UNSAFE & UNSUSTAINABLE

Experts Review the Center for Sustainable Shale Development's Performance Standards for Shale Gas Development

Prepared for

the Delaware Riverkeeper Network

2014

Unsafe & Unsustainable

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The Delaware Riverkeeper Network champions the rights of our communities to a Delaware River and tributary streams that are free-flowing, clean, healthy, and abundant with life.

The Delaware Riverkeeper Network gives voice, strength and protection to the communities and waterways of the Delaware River. Through independent advocacy, and the use of accurate facts, science and law, DRN works to ensure the rich and healthy future that can only exist with a clean, healthy and free flowing river system.

The Delaware Riverkeeper Network is unique in that it is founded upon the expectation of personal and community responsibility for river protection, as personified by the Delaware Riverkeeper. DRN is the only grassroots advocacy organization that operates watershed-wide and empowers communities with the engaged interaction and information needed to succeed in protecting our River and region now and into the future.

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Acknowledgements

The Delaware Riverkeeper Network would like to acknowledge the ongoing input, review and guidance provided for this report by Dr. Anthony Ingraffea. Dr. Ingraffea is the world's foremost expert/leader seeking truthful dialogue about shale gas extraction. Dr. Ingraffea was an early participant in the assessment and creation of the technologies that are the basis of today's shale gas extraction industry. When Dr. Ingraffea speaks about the limitations, harms and fallacies of shale gas extraction, he does so from a place of extensive, intimate and unrivaled knowledge. The Delaware Riverkeeper Network appreciates the input and guidance Dr. Ingraffea offered throughout the process of compiling these expert reports and his help to ensure that accurate and informed expert dialogue is injected into discussions regarding shale gas extraction and its infrastructure.

We would also like to acknowledge the experts that provided their detailed analyses and reviews of the Center for Sustainable Shale Development's Performance Standards. It is the careful attention of these experts to detail coupled with their proven technical knowledge in their chosen fields of expertise, that makes this report so powerful.

Foreword

A.R. Ingraffea, Ph.D., P.E*

"Unsafe and Unsustainable" is a report written by technical experts. Each presents an insightful critique of relevant elements of the Center for Sustainable Shale Development (CSSD) Performance Standards. Herein I offer the reader some opening observations pertaining to their review.

Mining for gas and oil by drilling for them is not a new industry. The fundamental processes used today to mine the Marcellus— drill, case, cement, stimulate, produce— are over a century old. Much of that century was spent in the "wild west" mode for the industry: little or no regulation by any entity. Even so, the modern state regulatory era began in the 1970's, nearly 50 years ago.

This observation raises these key questions whose answers I leave to the reader to ponder:

1. After many decades of state regulation why does one now need new, better regulations?
2. Why are only 4 of the over 60 operators currently producing shale gas in Pennsylvania partnering with the CSSD?

According to the CSSD, implementation of its performance standards would result in "safe, sustainable shale resource development." Could it be that existing regulations are judged "unsafe" and result in the fear that shale gas development in Pennsylvania might become socio-politically "unsustainable"? If existing regulations in a state that advertises having the toughest regulations in the land are unsafe, where and by how much? Where is the quantitative fault analysis? How does one know that the CSSD standards are fixing anything? And just what is to be sustained? Is it 20 to 30 more years of shale gas development, another 80 to 90 thousands wells, in the face of scientific consensus that most of the undeveloped fossil fuels, including shale gas, must remain undeveloped if we are to contain climate change to hopefully manageable levels?

Safe? Engineers do not use the adjective "safe" to describe an engineering process. Safe literally means nothing can go wrong. And "safer" is, therefore, nonsensical. Rather, engineers acknowledge that there is risk in all processes involving uncertainties, and the best one can do is to attempt to control and limit both the risk and the consequences. Engineers quantify uncertainty by degree, and then can assign reliability factors to processes they can control. There is no sense of such an approach in the CSSD's Performance Standards, even for processes not completely under human control. None of the proposed standards comes with an acknowledgment that it is imperfect, i.e., following it will result in an unsafe action, and none of them quantifies the uncertainty in its outcome or assigns a cost to the probability of failure to meet the standard. Here is an example of what I mean. Rather than this CSSD standard as written:

> Performance Standard No. 7:
>
> Operators shall design and install casing and cement to completely isolate the well and all drilling and produced fluids from surface waters and aquifers, to preserve the geological seal that separates fracture network development from aquifers, and prevent vertical movement of fluids in the annulus.

a modern standard using uncertainty quantification and assigned costs would read:

> "Performance Standard No. 7:
>
> 1. Operators shall design and install casing and cement with the objectives of:
>   a. complete isolation of the well and all drilling and produced fluids from surface waters and aquifers;
>   b. preservation of any possible geological seal that separates the developed fracture/flow network from aquifers; and
>   c. minimization of the probability vertical movement of fluids in all annuli.
>
> but with acknowledgment that a significant number of wells has been proven statistically within the industry to leak fluids into groundwater and the atmosphere (PA DEP and Ingraffea et al., 2014).
>
> 2. Operators shall be responsible for restoration

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> of all surface waters and aquifers impacted by such leakage at costs and for durations determined by an independent arbitration board overseen by Bureau Veritas."

Sustainable? Even if "done right" from a CSSD Standards point-of-view, from a climate change point-of-view sustaining shale gas development is still "wrong". One of the CSSD supporting entities, the Environmental Defense Fund, recently updated its analyses of the net climate benefit from substituting natural gas for its sibling fossil fuels for various purposes, Figure 1.

The key take-away from this figure is that, if the rate of leakage of natural gas—purposeful and accidental—over the lifecycle of natural gas is greater than about 2.7%, there is no short term net climate benefit from any the indicated uses: electricity generation compared to coal, auto travel compared to gasoline, and truck travel compared to diesel. The figure also shows that at leakage rates just slightly higher, say 3%, it would take about 15 years for natural gas to be climate advantageous.

So what is the life-cycle rate of leakage? The EPA has twice revised its *estimate*, based on industry input, for 2009, and currently arrives at 1.8%. However, since 2011 actual *measurements* have been made by independent entities and these are summarized in Table 1.

