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The Impact of Pennsylvania's Regulatory Framework on Conventional Oil and Gas Operations

September 1, 2013

The Mission of the Pennsylvania Grade Crude Oil Coalition is to advance local economies and energy independence by promoting shallow oil and gas production in a safe and environmentally sound manner.

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This White Paper examines the legal framework in which the Pennsylvania Department of Environmental Protection regulates, permits and authorizes conventional oil and gas operations in Pennsylvania. In addition to comprehensive changes being proposed for 25 Pa. Code Chapter 78, Subchapter C (which the Environmental Quality Board accepted on August 27, 2013 for publication as a proposed rule), the primary regulation of oil and gas operations in Pennsylvania, DEP has developed, proposed and finalized a variety of policies, permits and forms within the last twelve months that have hampered and will continue to hamper the conventional oil and gas industry, often with unclear environmental benefit. As it moves forward with its regulatory agenda, DEP must consider the cumulative impacts of this ever-increasing set of rules, permits and policies on conventional operations.

DEP should review and revise its regulatory proposals and must provide clear direction from the central office to the regional offices where discretion should be exercised to avoid the unnecessary imposition of costs and burdens to conventional operations, which have been a core Pennsylvania industry for over a century. Regulations developed for unconventional oil and gas operations are often inappropriate for conventional operations and impose a disproportionate regulatory burden on small businesses. In oil and gas regulations, one size does not fit all.

The Pennsylvania Independent Oil & Gas Association (PIOGA), the comprehensive trade association representing oil and natural gas interests throughout Pennsylvania, specifically endorses this White paper and unequivocally supports the recommendations.

Background: Conventional Operations Compared to Unconventional Operations

The Pennsylvania conventional oil and gas industry differs significantly from the unconventional industry in many ways, from the size of the site needed to drill a well to the resources needed to complete and bring it on line. According to DEP's *Act 13 Frequently Asked Questions*:

> A conventional gas well, also known as a traditional well, is a well that produces oil or gas from a conventional formation. Conventional formations are variable in age, occurring both above and below the Elk Sandstone. While a limited number of such gas wells are capable of producing sufficient quantities of gas without stimulation by hydraulic fracturing, most conventional wells require this stimulation technique due to the reservoir characteristics in Pennsylvania. Stimulation of conventional wells, however, generally does not require the volume of fluids typically required for unconventional wells.
> http://files.dep.state.pa.us/OilGas/OilGasLandingPageFiles/Act13/Act_13_FAQ.pdf

DEP's description focuses on one operational distinction between conventional and unconventional wells – the volume of fluids required for hydraulic fracturing. While this is an important factor distinguishing the two types of operations (with its obvious implications for water sourcing, transportation, reuse and disposal), there are other differences between conventional and unconventional activities and operations that merit consideration in the environmental/regulatory context:

- A typical well pad cleared for a conventional oil or natural gas well is more than <u>35 times smaller</u> than that of a typical deep well.[1] The conventional well pad is surfaced with a small amount of stone, often obtained on-site, as opposed to thousands of tons of surface materials applied at a deep well pad. Thus, the amount of site disturbance occurring at a conventional well site is qualitatively different, likened perhaps to the difference between the construction of a house and a shopping mall.

- The site needs at a conventional well are flexible (the one or two necessary water tanks can frequently be arranged on the access road rather than the location, etc.); thus the conventional site can be more flexibly adapted to existing site terrain. This flexibility significantly reduces site disturbance and thus erosion and sedimentation.

- A conventional drilling and completion operation involves a dozen or less heavy truck trips in and out as opposed to hundreds, or sometimes thousands, for deep wells, thus significantly reducing road requirements, sedimentation from road travel, and stress on local municipal roadways.

- The drilling and completion of a conventional well requires three to four days operation of just a few diesel engines (one or two small hydrofracture unit(s) as compared with ten or more larger units at deep wells, and two sand trucks as opposed to one hundred or more at deep wells) and thus the air quality impact at a conventional site is minimal. At a conventional site, engines typically run only for a few hours and generate a total hydrofracture horsepower of about 1500 hp, as compared to an unconventional site where engines might run for days and generate more than ten times as much horsepower.

- The scope of conventional well stimulation extends a few hundred feet into the oil and gas bearing strata rather than the several thousand feet involved in deep well stimulation. This different scope accounts for the qualitatively different equipment and water requirements.

- Wellhead pressures of new conventional wells are only several hundred pounds and quickly reduce to very low pressures. The vast majority of conventional wells in Pennsylvania operate at less than 50 psi. Wellhead pressures of new deep wells are measured in thousands of pounds and deep wells employ safety measures and equipment entirely unnecessary in the conventional well industry.

