet, 8 inches to ensure the season high groundwater is 20 inches below the bottom of the pit. Digging to this depth is generally very easy to accomplish with earth moving equipment commonly used by conventional operators.

In addition, since the regulation allows for the use of other similarly trained people, an operator may hire an outside consultant that is not a professional soil scientist but is appropriately trained to meet the requirements at a lower rate. For example, many local sewage enforcement officers are appropriately trained to meet these requirements but do not command the pay rate of a professional soil scientist. Conservatively, the Department estimates that other similarly trained people are available for hire for $750 per day or less.

The cost of this provision varies depending on how efficiently consulting services are utilized. If professional soil scientists are hired at a daily rate and used to make only 1 determination the cost is estimated to be $1,334,000.

1,334 x 0.75 x $1,000 = $1,000,500

If a consultant is hired at a daily rate and used to make multiple determinations, the cost would be reduced. The Department believes that 4 determinations in a day is a reasonable conservative estimate.

(1334 ÷ 4) x $750 x 0.75= $187,594

The total annual cost of this provision if an outside consultant is hired is estimated to be $187,594-$1,000,500.

The total annual cost of this provision is estimated to be $7,504-$1,000,500.

Alternative Waste Management (§ 78.63a)

This section seeks to codify 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.

Site Restoration (§ 78.65)

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 existing 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", Document No. 800-2100-008, which was finalized on December 29, 2012. The revisions to § 78.65 in the final-form rulemaking were also intended to address comments on this section that indicated continuing confusion regarding what constitutes "restoration" as the term is used both in Chapter 78 as well as in Chapter 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, inter alia, of § 102.8(g). Areas not restored include areas where there are permanent structures or impervious surfaces.

The Department received numerous comments from conventional operators on this section indicating that it is inappropriate and would impose new costs on the conventional operators that are so enormous that they would put small, independent well operators out of business. Commenters estimated the total new cost of this section to be $22,000-$84,000 per well pad. A cost breakdown is provided below.

- Engineering services to prepare PCSM Plan satisfying §102.8(g): $10,000 - $15,000.
- Engineering services to prepare NPDES Permit application: $2,000 - $5,000.
- Construction cost for storm water best management practices only: $10,000 -$50,000.
- Detailed topographical survey: $2,000 - $4,000 (if not provided)
- Wetland determination, ecological screening, and environmental permitting: $2,000 - $10,000 depending on location, amount of disturbance, and type of permit needed.

The Department does not agree with this cost estimate. This section is intended to provide clarity for implementing existing requirements from both the 2012 Oil and Gas Act and Chapter 102. To the extent that an operator would incur the costs listed above, they would incur those costs regardless of the status of § 78.65 because they are costs associated with complying with the 2012 Oil and Gas Act and Chapter 102.

The estimated new cost associated with this section is $0.

Reporting and remediation of spills and releases (§ 78.66)

Section 78.66 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 rule, 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. The final rule 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 3-4 times the alternative process. Commenters 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. Commenters did not provide any specific details to fully explain the differences in their estimated costs. Commenters 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 § 78.66 include 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 rule is that operators must 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 commenters 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 represent 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 must 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 (§ 78.67)

Subsection 78.67(b) require the registration of the location of existing borrow pits within 60 calendar days after the effective date of the rulemaking and registration of new borrow pits before there are built. This will be done electronically through the Department’s website. 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.

Subsection 78.67(a) requires an oil and gas operator who owns or controls a borrow pit that does not require a permit under the Noncoal Surface Mining Conservation and Reclamation Act (NSMCRA) under the exemption in § 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. Commenters argued that the costs of this requirement are so high that conventional oil and gas operations would not be able to comply with them. Commenters provided the following table summarizing what they believe to be new costs imposed by this provision.