The results from studies using actual measurements, from regional- to national-scale, show upstream-alone leakage rates much higher than 2.7%, or incomplete life-cycle measurements.

This comparison of leakage rate and its impact is from a purely technical perspective. Very recent

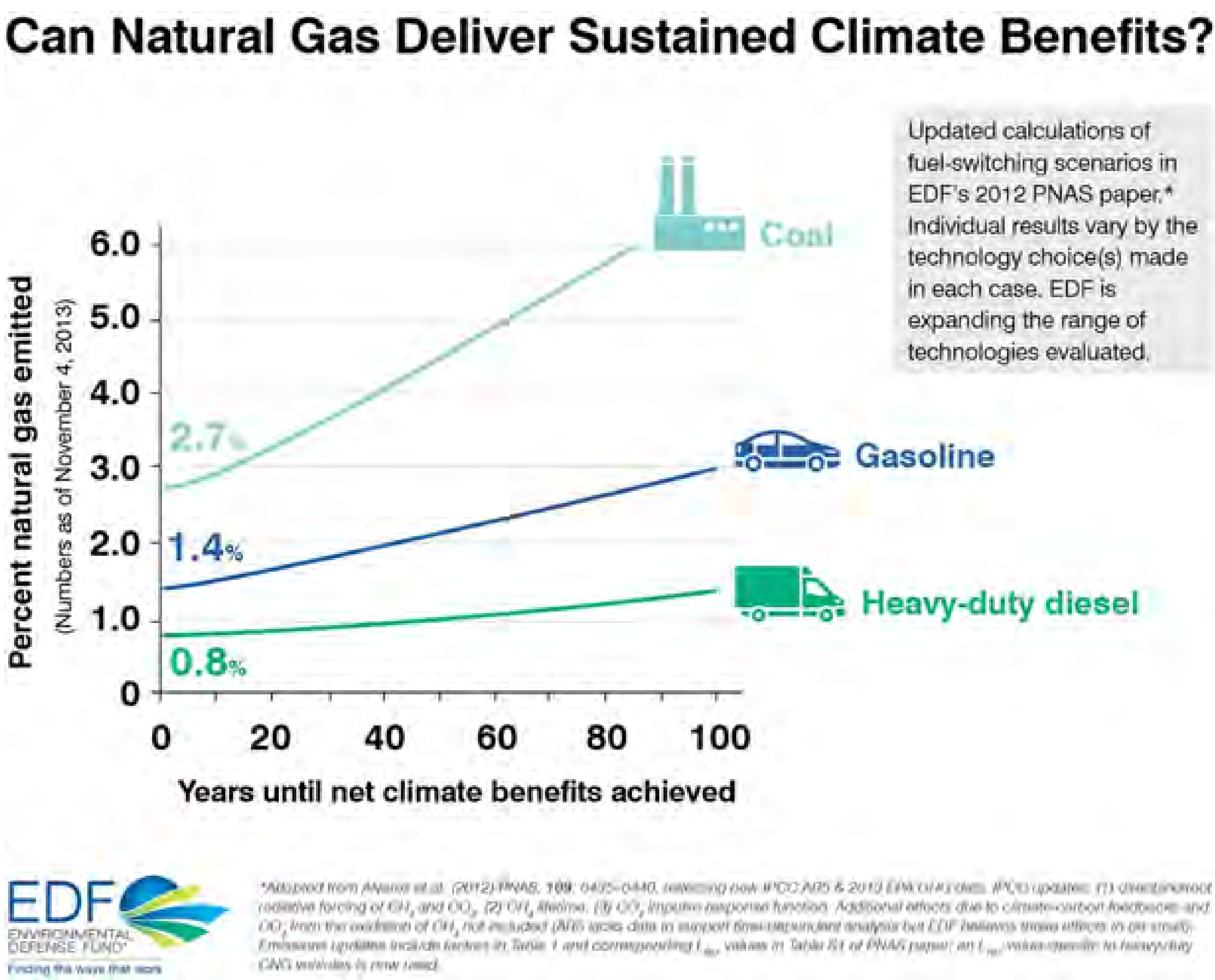

Figure 1. Latest analysis by the Environmental Defense Fund on net climate benefits from substitution of natural gas for sibling fossil fuels for various purposes.

Table 1. Methane emission estimates and measurements. Twice revised EPA *estimates in italics.*

	Upstream (well site)	Downstream (storage, processing, transmission, distribution, etc.)	Total
Hayhoe et al. (2002), conventional	1.3 %	2.5 %	3.8 %
EPA (2010), US average for 2009	*0.16 %*	*0.9 %*	*1.1 %*
Howarth et al. (2011), US average	1.7 %	2.5 %	4.2 %
conventional gas	1.3 %	2.5 %	3.8 %
shale gas	3.3 %	2.5 %	5.8 %
EPA (2011), US average for 2009	*1.8 %*	*0.9 %*	*2.7 %*
conventional gas	*1.6 %*	*0.9 %*	*2.5 %*
shale gas	*3.0 %*	*0.9 %*	*3. 9 %*
Petron et al. (2012), Colorado field	4.0 %	------	-----
EPA (2013), US average for 2009	*0.88 %*	*0.9 %*	*1.8 %*
Karion et al. (2013), Utah field	9.0 %	------	-----
Allen et al. (2013), US average	0.42 %	------	-----
Miller et al. (2013), US average	-----	------	> 3.6 %
Brandt et al. (2014), US average	-----	------	5.4 %
Caulton et al. (2014), PA field	8.2%	------	------
Schneising et al. (2014), 2 US fields	9.6%	------	------

rigorous economic studies (McJeon, 2014; Shearer, 2014) conclude that, from the points-of-view of displacement of coal and renewable energy sources, sustained shale gas development is at best "a wash" in the climate change arena, and could be a step backwards, rather than a bridge forwards.

In summary, the CSSD Performance Standards come at just the wrong time in the history of human energy uses. At exactly the time when we should have been winding down the fossil fuel era because it has led us to a climate precipice, it expands permissiveness for increased development of a fossil fuel, while at the same time delaying the next epoch of energy use.