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[1] Unconventional well pads typically cover 5 *acres* or more during construction. A conventional well pad usually occupies only 5000 *square feet.*

- A conventional oil or gas well has a much smaller footprint in the production phase itself. Once construction is completed, conventional well sites are almost entirely restored, leaving only a single wellhead, pumpjack and other necessary equipment, and enough space to service and maintain the well.

- The typical production brine produced from conventional operations is less brackish than seawater. The typical production brine produced from unconventional operations is many times as saline as seawater.

Another critical distinction of the conventional industry is the cost to develop the wells, their lower production and the smaller return on investment compared to shale wells. Conventional wells have lower profitability than unconventional wells and are strongly influenced by oil and natural gas commodity prices and other market forces. When the cost to drill these wells increases, conventional wells become less viable. For the year to date, as of July 26, 2013, PADEP had received 1,611 well permit applications for unconventional wells, while receiving only 991 permit applications for conventional wells. http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/OilGasReports/2012/WEBSITE%20Weekly%20Report%20for%20Last%20Week.pdf. The number of conventional wells drilled in Pennsylvania has declined steadily since 2007, from a high of 4,836 wells drilled in 2007 to 2,002 drilled in 2009, to 1,272 wells in 2011, and to a projected approximately 700-800 wells to be drilled in 2013. The cumulative impacts of additional regulation arising from unconventional operations unnecessarily spilling over to conventional operations is responsible to a significant extent for the steady decline in the number of wells drilled.

In the long history of oil and gas production in Pennsylvania, the overall environmental impact of conventional wells, from construction through production to plugging, is minimal. Conventional operations, however, have been caught in the crossfire of increasing unconventional drilling activity in Pennsylvania, public anxiety about the potential impacts of hydraulic fracturing, and the rush or impulse to regulate – indeed hyper-regulate - this development activity. The following sections describe some of the more significant regulatory impacts on conventional operations in recent months and propose solutions to alleviate the cumulative impacts of such regulations on this vital Pennsylvania industry.

Recommendations to Ensure the Viability of the Conventional Oil and Gas Industry

A. DEP should restructure Chapter 78 to separate those regulations that apply exclusively to unconventional operations.

Given the stark differences in the nature of conventional shallow oil and gas activities and operations compared to unconventional oil and gas development, DEP should structure Chapter 78 in a manner that clearly identifies and separates the provisions that apply only to unconventional operations and activities.

Many of the new provisions in Act 13 focus on the operations and impacts of unconventional well development. For example, Act 13 provides for specific requirements for unconventional wells related to: permit application notification requirements and comment opportunities, notifications to DEP, water management plans, site location setbacks, presumptions of impacts to groundwater, containment requirements for unconventional well sites, recordkeeping requirements for flowback, air emissions, inspections and penalties. These provisions do not apply to conventional operations and any Chapter 78 rules to implement these new provisions could easily be placed into a new separate subsection for unconventional wells. This would assist not only industry in understanding its compliance obligations, but would be helpful to both DEP staff and the public as well.

The current effort to revise Chapter 78 for the implementation of these provisions creates the ideal opportunity to segregate the rules that apply only to unconventional operations. If not done in the current rule revision, this task would be much more difficult in the future.

B. Regardless of whether Chapter 78 is structured to create a new section for provisions that apply exclusively to unconventional operations, the rule must provide exceptions for conventional operations.

Many of DEP's Chapter 78, Subchapter C proposals, beyond those that apply exclusively to unconventional operations, would create significant additional obligations for conventional oil and gas operations that could very well eliminate the slim profit margin for many conventional wells. Examples of such proposals include new requirements for security or fencing of tanks storing brine or other substances, new pit slope and design requirements, new limitations on storage of production fluids, the prohibition against underground tanks, and requiring removal of any such tanks within three years, which is especially costly. See the attached Exhibit for specific citations to DEP's proposed Chapter 78 revisions that are particularly problematic for the conventional industry.

In accordance to requirements of the Regulatory Review Act, as amended on June 29, 2012, DEP is required to consider the impacts to small businesses from new regulation, including the legal, accounting and consulting compliance costs that would be incurred. Act 76 of 2012, Act of Jun. 29, 2012, P.L. 657, No. 76. Under the statute, DEP must consider the establishment of less stringent compliance requirements for small businesses throughout Chapter 78.

Consideration of the impacts to small businesses can include the establishment of less stringent schedules or deadlines for compliance or reporting requirements, the consolidation of compliance or reporting obligations, and the use of performance standards to replace design or operational standards. Of particular importance, DEP should give serious consideration to the exemption of small business from all or any part of the new requirements contained in the proposed regulation.