Requirement	**Cost**
License	$300.00
Sign	$500.00
Soil Tests	$1,500.00
Seeding	$500.00
Inspection (one-time)	$300.00
Silt fencing	$3,000.00
Sedimentation Ponds	$5,000.00
TOTAL	$11,100.00

The Department disagrees that the costs listed by the commentator represent a new cost to operators. The majority of the costs listed including soil tests, seeding, silt fence and sediment traps and basins are associated with complying with the Clean Streams Law and all oil and gas operators are currently required to comply with the Clean Streams Law. The costs that commenters attribute to sign and license are not fully explained but the Department presumes that the license cost is in reference to requirements in Chapter 77 to obtain a blasting license prior to conducting blasting. The Department does not believe that this represent a new cost to the conventional well industry. Operators who conduct blasting should already have the appropriate license to do so under Chapter 210. The Department presumes that the cost that commenters attribute to sign are based requirements in § 77.502 to display signs on the access roads to mining operations. The Department does not believe that this requirement is a performance standard under Chapter 77, Subchapter I and therefore does not represent a cost to operators under this section.

The exemption in § 3273.1(b) of the 2012 Oil and Gas Act was taken verbatim from the original 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.

<u>The total cost on the entire regulated community is estimated between $634,500 and $28,622,568.</u>

Unconventional Operators Savings
<u>Assumptions</u>

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

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

DEP assumes there is an average of 3 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 regulation must be factored on a well site basis, not on a per well basis. Many of the processes proposed for regulation in this rulemaking include activities integral to the operation of several wells and even several well pads.

2,600 wells permitted x 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**

<u>Savings Estimates</u>

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

The rulemaking will require applicants to submit well permit applications through the Department's website electronically. This will achieve greater efficiency and time management on the Department's end and will also save operators in postage.

2,600 permits x $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 completely. This proposed provision 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 2012) of approximately 10 properties.

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

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

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

1 renewal = 6.3% of permits
2 renewals = 0.7% of permits
3 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 2nd time is eliminated by this rule. Well permits fees for unconventional wells are either $4,200 for vertical wells and $5,000 for non-vertical wells.

0.7% x 2,600 x $4,200 = $76,440
0.7% x 2,600 x $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 $21,700,000. Upon further evaluation, since the well site restoration extension provisions are established by Act 13, any savings that may be realized by this provision are based on statutory provisions and not this rule.

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

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

Conventional Operators Savings
<u>Assumptions</u>

DEP estimates based on past trends that there will be around 2,000 conventional wells permitted each year for the next 3 years.

On average, about 2 out of every 3 permitted conventional wells are drilled.

There is typically only 1 conventional well per well site.

2,000 permitted wells x .667 drilled rate = 1,334

<u>Savings Estimates</u>

Electronic Submission of well permits (§ 78.15(a))

The rulemaking will require applicants to submit well permit applications through the Department's website electronically. This will achieve greater efficiency and time management on the Department's end and will also save operators in postage.

2,000 permits x $5 savings = $10,000

Electronic Submission of water surveys as one package

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 provision 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 conventional well site will fall within the 1,000-foot range (as specified by the 2012 Oil and Gas Act) of approximately 4 properties.

1,334 well sites x 4 properties (avg.) x $5 postage savings = $26,680

Two-year permit renewal term (§ 78.17)
The final rule 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, conventional well operators obtain well permit renewals at the following rates.

1 renewal = 11.2% of permits
2 renewals = 1.6% of permits
3 or more renewals = 0.1% of permits

Since the first renewal will be issued for a period of 2 years, the cost to renew permits for the 2nd time is eliminated by this rule. Well permits fees for conventional wells are $465 on average.

1.6% x 2,000 x $465= $14,720

Therefore, the total savings of this provision is estimated to be $14,720.

The estimated savings of this regulation on conventional operators is approximately $51,400 annually.

Pipeline/Midstream Companies Savings

<u>Assumptions</u>

There are approximately 100 Horizontal Directional Drilling (HDD) operations annually.
These operations use approximately 25,000 gallons of drilling fluids to conduct HDD operations.