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Contents

Introduction

The Center for Sustainable Shale Development (CSSD)[1] is a nonprofit partnership among Benedum Foundation, Chevron, Clean Air Task Force, CONSOL Energy, Environmental Defense Fund, EAT Corporation, Group Against Smog and Pollution, Pennsylvania Environmental Council, and Shell. The CSSD organization is focused on shale development in the Appalachian basin and its sole mission is "to support continuous improvement and innovative practices through performance standards and third-party certification."[2] In August 2013, CSSD issued a set of Performance Standards[3] it suggested would, if implemented, achieve "safe, sustainable shale resource development."

The geographic scope of the CSSD performance standards is apparently confined to a portion of the Appalachian basin which includes Pennsylvania, Ohio and West Virginia. According to CSSD materials, the CSSD's intention was to consider the regional geology, topography, population density, infrastructure, surface water, groundwater, and other issues exclusively applicable to this region.

The Appalachian basin is a physiographic province that extends from Maine all the way to Alabama and therefore encompasses an extensive area.[4] The Marcellus shale formation, among others, is pervasive in the CSSD focus area.

The initial CSSD Performance Standards included 15 specific standards that address water resources and air quality. Additionally, CSSD created a certification and verification program based on the standards. According to CSSD, these standards "were developed to drive leading industry practices and to set a bar that goes above and beyond the regulatory requirements..."[5] In actuality, these standards are quite weak in their recommendations ignoring many of the environmental impacts of shale gas extraction and lacking rigorous technical analysis and review. The numerous federal environmental regulatory exemptions in combination with the newness of the industry has created a regulatory bar that is very low and far from adequate to protect natural resources or human health from near-term or long-term damages. Additionally, agencies, experts and the exposed public have already identified environmental and human health and safety issues that these standards fail to address. The Performance Standards do not fulfill the promise of setting a high bar that is protective of the environment or impacted communities. From its inception the CSSD Performance Standards are unclear and flawed. Currently, most of the growth in natural gas production comes from unconventional formations.[6] While the CSSD Performance Standards indicate they are meant to apply to unconventional exploration, development and gathering activities; however, the term "unconventional" is not defined within the report. There is widespread disagreement as to how to define unconventional: some unconventional gas regulations address specific rock formations such as shale while others are based on the methods used such as hydraulic fracturing.[7] And so even the application of the flawed CSSD Performance standards is unclear.

Shale gas reservoirs are one type of unconventional natural gas. The natural gas located in these formations in their in-situ state does not move easily because shale formations are fine-grained, organic-rich rocks with small pores and very low permeability.

1 Information about the CSSD can be found online at https://www.sustainableshale.org/.

2 CSSD, n.d., About The Center for Sustainable Shale Development, https://www.sustainableshale.org/about/.

3 The complete CSSD Performance Standards can be found online at https://www.sustainableshale.org/wp-content/uploads/2014/08/8.19_Performance-Standards-v.-1.2.pdf

4 Coleman, J.L., Milici, R.C., Cook, T.A., Charpentier, R.R., Kirschbaum, Mark, Klett, T.R., Pollastro, R.M., and Schenk, C.J., 2011, Assessment of undiscovered oil and gas resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011: U.S. Geological Survey Fact Sheet 2011–3092, 2 p., available at http://pubs.usgs.gov/fs/2011/3092/.

5 CSSD, n.d., Performance Standards. https://www.sustainableshale.org/performance-standards/

6 Moore, C. W., Zielinska, B., Pétron, G., & Jackson, R. B. (2014). Air impacts of increased natural gas acquisition, processing, and use: A critical review. Environmental science & technology; Ratner, M., & Tiemann, M. (2014). An overview of unconventional oil and natural gas: resources and federal actions, Congressional Research Service Report, January 23, 2014; Vengosh, A., Jackson, R. B., Warner, N., Darrah, T. H., & Kondash, A. (2014). A critical review of the risks to water resources from unconventional shale gas development and hydraulic fracturing in the United States. Environmental science & technology.

7 Pittsburg Post-Gazette, June 7, 2014, Pennsylvania draws a line in the sandstone… Retrieved from: http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-97683/0100-FS-DEP4217.pdf

The inherent characteristics of shale rock make it difficult for gas to flow into a wellbore. Therefore, shale gas is accessed by hydraulic fracturing in which high volumes of water containing chemicals and proppants is pumped into wells at pressures high enough to reopen existing joints and bedding planes and/or to fracture the surrounding rock.

The CSSD's 15 performance standards are split between those that address water and wastewater and those that address air quality issues. The asserted goal of the eight water standards is "zero contamination of fresh groundwater and surface waters." Of the eight water standards, two address wastewater, two address pits and impoundments, and four address groundwater. The eight air standards focus on limitations and reductions in air emissions. More specifically, two of the air standards address flaring, two address engine emissions, one addresses VOC emissions, one addresses air emissions from a list of specific equipment dedicated to unconventional activities, and the last one addresses air emissions from trucks.

In addition to the Performance Standards, CSSD also provides a certification process in which companies can seek certification in "Air and Climate," "Water and Waste," or both. CSSD will first approve auditing companies, and then these auditors will evaluate an applicant's operations compared to the performance standards. Certifications will be issued by CSSD based on the audit reports.

While the voluntary performance standards in conjunction with the certification program are characterized by CSSD as being progressive best practices that achieve "sustainable" development of unconventional shale gas, in reality the recommendations are weak, lack clarity, are generally unenforceable, and cannot, with any level of integrity or earnestness, be said to make the dangerous and damaging practice of unconventional shale gas development safe, sustainable, or environmentally protective.

The CSSD fails to provide the underlying analysis or rationale supporting creation or selection of their proposed standards nor have they proposed the data collection and process for determining their effectiveness (or lack thereof) once implemented. According to the CSSD, the standards will be revised as the result of lessons learned through their implementation but there is no guidance as to how those lessons will be identified, considered, or captured through a revision process.

Performance standards, by definition, should be written in terms of a specific measurement that can be used to appraise performance.[8] The intention is that they are goal-oriented instead of prescriptive in nature. However, the CSSD Performance Standards are vague and contain broad loopholes and ambiguities ignoring many of the impacts to water, air and community resources.