C. DEP's draft Spill Policy and its proposed revisions to Chapter 78 make significant changes that have the potential to impose substantial cost increases without corresponding environmental benefit.

DEP's proposed section 78.66 (Reporting and Remediating Releases) would require small spills of less than 42 gallons to be cleaned up and documented through the Land Recycling and Remediation Standards Act (known as Act 2) process outlined in 25 Pa. Code Part

250. It is critical to recognize that Act 2 was enacted to eliminate "environmental hazards on existing *commercial and industrial land* across this Commonwealth," and that the "reuse of *industrial land* is an important component of sound land-use policy that will prevent the needless development of prime farmland, open space areas and natural areas and reduce public costs for installing new water, sewer and highway infrastructure." Act 2, Section 2, Declaration of Policy. Thus, the policy and focus of Act 2 is to clean up and reuse industrial land. Although Act 2 cleanup standards are to be employed wherever DEP requires cleanup under certain listed statutes including the Clean Streams Law, the Oil and Gas Act is not a specifically listed statute to which Act 2 applies. Thus, Act 2 procedures and standards should not be casually adopted to the oil and gas fields without considering the implications, especially on the conventional industry.

Proposed section 78.66 substantially increases the time and costs for addressing small spills, costs that far outweigh any benefit to be realized in most circumstances. DEP should not require an attainment demonstration under the Act 2 process for small spills because that process can require many soil and groundwater samples over several months or years, which imposes significant cost to clean up a small spill and provides no meaningful additional environmental protection.

Requiring Chapter 250's statistically-based cleanup standards for all spills less than 42 gallons onto the ground or a well pad surface would bring a group of small spills, depending upon the substance spilled, into much more expensive remediation costs. Small spills (up to 10 gallons), whether brine or crude oil, are normally handled by immediately absorbing, vacuuming, or excavating a generous area around and under the spill, to visual, olfactory, and field metered standards. Onsite bioremediation *in situ* has been used successfully for many years and should be encouraged. The federal Environmental Protection Agency recognizes that bioremediation is a proven alternative tool that can be used to treat crude oil spills, has issued fact sheets and similar technical materials to guide on-scene coordinators response to such spills, and has recommended the evaluation of bioremediation as a cleanup option for crude oil spills in Pennsylvania.[2] Because such small spills have no real potential to pollute, this approach is environmentally sound and operationally efficient. There is no reason for DEP not to adopt it as an alternative.

Satisfaction of Chapter 250 statistical attainment documentation would require hiring consulting services, taking at least 10 soil samples of the spill area and background and 10 post-removal soil samples, with all of the associated costs, over and above the remediation method described above. The total cost for a small spill area, with consulting services and analysis, could easily reach $10,000 to $20,000. While spills are not desired or even commonplace, equipment failures occur. Valve failures, stuffing box rubber leaks, and the like can result in spills in excess of the 5 gallons contemplated in section 78.66, and with just a few of these per

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[2] See, e.g., *NRT Fact Sheet: Bioremediation in Oil Spill Response*, A.D. Venosa, U.S. EPA Region 4; and *Proposed Cleanup Guidelines for Small Crude Oil Spills using Bioremediation (Process Selection Flow Chart),* J. Brown (Lockheed Martin/REAC) and H. Allen (USEPA/ERT); and *Voodoo s. Science; The Practical Application of Bioremediation Techniques as a Removal Response Option at Oil Spill Sites in the Northwestern Pennsylvania Oil Patch,* V.E. Zenone, USEPA Region III (April 2004).

year the proposed regulations could add hundreds of thousands of dollars of additional expense per year. Conventional operations simply cannot bear such unjustified costs.

Perhaps a greater issue than the cost is the distraction of the operator's environmental staff from more important activities aimed at prevention of truly detrimental releases and conditions.

As for larger spills, persons who remediate spills at oil and gas sites in Pennsylvania have always had the option to utilize the Act 2 process to obtain liability relief. One problem presented by the draft Spill Policy and the Chapter 78 proposal is that there are no statewide health standards for chlorides, which may be a common constituent of spills related to oil and gas operations. Requiring compliance with Act 2 for brine spills potentially creates excessive burden and expense for oil and gas operators to develop background or site specific standards of attainment, with uncertain environmental benefit. By the time such standards and cleanup plans are developed, chloride impacts may have naturally attenuated to the point that further remediation is unnecessary or could do more environmental harm than good. This is not in the spirit of Act 2, which was intended to encourage voluntary cleanups that address actual risks and not require that every site be immediately returned to pristine condition. Site specific factors should be reviewed to allow bioremediation and natural attenuation for such spills.