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

Disposal costs = $.12 per gallon

Recycling and on-site application of gathering line HDD fluid discharges and returns (§ 78.68a(k))
2,500,000 gallons x .12 = $300,000

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

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

Local government costs and savings

The Department does not anticipate that there will be significant costs or saving to local governments. One area where organizations representing municipal governments raised a cost increase issue concerned the costs associated with the requirements for using conventional well brine for road stabilization or pre-wetting roads. The final-form rulemaking requirements in § 78.70 directly track the current road spreading for dust suppression and road stabilization program, and the requirements in § 78.70a for pre-wetting, anti-icing and de-icing largely mirror those requirements. The final-form rulemaking codifies these requirements but generally does not add new substantive requirements to the existing program. To the extent that municipalities are already working with oil and gas operators as the person who owns or maintains a road where road spreading will be conducted, the municipality should have little or no new costs. To the extent that a municipality wishes to initiate such a program, the requirements to do so today are virtually identical to the requirements of the final-form rulemaking.

Additionally, the public resource impact screening provisions in §§ 78.15(f)(2) and 78a.15(f)(2) may impose a cost on local governments. In accordance with §§ 78.15(f) and 78a.15(f), conventional and unconventional operators are required to provide public resource agencies 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 §§ 78.15(f)(1) and 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 the 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 the regulations. Increased field inspections and formal reviews are anticipated. More importantly however, there are provisions in the regulation package that will streamline the Department's operations that are anticipated to balance out any increased workload requirements. The following are measures included in the 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 Pennsylvania Fish and Boat Commission and landowners a copy of the site specific preparedness, prevention and contingency 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 commencement of pipeline horizontal directional drilling 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 website for all users. This will eliminate duplication of work.
- Allow for the one-time approval for pipeline horizontal directional drilling additives, which once approved, they will be posted on Department's website 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 rulemaking has been 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 the regulation 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

The final regulations include new planning, reporting and record keeping 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 record keeping required in the final regulations. The Department notes that some reporting and notification requirements are part of the existing regulations but the final-form rulemaking requires electronic submission, so not all of the items below are new reporting requirements (for example, permit application requirements in §§ 78.15 and 78a.15). The Department also notes that lists of pre-approved structures or methods will be maintained on the Department's website and operators utilizing those pre-approved items will avoid the need to meet these reporting requirements and use these forms. For example, once a processing method is approved under §§ 78.58(g) or 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 3218(d)(2)(i), submission of pre-drill well sampling data to the Department. §§ 78.52(d), 78a.52(d) at least 10 days prior to commencement of drilling.
- If an owner or operator chooses to dispose of residual waste 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. §§ 78.61(f), 78.62(a)5, 78.63(a)(5) and 78a.61(e).
- Operators road spreading of brine from conventional wells for dust control, pre-wetting, anti-icing and de-icing activities must notify the Department 24 hours prior to the activity. §§ 78.70(k), 78.70a(q)
- An operator who wishes to make changes to a plan for road spreading of brine for dust control, road stabilization, pre-wetting, anti-icing or de-icing must submit a plan to the Department for approval. § 78.70a(s)
- An operator of a borrow pit must register the location of the borrow pit. §§ 78.67(b), 78a.67(b)
- If an operator is using a borrow pit that doesn't fall under the permitting requirements of the Noncoal Surface Mining Conservation and Reclamation Act, they will be required to register the location of the borrow pit with the Department. §§ 78.67(b), 78a.67(b)
- Submission to the Department of an area of review report inclusive of a monitoring plan. §§ 78.52a(c), 78a.52a(c)
- If an operator wishes to use an alternate temporary storage practice, the operator must submit a request for approval to the Department. §§ 78.56(b), 78a.56(b)
- If modular aboveground storage structures are to be installed, a 3 business day notice to the Department is required. §§ 78.56(a)(4), 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. §§ 78.57(e) & 78a.57(e)
- Notice of planned use of previously approved or new processing method 3 business days prior to initiation. §§ 78.58(d) and (g), 78a.58(d) and (g)
- The Department must be notified electronically 24 hour prior to all HDD activities. §§ 78,68a(c), 78a.68a(c)
- The Department must be notified of any water supply complaints during Hydraulic Directional Drilling (HDD). §§ 78.68a(j), 78a.68a(j)
- The Department must be notified of any loss or discharge of HDD fluid during HDD activities. §§ 78.68a(i), 78a.68a(i)
- Proof of consultation with Pennsylvania Natural Heritage Program regarding PNDI and Pennsylvania Historical & Museum Commission regarding historical/archaeological sites must be provided to the Department. §§ 78a.69(c)
- 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 must provide electronic notification of the impoundment's GPS Coordinates to the Township and County in which the impoundment is located. §§ 78.59b(b) & 78a.59b(b)