CSSD has not provided any discussion on the rationale for each Performance Standard, the guiding principles used to develop each standard, references to related studies, data analysis and testing information to justify each standard, or any supporting discussion of effectiveness of the proposed standards.

In addition to a lack of rigorous scientific analysis to inform or support the performance standards, CSSD has not provided any technical review or peer-review of these standards, which is typically included as part of a performance standard development process.

All of which leaves us to ask: What is the basis of CSSD's claim that implementation of these performance standards will result in safe and sustainable shale gas development?

Because it is vital that the CSSD Performance Standards be subjected to rigorous and earnest review, a panel of experts was commissioned to review the various sections of the CSSD performance standards and provide an independent analysis of the CSSD recommendations and approach. These expert reviews focused primarily on the application of the Performance Standards to unconventional shale gas development.

The experts chosen represent a range of perspectives and professional specialties:

- **Michele Adams, P.E., LEED AP**, evaluated site and water issues including site disturbance, stormwater management, erosion and sediment control, stream and surface water health, site restoration, and site planning.
- An earth systems scientist with a focus on global climate change research, **Robert W. Howarth, Ph.D.**, evaluated the impact of the

8 i.e., EPA (2013) Draft Guidelines for Product Environmental Performance Standards and Ecolabels for Voluntary Use in Federal Procurement. Retrieved from: http://www.epa.gov/epp/draftGuidelines/

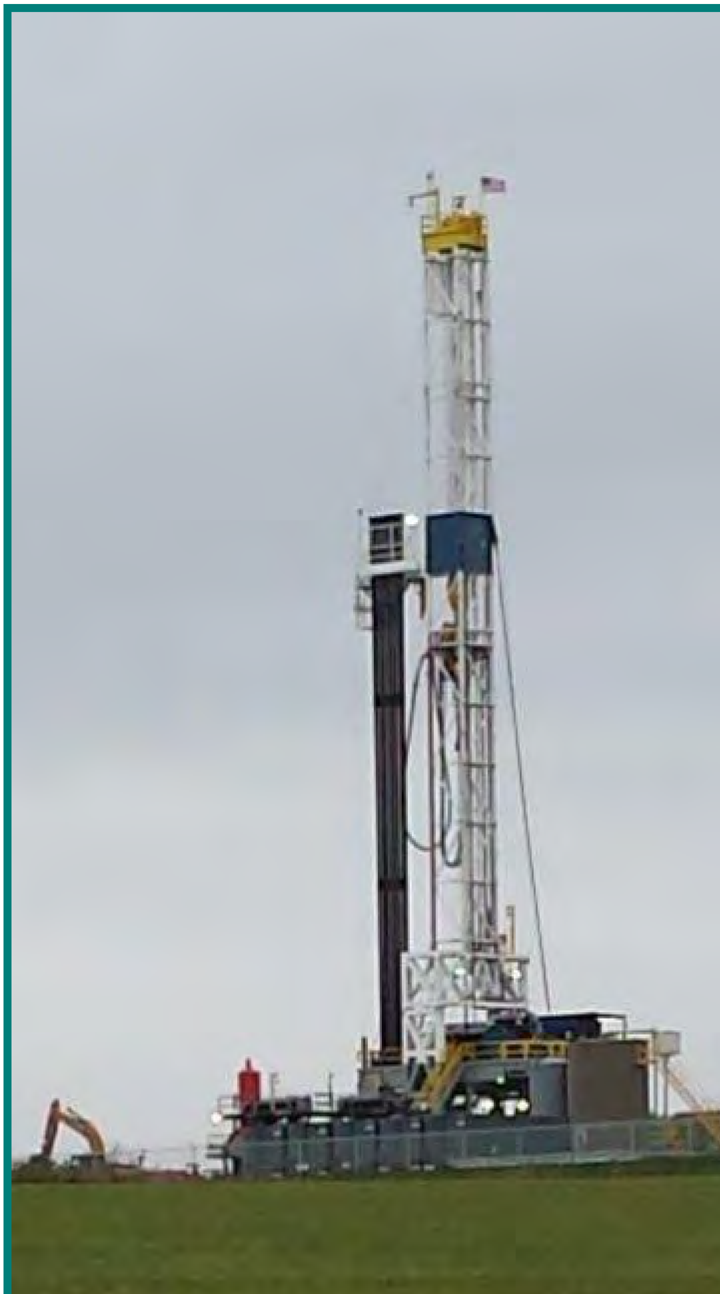
Performance Standards on greenhouse gas emissions.

- **Paul Rubin**, a hydrogeologist with specialized expertise in both surface water and groundwater hydrology, evaluated water and contaminant transport issues.
- Radiation health and safety issues were evaluated by **Marvin Resnikoff, Ph.D.**, and **Carol Ann Sudia** of Radioactive Waste Management Associates.
- **Tom Myers, Ph.D.**, a hydrologist, focused his review on groundwater quality and its monitoring.

These reviews serve to provide an expert evaluation of the Performance Standards that is not driven by the industry or shale gas advocates. These reviews differ according to the experience and background of the individual expert.

Across the board the expert reviews conclude that the Performance Standards fail to achieve the goal of "safe and sustainable" development and lack the scientific rigorousness, objectivity, clarity, and technical requirements necessary to support objective integrity.

In addition to the expert reviews, this report provides a discussion of the better energy path that is available for fueling our region and country.