In sum, any spill policy or rule must consider the harm that is being mitigated with the costs imposed for such mitigation. For example, standard industry practice for over one hundred years was to discharge brine to the ground surface and the overall effects of that practice were minimal because (i) the conventional industry generates much less (and less brackish) brine than the unconventional industry and (ii) conventional industry brine has not been observed to have any significant or lasting environmental effect. DEP must consider this historical knowledge and context before altering cleanup requirements, especially for small spills of substances that have low toxicity and are readily bioremediated, such as brine and crude oil.

D. DEP's PNDI Policy and proposed changes to Chapter 78 for the consideration of well permit conditions to mitigate impacts to public resources ignore <u>the status of the oil and gas mineral owner as the holder of the dominant estate</u>.

The "public resources" provision in Act 13 was already adopted by the legislature (in the Oil and Gas Act of 1984) at the time of the PA Supreme Court's decision in <u>*Belden & Blake Corp. v. DCNR*</u> in 2009. 969 A.2d 528 (Pa. 2009). In that case, the Pennsylvania Supreme Court affirmed the concept that any reconciliation of surface owner disputes, whether a private person or public entity, is through negotiation. *Belden & Blake* makes clear that a public surface owner cannot unilaterally impose conditions on the oil and gas operator.

In contravention of *Belden & Blake,* the last paragraph of 78.15 would allow the state to unilaterally impose permit conditions foregoing negotiation between the dominant tenant and the public surface owner. Regardless of its authority under Act 13 to "consider" impacts to public resources, DEP does not have unbounded authority to disregard well-established principles of Pennsylvania property law. Accordingly, DEP may not create a rule that allows public agencies to circumvent their limitations under the guise of protecting public resources. The Pennsylvania Supreme Court has already spoken to this precise question:

> A subsurface owner's rights cannot be diminished because the surface comes to be owned by the government, or any other party with statutory obligations, regardless of their salutary nature. . . . That is, whatever its admirable obligations to the public, as concerns the owner of private property, the government and its agencies must be held to the same standard as any other surface owner. DCNR may <u>seek</u> additional conditions because of its mandate, but is has no authority to <u>impose</u> them unilaterally without compensation. (emphasis in original)

969 A.3d at 532-33. Chapter 78 may not be used to create a permitting process that directly undermines these principles.

An additional problem with DEP's proposed revision to 78.15 is the cumulative nature of the obligations. The PNDI requirements for the protection of threatened and endangered species are time consuming and sometimes require modifications of well sites, activity times or dates, and other operational sequencing. There is a cost involved with paying a professional consultant to conduct the PNDI search and those costs increase when PNDI conflicts are encountered. DEP's proposed addition to consider and mitigate impacts to "special concern species" during the well permit process raises both legal and practical concerns because: 1) those species have never been designated as such under rulemaking by any government agency; 2) the number of such species in the PNDI database is three times as many as the threatened and endangered species combined; and 3) DEP's proposal would instantly elevate protections for hundreds of such species to the status of threatened and endangered species without any opportunity for public review. This proposal defies all principles of administrative law and rulemaking protections and is beyond DEP's statutory authorization under Act 13.

E. <u>Recent policy changes made to the approvals and permits required for erosion and sedimentation, as well as post-construction stormwater controls, significantly increase costs for conventional operations.</u>

The revised Erosion and Sedimentation Control General Permit, ESCGP-2, published on December 31, 2012, imposes several new obligations on the construction of oil and gas well sites from the prior version of the general permit. The various documents released at that time – the permit itself, the Notice of Intent, the new Erosion and Sedimentation Policy, the comment/response documents, etc. – create unclear obligations for various components of oil and gas operations, which do not seem to be consistent with the provisions and obligations of 25 Pa. Code Chapter 102. Generally, the permit imposes new costs and burdens during the application process (for infiltration testing, geotechnical studies, and post construction stormwater design calculations, for example) and in the end, requires a more extensive environmental footprint than had been required under the former ESCGP-1.

The conventional industry disturbs much less land than the unconventional industry, which should be considered when calculating the five acre threshold for ESCGP-2 permitting purposes. For example, a conventional operator may be able to prepare as many as 10 well sites and associated roadways in less than 5 acres. Conventional operators typically prepare a site and drill the well in a short time frame, and then restore the site and move on to the next site. Under past and current interpretation, DEP excludes conventional oil and gas activities from the scope of the ESCGP-2 on a "rolling 5 acre" basis. Under this approach, an ESCGP-2 permit is not required if an operator does not have more than 5 acres under disturbance on a particular project at any one time, regardless of the number of wells it drills. When revegetation is successful at a disturbed area, the operator may move on to the next area without having the first disturbed area count toward the 5 acre threshold for ESCGP-2 permitting purposes. This current practice should be confirmed in proposed regulations in the interest of providing regulatory certainty and in balancing economic impacts with environmental benefits.