- If an operator uses an open pit for storage of production fluids it must report such activity to the Department. §§ 78.57(a), 78a.57(a)
- The operator must notify the department within 3 business days of the deficiencies found during the monthly inspection of tanks. §§ 78.57(i), 78a.57(i)
- Surface Restoration Plan. §§ 78.65(b), 78a.65(b)
- The operator must demonstrate proof of compliance with §§ 102.8(l) and 102.8(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). §§ 78.65(b) and (b)(6), 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. §§ 78.65(a)(3), 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. §§ 78.15(a). 78a.15(a)
- An operator of a planned conventional or unconventional horizontal well which will be stimulated using hydraulic fracturing must develop and submit to the Department an area of review monitoring plan. §§ 78.52a(c)(3), 78a.52a(c)(3)
- An operator that constructed a well development impoundment prior to adoption of this rulemaking shall register the location of the well development impoundment within 60 days after the effective date of adoption of this rulemaking to the Department, through the Department's website, with electronic notification of the GPS coordinates, Township and County where the well development impoundment is located. §§ 78.59b(c), 78a.59b(c)
- An operator that constructed a well development impoundment prior to adoption of this rulemaking must provide to the Department certification as to whether the impoundment meets the requirements, any impoundment that does not meet the requirements shale be upgraded to meet the requirements. §§ 78.59b(b), 78a.59b(b)
- An operator who plans to close a well development impoundment must submit electronically to the Department a well development impoundment closure plan. §§ 78.59c(a), 78a.59c(a)
- An operator seeking to manage waste on a well site in any manner other than provided in §§ 78.56 – 78.63 or §§ 78a.56 – 78a.63 must submit a request electronically to the Department describing the alternate management practice. §§ 78.63a, 78a.63a
- A water purveyor withdrawing water from waters of the Commonwealth must submit to the Department daily withdrawal volumes on a quarterly basis, in stream flow measurements and/or other water source purchases. § 78a.69(c)(3)

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

- Consideration of Public Resources Form. §§ 78.15(f)(3), 78a.15(f)(3)
- Landowner Questionnaire & Instructions. §§ 78.52a(b)(3), 78a.52a(b)(3)
- Survey Plat & Instructions. §§ 78.52a(c)(1), 78a.52a(c)(1).

- Oil Well Certification Form & Instructions. § 78.52a(a)
- Intent to Produce Well Naturally Form & Instructions. § 78.52a(a)
- Proof of Operator Notification Form & Instructions. §§ 78.73(c), 78a.73(c)
- Stimulation Communication Notification Form and Instructions. §§ 78.73(c), 78a.73(c)
- Form/Questionnaire to submit to landowners for location of oil and gas wells. §§ 78.52a(b)(3), 78a.52a(b)(3)
- LP certification that pit and pit liner, as built, comply with § 78.56. § 78.56(a)(16)
- Quarterly or Monthly Tank Inspection Form. §§ 78.57 (i), 78a.57(i), respectively
- Form to request to process wastewater and drill cuttings. §§ 78.58(a), (e) and 78a.58(a),(e)
- Freshwater Impoundment Registration Form. §§ 78.59b(c), 78a.59b(c)
- Land owner request to waive restoration requirement. §§ 78.59b(g), 78a.59b(g)
- Mine Influenced Water Storage in a Freshwater Impoundment Form (must include parameters that demonstrate that water stored will not cause pollution). §§ 78.59b(h)(1), 78a.59b(h)
- Form for request to use solidifiers or other alternate practices for disposal of residual waste. § 78.62(c)
- Form for request to dispose of solid fraction of residual waste by land application in alternate manner. § 78.63(c)
- Extension of Drilling or Production Period Request Forms. §§ 78.65(c)(1), 78a.65(c)(1)
- Well Site Restoration Extension Request Form. § 78.65(d)(3)
- Written Consent of Landowner Restoration. § 78.65(d)(4)
- Post Drilling Restoration Report. §§ 78.65(e), 78a.65(e)
- Post Plugging Restoration Report. §§ 78.65(f), 78a.65(f)
- Landowner Consent Forms. §§ 78.65(g), 78a.65(g)
- Material Staging Area Setback Waiver Form. § 78.68a(e)
- Water Management Plan Approval Request Form. § 78a.69(c)
- Request for modification approval of a Water Management Plan. § 78a.69(c)
- Road Spreading Plan Application. § 78.70(a)
- Road Spreading Monthly Report. § 78.70(l)
- Pre-wetting, Anti-icing and De-icing Plan Application. § 78.70a(a)
- Pre-wetting, Anti-icing and De-icing Monthly Report. § 78.71a(r)