Executive Summary

CSSD Performance Standards: Site and Water Review

Performance Standards reviewed: Numbers 1, 2, 3, 4, 6, 7, and 8

Michele Adams, P.E., LEED AP

The use of the word "sustainable" in the CSSD name, with a credit-based verification system, implies that shale gas operations verified under this system meet a standard of sustainability (and environmental performance) that is neither defined nor supported by the Performance Standards. This is inaccurate, intentionally misleading, and "greenwashing" at its worst. In addition:

- **A definition of sustainability and meaningful performance metrics are missing from the Performance Standards.**
- **The "verification" system makes no effort to identify and then address the most significant environmental impacts associated with unconventional gas development.**
- **A number of the practices addressed by the verification system (e.g. the use of pits and impoundments for produced and flowback fluids, the use of toxic and carcinogenic additives, potential contact of surface and fresh groundwater with drilling wastes, etc.) are not sustainable and cannot be done in a manner that meets any recognized definition of sustainability.**
- **The standards provide "credit" for practices that the industry is already trending towards as standard practice, such as recycling of flowback and produced waters.**
- **The standards allow for the use of centralized impoundments for flowback and produced water, with significant potential negative impacts for groundwater, surface water, air quality, and wildlife.**
- **The standards recommend monitoring of water sources if contamination is discovered and "linked" to shale gas activity, when focus should be placed on the prevention of contamination and protection of the water sources.**
- **The selected standards completely overlook many significant issues related to:**
  - **Extensive site disturbance**
  - **Lack of land use planning**
  - **Erosion and sedimentation control**
  - **Loss of vegetation, soil compaction, watershed drainage pattern alterations, and impacts to local hydrologic systems (changes in drainage areas, wetlands, shallow interflow, etc.).**
  - **Stormwater management**
  - **Forest fragmentation**
  - **Site restoration criteria, including establishment and maintenance**
  - **Standards for shale development infrastructure, such as pipelines, which from a site disturbance perspective, have a far greater impact than any other component of shale gas activity.**
- **The criteria for emergency response represents a bare minimum and adds little protection beyond what is already addressed by state requirements. This is woefully inadequate for a heavy industry widely dispersed across remote rural areas and state lands.**
- **It is unclear as to how the verification system is and will be applied.**

There is nothing sustainable about the subsurface injection, production, and use of compounds known to be toxic, carcinogenic, and otherwise harmful to human health. The standards fail to examine the known and potential impacts of surface and fresh groundwater contamination from shale gas operations; they fail to examine whether contact can be prevented in both the short and longterm; and they fail to examine the impacts from shale gas extraction with regards to the capacity of future generations to meet their needs. The sustainability of the practice of unconventional shale gas extraction itself should be examined. If it is not possible to prevent surface and fresh groundwater from contact with drilling related fluids and wastes – both in the immediate and the long-term timeframe – then shale gas extraction must be recognized and identified as an industry that can never achieve sustainability.

CSSD Performance Standards: Site and Water Review

Michele Adams, P.E., LEED AP*

These comments on the Proposed Performance Standards from the Center for Sustainable Shale Development (CSSD) pertain primarily to site and water issues, including site disturbance, stormwater management, erosion & sediment control, stream and surface water health, site restoration, and site planning. I assume that the Performance Standards apply to unconventional activities in the Appalachian basin as referenced by the CSSD Performance Standards dated August 19, 2013.

Since the CSSD has developed a Verification Program with a third-party certification process, in the format of other sustainable certification systems (e.g., BREEAM, LEED, SITES, Living Building Challenge, Envision), I have also provided comments related to the certification process for the standards.

I have reviewed both the Performance Standards and the CSSD Guidance for Auditors (August 19, 2013).

<u>Summary of Comments</u>

1. The use of the word "sustainable" in the Center for Sustainable Shale Development's name and the development of a verification system with performance standards imply that shale gas operations verified under this system meet a standard of sustainability (therefore implying environmental performance). This is inaccurate and intentionally misleading. The term "sustainable" is neither defined nor supported by the Performance Standards. Performance metrics, and justification for performance metrics as a measure of sustainability or environmental responsibility, are generally lacking in the Performance Standards. Both overarching sustainability criteria and performance specific definitions and metrics are lacking.

   There are 15 Performance Standards in two categories (Air & Climate and Water & Wastewater). A number of critical issues, such as maintenance of water supply sources, prevention of habitat fragmentation, prevention of surface water impacts, site restoration practices, and other issues, are not addressed nor recognized.

   There is no indication that the verification system has determined the most significant environmental impacts associated with unconventional gas development, or that the standards attempt to address the greatest impacts. Specific performance metrics intended to effect change at a meaningful level are not clearly defined.

   By comparison, early versions of the US Green Building Council LEED Rating System focused (and continue to focus) largely on building energy usage, as that issue was quantified as having a substantial and significant environmental impact, with a potential for quantifiable improvement. There is no similar evaluation or metric in the CSSD standards to identify and target the most significant environmental impacts. The selected standards seem arbitrary.

   Each standard should indicate why that standard is needed and what is to be achieved (intent), and then provide justification as to why specific performance metrics in that standard represents "sustainable shale development." The verification system as a whole must document how it represents "sustainability", and should drive, not respond to, current industry trends. A definition of sustainability is required as a benchmark against which each standard is evaluated (i.e., sustainable practices are those that meet the needs of the current generation, without compromising the ability of future generations to meet their environmental, social, and economic needs). Each standard must indicate the need for that standard, a description of the intent of that standard and how that standard meets the criteria for sustainability. Each standard must define the specific performance metrics required to achieve verification.

   It is my opinion that a number of the practices addressed by the verification system (e.g., the use of pits and impoundments for produced and flowback fluids, the use of toxic and carcinogenic additives, potential contact of surface and fresh groundwater with drilling wastes) are not sustainable and cannot be done in a manner that meets any recognized definition of sustainability. Practices that cannot demonstrate sustainability should be clearly iden-

* Michele Adams, Principal Engineer and founder of Meliora Design, has 25 years of experience in environmentally sensitive site design and sustainable water resources engineering.

tified as such. The Standards should clearly identify all components of shale gas operations that cannot meet defined sustainability criteria.

2. Performance Standard No. 1 requires zero discharge of wastewater to Waters of the Commonwealth – which is a very worthwhile standard - but then negates this standard by indicating that discharges will be permitted when CSSD adopts a standard for treating shale wastewater to allow for safe discharge (with a targeted date of September 1, 2014). The standard for "safe" is undefined (i.e., does safe refer to drinking water standards or antidegradation standards), and the impending target date implies that the technology to achieve a "safe" performance level for discharge is readily available with current technology which is not in fact the case. This is an example of a standard lacking metrics (and therefore not representing a performance standard). Additionally, specific pollutants of concern are not identified.

   The standard does not apply to deep well injection, and no definition of deep well injection or justification as to why deep well injection is safe is provided.