In those cases where an ESCGP-2 permit is required for conventional operations, flexibility should be provided with regard to the calculation of the five-acre threshold for permits, as well as DEP's interpretation of minor deviations from plans that can be made without DEP approval or new plans. The conventional industry for many years has developed erosion and sedimentation plans using topographic maps. They are well suited for that purpose even though they are not as accurate as survey plats. DEP accepts this practice and recognizes that what is planned on paper is rarely exactly how an erosion and sedimentation control feature is built in the field. Consistent with this practice, for example, any deviation less than fifty feet should be allowed without additional review or plan revisions. Requiring licensed surveyors for minor changes simply adds unnecessary cost and delay to the process.

As for site restoration, Section 3216(e) of Act 13 requires well sites to be restored in accordance with the Clean Streams Law, for which the applicable regulations are found in Chapter 102. Section 102.8(n) of Chapter 102 exempts oil and gas activities from extensive post-construction stormwater design criteria that apply to other earth disturbance activities, such as commercial or industrial construction projects. The post-construction control requirements in section 102.8(b) of Chapter 102, which exempted well sites from certain requirements because of the very small post-construction footprint, balance environmental goals with practical limitations. Accordingly, compliance with Pennsylvania's Stormwater Management Act (Act 167) should not be required for conventional sites, which are required to meet express post-construction stormwater control standards under 25 Pa. Code Chapter 102.

F. Horizontal directional drilling (HDD) under small and intermittent streams <u>should be exempted from permitting or be given a permit by rule</u>

DEP's proposed new regulation for horizontal directional drilling in section 78.68a of the Chapter 78, Subchapter C regulations treats the conventional and unconventional industries the same when there are in fact significant differences between them. Conventional oil and gas wells can be spaced as closely as 300 to 600 feet apart. In Pennsylvania's mountainous and forested shallow oil and gas producing areas, it is not uncommon for conventional operators to directionally drill under several swales, depressions, and intermittent and very small streams in order to lay pipeline to these wells. Many of these swales and depressions are not blue line streams, and the intermittent and small streams are often dry during the summer months. By contrast, the unconventional industry typically clears 5 acres or more for one well site and then constructs the next site many miles from the first one. Pipelines can follow roadways or other corridors. The potential impact from each industry is very different.

The current permit requirements for HDD related activities under the Cleans Streams Law, the Dam Safety and Encroachments Act, and other Pennsylvania statutes protect the environment without being overly burdensome on conventional operators. Many of the requirements in proposed section 78.68a (e.g., compliance with Chapters 102 and 105) are already in place. But the proposed requirement for prior DEP approval of drilling fluid additives other than bentonite and water, the requirement of immediate notification, without exception, of the loss of circulation, and the requirement of prior notice to DEP before HDD begins simply add needless regulatory burdens on the industry. HDD activities under depressions, swales, intermittent and blue line streams should be exempted from this proposed additional regulation under Chapter 78 because the activities are already regulated under Chapters 102 and 105. Alternatively, at a minimum, a permit by rule should be made available for this activity.

G. DEP should limit a well permit applicant's obligation to notify municipalities to those municipalities that lie within 2000 feet of a proposed well.

Section 3211(b)(2) of Act 13 requires a well permit applicant to notify (among other entities) the host municipality and those municipalities that are "adjacent to the well." Notification must be done by certified mail. The proposed revisions to Chapter 78, Subchapter C do not address municipal notification. However, the notice should be limited to only those non-host municipalities whose municipal boundaries are within 2000 feet of the proposed well, rather than all municipalities that are contiguous to the host municipality, to avoid imposing unnecessary, time consuming and potentially significant costs on the conventional industry.

There are 2,563 municipalities in Pennsylvania. In the five-county northwestern Pennsylvania oil and gas field counties of Warren, Forest, Venango, McKean, and Elk alone for example, there are 101 individual municipalities. Many of these townships encompass significant surface area. If the notice requirement is interpreted to require notice to each of those municipalities that are contiguous to the host township, a permit applicant would have to send up to a dozen or more certified mail notices, including notices to municipalities which may be located many tens of miles or more from the well site. For example, applying for a permit drill a well in Mead Township, Warren County would require notice to thirteen different municipalities under this interpretation.

By contrast, the requirement to notify "adjacent" municipalities should be limited to those that are within a reasonable distance (i.e., 2,000 feet) of the proposed well location because the impacts of conventional well development are so much smaller than unconventional activities. There is no compelling reason to notify physically distant municipalities, given the small footprint of conventional development and its low impact on municipal roadways and services. A broader notice requirement simply imposes on the applicant the additional cost and delay of mailing certified letters. Current law and practice does not require notice to distant municipalities. The conventional industry and local government function fine without it. There is no reason to interpret Act 13 differently.