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 pre-drilling survey of their water supply, the presumption of liability provided by Act 13 will not apply. This provision is needed because this notice is required by Section 3218(e.1) of the 2012 Oil and Gas Act. This was a new requirement added in the 2012 Oil and Gas Act.

Sections 78.61(f), 78.62(a)(5) and 78.63(a)(5) requires conventional operators to provide notification to landowners after drill cuttings or other wastes are disposed on the site. This requirement is necessary to ensure that landowners are informed of where waste is disposed on their property and does not require landowner consent or prior notice.

Department notifications

In order to enhance the Department's field staff inspection efficiency, the 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 allowed the Department to effectively manage its resources and ensure timely inspections.

Three-day notifications are required for the following:

- installation of pit liner on conventional well site. § 78.56
- prior to commencing construction of a pit of greater than 250 ft^2 for servicing, plugging or recompleting a conventional well. § 78.56(e)
- prior to disposal of cuttings on conventional well sites. §§ 78.61-78.63, 78a.61
- prior to conducting onsite processing on both conventional and unconventional well sites. §§ 78.58, 78a.58
- prior to utilizing modular above ground storage structures on both conventional and unconventional well sites. §§ 78.56, 78a.56
- after noticing deficiencies in tanks during monthly or quarterly inspections on both conventional and unconventional well sites. §§ 78.57(h), 78a.57(h)

24-hour notice for Horizontal Directional Drilling (HDD)

In § 78a.68a(c), persons conducting horizontal directional drilling activities associate with pipeline construction relation to unconventional oil and gas operations must electronically notify the Department through its website at least 24 hours prior to beginning of any HDD activities, including conventional boring, beneath any body of water or watercourse. 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 the Commonwealth rather than the review and management of paper submissions;
- provide the public easy access to data via 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; and

- 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 in order 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 rule had to be made to the Department electronically. The Department received significant public comment from conventional oil and gas operators indicating that these requirements were excessive and overly burdensome for their operations. The Department has determined that moving to all electronic filing is appropriate and necessary for the Department to fulfill its mission. Therefore, the final 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 via 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 acknowledges 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 3222(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 water management plan. 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 the final-form rulemaking are intended to encourage such 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

Under section 5(a) of the Regulatory Review Act (71 P. S. § 745.5(a)), on December 4, 2013, the Department submitted a copy of the notice of proposed rulemaking, published at 43 *Pa.B.* 7377 (December 14, 2013), to IRRC and the Chairpersons of the House and Senate Environmental Resources and Energy Committees for review and comment.

Under section 5(c) of the Regulatory Review Act, IRRC and the House and Senate Committees were provided with copies of the comments received during the public comment period, as well as other documents when requested. In preparing the final-form rulemaking, the Department has considered all comments from IRRC, the House and Senate Committees and the public.

Under section 5.1(j.2) of the Regulatory Review Act (71 P. S. § 745.5a(j.2)), on _____________, 2016, the final-form rulemaking was deemed approved by the House and Senate Committees. Under section 5.1(e) of the Regulatory Review Act, IRRC met on __________, 2016 and approved the 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 Chapters 78 and 78a, are amended to read as set forth in Annex A.

(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 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 Legislative Reference Bureau as required by law.

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

John Quigley, Chairperson
Environmental Quality Board