3. Performance Standard No. 2, Item 1, indicates that Operators shall maintain a plan to recycle flowback and produced water for usage in drilling or fracturing "to the maximum extent possible." While recycling of water may be a worthwhile mandate, the standard of "to the maximum extent possible" lacks any metrics or performance criteria, and as such, cannot be considered a "performance standard." Either a performance standard is defined or it is not defined, and Performance Standard No. 2 is completely undefined. "To the maximum extent possible" has no meaning as a metric.

   Performance Standard No. 2, Item 2, attempts to provide an actual performance standard by requiring that a minimum of 90% of flowback and produced water be recycled from wells "in all core operating areas in which an Operator is a net water user." The terms "core operating areas" and "net water users" are undefined, and it is unclear how many wells the 90% would apply to, and how much of the industry generated wastewater would be addressed through recycling. Again, there is a lack of metrics in either the Performance Standard or the anticipated benefit of the Performance Standard in reducing wastewater discharges or achieving sustainability. Furthermore, the industry is already trending toward recycling of flowback and produced waters as a standard practice and therefore, this standard does not drive the advancement of industry practices towards less impact.

4. Performance Standard No. 3 requires the use of a closed-loop system for drilling fluid and flowback water for limiting the use of pits for all fluids other than freshwater by March 20, 2015. The specifics for this requirement are not clearly defined. No site that uses pits for anything other than freshwater should be verified under the CSSD Performance Standards because pits containing flowback and/or produced water have significant potential negative impacts for groundwater, surface water, air quality, and wildlife (as allowed under this standard prior to March 20, 2015).

5. Performance Standard No. 4 allows for impoundments for the storage of fluids other than freshwater, including the use of centralized impoundments for flowback and/or produced water. The use of impoundments for anything but freshwater creates significant potential negative impacts for groundwater, surface water, air quality, and wildlife (as also noted for Performance Standard 3 related to pits). The use of large impoundments for the storage of flowback and/or produced water is an inherently unsustainable practice and therefore has no place in a "sustainable" verification system. Furthermore, the use of impoundments for any fluid (including freshwater) increases site disturbance, increases stormwater impacts, and increases erosion & sedimentation. Increased transportation of materials increases disturbance and the opportunity for spills.

6. Standard No. 6 requires (undefined) monitoring activity for water sources, including additional investigation if contamination is discovered and "linked" to shale gas activity. Corrective action is required if a connection to shale activity is established. Again, there is a lack of specifics and metrics, making this Performance Standard of limited value.

   More importantly, any sustainable approach to protecting water sources should focus first and foremost on prevention and protection of the water source from both a quality and quantity perspective to protect use for future as well as current generations. Undefined "corrective action" in the event that a "positive link" between contamination and shale gas activity is identified does not represent a sustainable practice. Stewardship must be a priority.

7. Performance Standard No. 7 recommends public disclosure of the chemical constituents used in well fluids. It does nothing to suggest that the use of toxic, carcinogenic additives, and additives otherwise harmful to health is inappropriate. There is nothing sustainable about the subsurface injection and production and use of compounds known to be toxic, carcinogenic, and otherwise harmful to human health. The practice that this Performance Standard addresses is inherently unsustainable.

8. Performance Standard No. 8 provides basic recommendations related to emergency response preparation (e.g., standard emergency response best management practices), as well as designing well pads to "minimize the risks that drilling related fluids and wastes come into contact with surface waters and fresh groundwater." These criteria – which fall short in the areas addressed and the recommendations provided – should be basic industry practice for any heavy industry and part of a Pollution Prevention Plan, especially one where the industry is widely dispersed across remote, rural areas. A practice that should be standard industry practice does not qualify as a sustainable performance standard. Additionally, the impacts associated with remote and dispersed heavy industrial practices in rural areas, and the associated site disturbance and management impacts in the context of sustainability and long-term future impacts, should be examined. All components (pipelines, roads, etc.) should be addressed, not just well pads.

   More importantly, however, this standard fails to examine the known and potential impacts of surface and fresh groundwater contamination from shale gas operations, and whether contact can be prevented in both the short term (i.e., pad operation timeframe) and long-term (i.e., post gas extraction activities), and what the impacts will be with regard to the capacity of future generations to meet their needs. The sustainability of the practice of unconventional shale gas extraction itself should be examined. If it is not possible to prevent surface and fresh groundwater from contact with drilling related fluids and wastes – both in the immediate and the long-term timeframe – then this must be recognized and identified as a practice that can never achieve sustainability. If the adverse impacts on current and future generations cannot be prevented, then making this practice slightly "less bad" does not constitute performance of a sustainable metric.

9. The Standards are completely lacking any requirements or criteria related to a number of recognized and significant impacts associated with shale gas activity, including (but not limited to):
   - Extensive site disturbance
   - Lack of land use planning
   - Erosion and sedimentation control
   - Loss of vegetation, soil compaction, watershed drainage pattern alterations, and impacts to local hydrologic systems (changes in drainage areas, wetlands, shallow interflow, etc.).
   - Stormwater management
   - Forest fragmentation
   - Site restoration criteria, including establishment and maintenance
   - The lack of standards for components of shale development infrastructure, such as pipelines, which from a site disturbance perspective, have a far greater impact than any other component of shale gas activity.

   As part of any verification system administered by a "sustainable" organization, these and other issues should be addressed from a "first do no harm" perspective. Any verification system represented as sustainable must identify and address the factors that are likely to have the greatest adverse impacts. Recommendations must truly achieve sustainability and not simply be "less bad" if they are to have any credibility. Of course, with shale gas development, the very real question that needs to be addressed is: is there any way to make unconventional shale gas development safe and sustainable?

Detailed Discussion

1. **The use of the word "sustainable" in the CSSD name and the development of a verification system implies that shale gas operations verified under this system meet a standard of sustainability and therefore environmental perfor-**

mance and ecosystem resilience for future generations, and yet the term is neither defined nor supported by the Standards. This is incorrect and misleading.