This position is legally justifiable. Act 13 does not define an "adjacent" municipality, but a dictionary definition of "adjacent" means "lying near to or close." *Webster's New Twentieth Century Dictionary, Unabridged* (Second Edition). DEP can legally take the position, consistent with Section 3211(b)(2) of Act 13, that municipal notice is limited to the host municipality and those municipalities whose borders are within 2,000 feet of the proposed well.

H. DEP's proposed Mechanical Integrity Assessment (MIA) guidance for reviewing casing and cementing standards ignores <u>fundamental differences in the way conventional wells operate.</u>

There is not a compelling need to impose significant new casing, cementing and inspection standards in view of the reported number of well integrity problems. Even if there is some justification, DEP's draft MIA forms and instructions for reviewing casing and cementing standards do not fully recognize fundamental differences in the way conventional wells are cased, cemented, and/or operated as compared with unconventional wells, or the disparate impact that proposed new inspection and other assessment standards will impose on the conventional industry.

DEP reportedly has recorded approximately 128 confirmed stray gas migration cases in Pennsylvania. Only 24 of these have any connection to well integrity issues, and of those, it is not clear whether the wells were operator-owned or orphaned. A failure of 24 wells out of the approximately 135,000 wells operating in the state – a "failure" rate of 0.02% – does not justify the proposed burden to industry generally or the conventional industry specifically.

The operating pressure of a conventional well is fundamentally different than that of an unconventional well. Conventional wells typically operate at only hundreds of psi of pressure or less, which means the surface shut-in pressure and surface producing back pressure inside the surface casing does not exceed the 0.433 psi standard set forth in 25 Pa. Code § 78.73(c). (If greater pressure than the 0.433 psi standard is encountered in a conventional well the industry practice is to introduce a second string of casing so that the surface casing is not exposed to that greater pressure.) This in turn means that if a shallow conventional well loses integrity, groundwater would migrate into the well bore, not the other way around where there would be a risk of gas or other fluids migrating from lower formations into fresh groundwater. Much of the DEP's commentary during the recent MIA meetings and workshops seems not to have fully appreciated this point or the economic impact that new MIA program will have on small businesses.

Also, proposed pressure testing cannot be done on thousands of conventional wells because they are produced at atmospheric pressure for which integrity pressure testing is not possible. This is another very significant difference from unconventional wells.

DEP estimates that annual inspection costs for 80% of the industry will be less than $1,000 with a potential start-up cost related to equipment purchases of less than $3,300. However, the operators representing the remaining approximately 20% of the industry – i.e., small operators and independents – operate most of the wells in Pennsylvania. The impact of the new MIA form is very significant to them. Using DEP's formula, it appears that a minimum of 1 additional employee may be required for every 500 wells. A conservative "all-in" cost to hire an inexperienced, entry-level employee would be approximately $65,000-$70,000 a year per 500 wells. Implementing the MIA guidance will be very work-intensive at the outset – educating existing technical staff (or creating a new position requiring additional team members) in inspection imperatives, constructing an inspection template compatible with the MIA form for each technician to complete quarterly in the field, and training an office position with some knowledge of well mechanics to transfer the data from the field to the electronic MIA form. DEP has not fully considered this significant economic impact.

Conventional production should be allowed to comply with Section 78.88 as it is written, and categorically excluded from the new MIA program, for all the reasons stated above.

I. DEP must conduct its small business review before <u>submitting the Chapter 78, Subchapter C proposal to EQB.</u>

DEP is under a legal obligation to ensure that the costs of new regulations, specifically the proposed amendments to Chapter 78, Subchapter C, do not outweigh the benefits. It is not apparent that DEP has met this requirement at this point.

As referenced above, the 2012 Regulatory Review Act requires DEP to consider the impact of its proposed rules on small businesses. In addition, by Executive Order and DEP policy, DEP must rigorously review a proposed rule, before it is published, in accordance with Executive Order No. 1996-1, 4 Pa Code Chapter 1, Subchapter FF, and the Policy for the Development, Approval and Distribution of Regulations (Doc. No. 012-0820-001). These require that:

- regulations address a "compelling public interest" and "definable public health, safety or environmental risks,"
- the costs of regulations do not outweigh the benefits,
- viable non-regulatory alternatives are explored and preferred over regulation; and that
- regulations "shall not hamper Pennsylvania's ability to compete effectively with other states."