By creating a verification system as a Center for "sustainable" development, the Center is representing to the industry and especially to the general public that a project certified under this system is implicitly sustainable. And yet, no definition of the term "sustainable" can be located within the CSSD web page or supporting documents. Instead, the CSSD web page states that the intent of the Performance Standards is to "*set a bar that goes above and beyond the regulatory requirements established by Appalachian states (specifically, Pennsylvania, Ohio and West Virginia) and the federal government.*"

Simply exceeding current regulatory requirements does not constitute sustainability, especially since the industry is exempt from so many federal environmental requirements, either directly or under the 2005 Energy Policy Act. These exemptions include components of the Safe Drinking Water Act (SDWA); the Clean Water Act (CWA); components of the Clean Air Act; the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); the Resource Conservation and Recovery Act (RCRA); and the Emergency Planning and Community Right to Know Act. The burden therefore falls to state regulations (and regulators) to address the many voids created by federal exemptions, to the degree they can or choose to do so. This lack of federal regulation (that states normally rely upon), combined with the newness of the industry and the heavy industrial nature of unconventional gas operations sets a current regulatory bar that is very low, and far from adequate to protect water resources and ecosystems from long-term damages that they may not recover from. Simply exceeding current regulations does not constitute sustainability.

The current Pennsylvania state regulations do not fill the void created by the federal exemptions, nor do they adequately protect resources. Even so, current state regulations identify many environmental issues (stormwater, erosion, site disturbance, riparian buffers, restoration, etc.) that the Standards fail to include. Several of the issues related to site disturbance that the Standards fail to address are discussed later in this review. Simply setting a criterion for the Standards to "set a bar that goes above and beyond the regulatory requirements" is in no way correlated with sustainability, and it can be argued that the Standards are far less protective in many ways than even current regulations. Again, verification under the Standards falsely conveys to the public a sense of environmental performance that does not exist.

This misrepresentation is not uncommon in the unconventional gas industry. A commonly cited diagram on the Energy From Shale web page (Figure 1) implies to the uninformed viewer that stormwater from an unconventional gas well pad requires a stormwater NPDES permit under the Clean Water Act, but in fact this is only true if the stormwater comes into contact with fracking materials AND contributes to a water quality violation. Generally, stormwater NPDES permits are NOT required for unconventional gas well pads. Only flowback from the well is regulated by the NPDES program. This is very confusing to the public, and the industry diagram fosters this confusion. The Standards and proposed verification system are similar in nature regarding misleading implications.

Most commonly recognized environmental performance rating systems (e.g., BREEAM, LEED, Living Building, SITES, Envision) have been developed to raise public awareness of critical issues, to identify and quantify issues of significant environmental and human health concern, and to lead the industry toward a measurably higher standard of environmental performance until sustainability is achieved. Clear definitions and metrics are a key component of these rating or verification systems. These rating systems identify and focus on issues with the greatest environmental impact.

Public expectation is that a rating system put forward by an organization with "sustainable" in its name is based on very high performance standards. Without specific performance metrics identified to achieve quantifiable improvements, the Performance Standards represent what is commonly referred to as "greenwashing." A 2009 Scientific American article stated that "*Greenwashing is what happens when a hopeful public eager to behave responsibly about the environment is presented with 'evidence' that makes an industry or a politician seem friendly to the environment when, in fact, the*

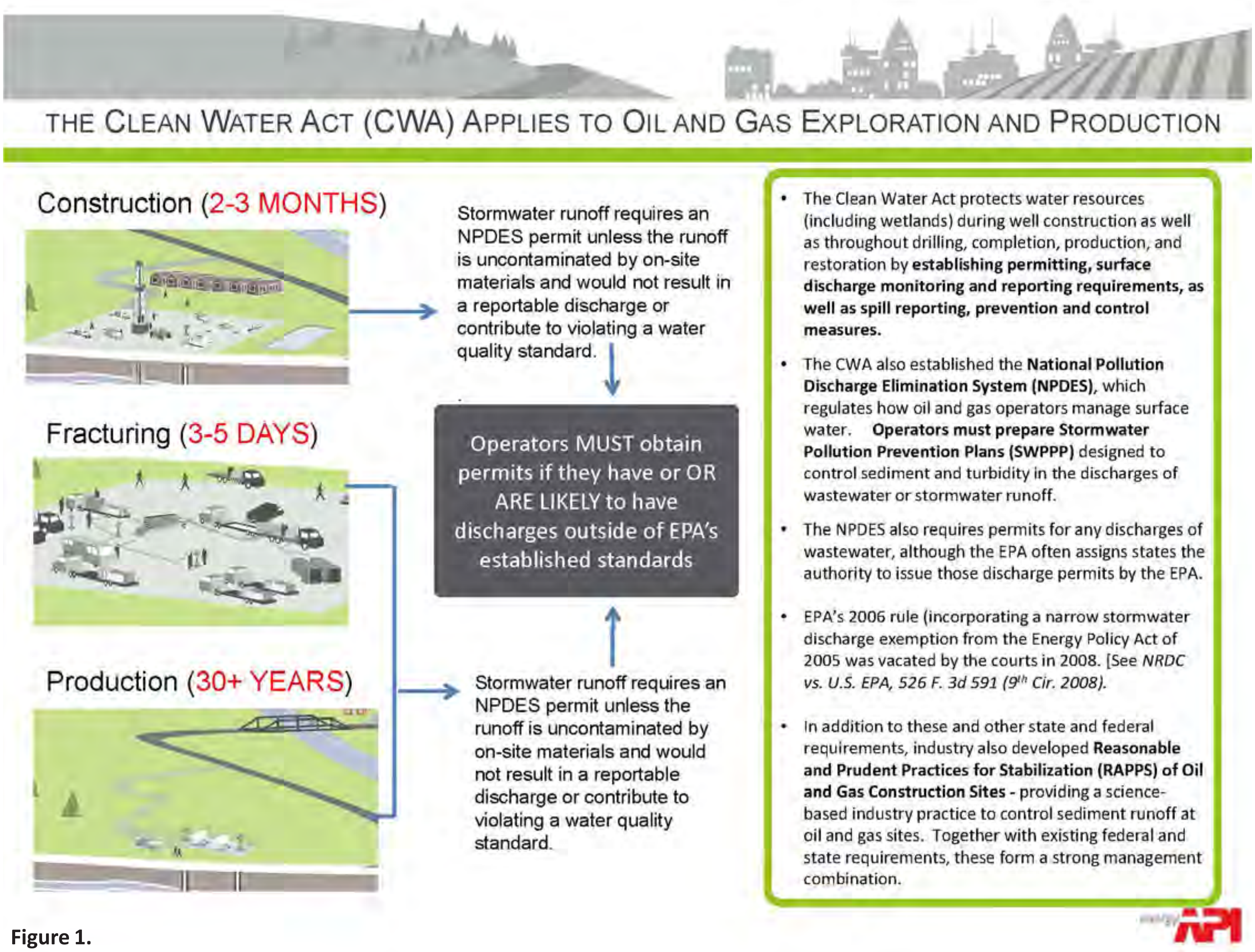


Figure 1.