There is no indication that DEP has evaluated these considerations fully in the proposed Chapter 78 revisions. The proposed revisions include numerous new obligations that would increase operational costs and complexity without clear justification or environmental necessity. The cumulative economic impacts of rules for which the costs exceed the benefits are of particular concern to the hundreds of conventional well owners and operators in Pennsylvania. We believe rules should not be proposed unless flexible regulatory approaches are considered or provided for small businesses in accordance with the law. This analysis must be a part of the proposed rule so that small businesses have the opportunity to review and comment on all proposed accommodations.

Conclusion

DEP is well aware that the conventional oil and gas industry is vastly different from the unconventional industry regarding the activities and perceived environmental impacts to be addressed by the proposed Chapter 78, Subchapter C regulations. DEP must thoroughly review the numerous broad, over-reaching and unnecessary requirements of this proposed rulemaking together with the cumulative effect of other recent policy initiatives threaten the continued viability of the conventional industry in Pennsylvania. All regulatory proposals and policies, as outlined in this White Paper and the Exhibit and going forward, should be carefully reviewed to ensure that the conventional industry is regulated in a manner that is consistent with the relatively benign environmental impacts from this industry over its one-hundred-fifty year old history of providing essential oil and gas resources to the Commonwealth and the nation.

Pennsylvania Grade Crude Oil Coalition

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EXHIBIT

Chapter 78 Provisions from which Conventional Operations Need Relief

Generally, the notification requirements in Chapter 78 are overwhelming. There are at least 35 references to notifications in the proposed rule. All such requirements should be reviewed with respect to their necessity related to conventional operations. One such example is the requirement to notify "adjacent" municipalities of a well permit application, as described above.

The following list provides examples and is not exclusive of other provisions from which relief is appropriate.

- Section 78.15 – Permit Applications
    - In addition to the objections to the PNDI policy and the consideration of special concern species in well permit applications described above, section 78.15 as drafted has no criteria to guide DEP on how it will ensure that the requirements of Section 3215(e) – i.e., ensuring optimal development of oil and gas resources and respecting private property rights of oil and gas owners – will be met.

    - DEP continues to revise its forms to address unconventional operations without fully considering the circumstances of the conventional operators.

- Section 78.51 – Protection of water supplies
    - The requirement to replace water supplies affected by drilling with water that meets Safe Drinking Water Act standards, where the pre-existing water quality was below those standards, imposes a burden on the oil and gas industry that no other industry suffers, provides an unreasonable windfall to landowners, and creates significant implementation problems and unintended consequences.

    - By not excluding diminution claims under certain circumstances, it also ignores the rights of OGM owners to use water for their operations under the common law through deeds and leases which give that right to the OGM owners.

- Sections 78.52a and 78.73 - Abandoned and orphaned well identification
    - The requirement to identify abandoned and orphaned wells before hydraulic fracturing, as a means to prevent possible subsurface communication pathways, ignores the fact that stimulating conventional wells typically propagates fractures that extend only a very short distance, making the risk of communication very small. The conventional industry has successfully stimulated shallow wells for

many years without formal abandoned and orphaned well identification procedures and without widespread environmental problems.

- Sending questionnaire to landowners raises unclear obligations and outcomes, in the cases, for example, where landowners refuse to answer questionnaires.

- There is no definition of what it means to "alter" and abandoned well. Conventional operators could be held responsible to plug abandoned or orphaned wells that they did not affect, depending on DEP's interpretation of "alter."

- Section 78.55 – Planning and Emergency Response
  - The requirement for site specific PPC plans for conventional well sites is unnecessary. A generic PPC plan is and has been a sufficient guide on how to handle materials on a well site and respond to releases or threatened releases, because (i) well sites are small, (ii) the volume of material that could be released from an accidental spill is small, and (iii) there are fewer different materials on site at conventional vs. unconventional operations to manage. A generic PPC plan can address materials handling very adequately at all of an operator's sites.

- Section 78.56 – Temporary Storage
  - There are several problems with this proposed section, including the meaning of "regulated substances" – i.e., does it refer to materials commonly used at a well site or to the all-encompassing definition used in Act 2?

  - The proposed standards for pit construction, location, liners and liner permeability, and pit slopes all add significant cost to conventional operations and in some cases would cause greater environmental damage than current practices. For example, a pit slope of 2:1 is impractical in many of the tight physical locations where shallow wells are drilled. Pit collapse at conventional sites has not been a problem, in part because the pits are small and they are usually open only for a short period. Complying with this standard will require more land and timber to be cleared simply for the pit.

  - Security, fencing and inspection measures are unnecessary and/or impractical for many conventional sites. Unlike an unconventional well pad where operations are concentrated in one area that may be securable, a single conventional producer may operate literally hundreds of small well locations and tank batteries (which may be a single storage tank or a collection of tanks) in remote areas spread across tens of miles or more. Retrofitting conventional operation tank batteries with retractable ladders would not be a reasonable measure to prevent unauthorized access in most cases because of the cost to retrofit hundreds of such batteries.

- Section 78.57 - Production fluids
  - The conventional industry for years has commonly stored brine and produced fluids generated during the operation of a well in open top structures without

significant incident. These wells do not generate nearly the volume of produced fluids typical of unconventional wells.

  - Underground tanks have been vital to conventional operators to store fluids. For example, in flatland areas, aboveground collection tanks are used to phase-separate brine from oil that is produced by wells. Brine settles by gravity to the bottom of the collection tank. The practical way to drain it from the collection tank is to let it flow, again by gravity, to a buried underground tank, from which it can be removed for disposal or beneficial reuse. Such storage is appropriate because of the low toxicity and the much smaller volume of fluids generated. Requiring the removal of all USTs within 3 years of the regulation imposes an excessive and unnecessary cost.

- Section 78.58 - Onsite processing
  - The proposed regulatory approvals for onsite activities are too limiting and conflict with Act 13, which provides that onsite activities shall comply with Act 13 in lieu of the Solid Waste Management Act.

  - The proposed characterization of sludge or waste from processing is unclear in its obligations and purpose.

- Section 78.59a-c –Impoundments, Freshwater and centralized
  - The impoundment construction standards (e.g., liner permeability standards, groundwater monitoring network, etc.) are wholly inappropriate for conventional sites. They are more stringent than corresponding DEP regulations for dams and hazardous waste treatment, storage and disposal impoundments. Only a fraction of the freshwater used to fracture unconventional formations is used in Pennsylvania's shallow oil and gas field.

- Section 78.61 - Disposal of drill cuttings
  - The conventional industry currently dusts drill cuttings from above and below the casing seat except where they need to be encapsulated in lined pits to avoid discharges to streams. That practice should be allowed to continue, as proposed. The list of approved solidifiers to be developed under this section should be broad enough to include the solidifiers currently in use and likely to be used in the future, to minimize the delay and cost associated with obtaining individualized approval.

- Section 78.62 – Disposal of residual waste - pits
  - Pits used in the conventional industry for cuttings and flowback are small and do not pose a significant environmental risk. Requiring pit bottoms to be at least 20 inches above seasonal high groundwater is unnecessary and unrealistic, as is the requirement to have a "soil scientist or similarly trained person" certify the isolation distance under section 78.62(a)(9). This is another example of a cumulative unnecessary cost on the conventional industry to achieve an inconsequential environmental benefit.

- Section 78.65 - Site restoration
  - The post construction stormwater controls set forth in this section are excessive. A producing and restored conventional well site footprint is typically no more than 2,000 square feet; it is not at all like a commercial or residential development. Post construction controls frequently are not necessary to ensure that post-construction rate and volume of stormwater is comparable to that of preconstruction.

  - Care must be taken when implementing the statutory language in section 78.65(d) to avoid infringing on legally protected property rights in subsurface oil, gas and minerals. For example, onsite storage of drilling supplies and equipment not needed for production is permissible if the landowner consents in writing. Under Pennsylvania property law (see *Belden & Blake*), the mineral owner has the dominant estate, exercisable with due regard to the surface owner and the mineral owner's reasonable judgment about how to develop his leasehold. Therefore, the mineral owner is entitled at the outset to determine what constitutes reasonable use of the surface. In the conventional setting, development frequently proceeds in a progressive fashion, i.e., an operator will drill a small number of wells on a leasehold, store equipment at a well site itself or at the leasehold in preparation for possible further drilling depending on well production. This may occur more than nine months after the initial well is drilled. Storing equipment at one well site for use in drilling the next well may be well within an operator's property rights for which landowner consent is not required.

  - Section 78.65(g) is presumably drafted to give the surface owner notice of buried drill cuttings on his property. But in so doing the regulation ignores the correlative rights of the mineral owner to advance notice from the surface owner of activities the surface owner plans (such as drilling a water well, erecting a building, etc.) that will reduce the legally permissible areas where an oil or gas well may be placed. If obligations touching on property law principles are imposed at all, they should be imposed fairly on surface and mineral owners.

- Section 78.66 – Reporting and remediating releases
  - The Spill Policy and proposed rule impose obligations for small spills that are excessive and disproportionate to any potential for environmental impact from brines or crude oil spills.

- Sections 78.68a-c - Pipelines and horizontal directional drilling
  - In addition to the comments summarized above regarding horizontal direction drilling, there are several other problems with these proposed sections. For example, gathering lines are improperly defined.

  - Proposed practices for flagging boundaries, maintaining topsoil, and minimizing compaction when backfilling are overly restrictive.