industry or the politician is not as wholly amicable as it or he might be." (Hoffman, Jane). The current CSSD Performance Standards and verification represent an example of greenwashing, and require significant expansion and improvement in order to represent a true verification system for an organization self-defined as sustainable.

There are 15 Performance Standards in two categories (Air & Climate and Water & Wastewater). There is no indication that the verification system has evaluated and quantified the most significant environmental impacts associated with unconventional gas development, and developed standards in response to these recognized or anticipated impacts, with specific performance metrics intended to effect change at a meaningful level. As an example, early versions of the US Green Building Council LEED Rating System focused (and continue to focus) largely on building energy usage, as that issue was quantified as having a substantial and significant environmental impact, with a potential for quantifiable improvement. There is no similar evaluation or metric in the CSSD standards. The selected areas of focus for the standards seem arbitrary.

Each standard should indicate why that standard is needed and what is to be achieved (intent), and then provide justification as to why specific performance metrics in that standard represents "sustainable shale development." The verification system as a whole must document how it represents "sustainability." Each standard must indicate the need for that standard, a description of the intent of that standard, and the specific performance metrics required to achieve verification.

It is also unclear as to how the verification system is and will be applied. The web page FAQ indicates that there are two major categories (Air & Climate and Water & Wastewater), and that projects can currently be certified in one or the other, but within two years must be certified in both. It is implied that all credits must be achieved for certification, although this is not explicit.

2. **Performance Standard No. 1 requires zero discharge of wastewater (drilling, flowback, and production waters) to Waters of the Commonwealth, but negates this standard by indicating that discharges will be permitted when CSSD adopts a standard for treating shale wastewater to allow for safe discharge (with a targeted date of September 1, 2014). The standard for "safe" is undefined, and the impending target date implies that the technology to achieve a "safe" performance level for discharge is readily available with current technology when that is in fact not the case**.

   Shale gas operation wastewater includes high levels of total dissolved solids (TDS), fracturing fluid additives, metals, and naturally occurring radioactive materials. The Standard does not distinguish between types of shale gas wastewater (i.e., drilling fluids with high metals concentrations, flowback water with higher levels of chemical additives, or production water that has been in contact with the shale formation for longer periods of time), nor does the standard discuss the types of pollutants, their concentrations, and the specific challenges associated with treatment for a safe discharge. Specifically, high levels of salinity or TDS are not readily treated at wastewater treatment plants and can have a negative effect on biological treatment systems, effectively reducing the performance of a wastewater treatment plant for all wastewater it receives. For example, the March 2014 Auburn, New York POTW Headworks Analysis Report concluded that no gas drilling wastewater should be accepted at the plant due to excess chloride loading (City of Auburn, 2014). Metals are also problematic for biological wastewater treatment systems, adversely impacting system performance and passing through the treatment process to the discharge effluent. Conventional municipal wastewater treatment plants based on biological treatment processes are generally not equipped to treat gas extraction wastewater with high levels of TDS or metals.

   The standard does not apply to deep well injection, however, no definition of deep well injection, or justification as to why deep well injection is safe to Waters of the Commonwealth, is provided.

   Performance Standard No. 1 does not provide any meaningful performance criteria:

   - The term "safe discharge" is not clearly defined with a metric that can be verified. The basis for the performance metric being "safe" is not documented, and guidance regarding supporting testing requirements for all anticipated pollutants at specified frequencies is not provided. The term "safe discharge" requires substantial definition and associated documentation requirements.
   - All specific pollutants of concern, and anticipated concentrations, must be identified in any criteria for safe discharge, and consideration must be provided as to the capacity of current technology to achieve treatment to the levels defined as safe. The technology must exist to provide treatment. Furthermore, criteria for safe discharge should be established by toxicologists and medical experts, not on very limited MCL standards that did not contemplate subsurface discharge of and public exposure to hundreds of toxic chemicals when they were promulgated.
   - In developing Performance Standard No. 1 and a standard for treating wastewater to allow for safe discharge, the CSSD must consider the anticipated volumes of wastewater and the capacity of existing treatment facilities and receiving waters to meet the industry needs (as well as all other wastewater treatment needs). The infrastructure must not be overwhelmed. The CSSD standard for treating shale wastewater must demonstrate that the discharge is in fact safe for all pollutants of concern and can be achieved with existing or proposed infrastructure (the plants must not only have the technology, but also the capacity to handle the wastewater, and the same must be true of receiving streams).
   - Criteria for deep well injection and documentation demonstrating that deep well injection is a "safe" disposal method are required to justify the exemption for disposal via deep well injection.
   - The life cycle costs and environmental impacts of generating, transporting, treating, and

discharging gas operation wastewater and residual wastes must be considered and criteria developed to address these life cycle costs so the treatment of gas operation wastewater is "sustainable."

3. **Performance Standard No. 2, Item 1, indicates that Operators shall maintain a plan to recycle flowback and produced water for usage in drilling or fracturing "to the maximum extent possible."** The standard of "to the maximum extent possible" lacks any metrics or performance criteria, and as such, cannot be considered a "performance standard." Performance Standard No. 2 is completely undefined. "To the maximum extent possible" has no meaning as a metric. Terms such as "maximum extent possible" must be eliminated and replaced with quantifiable metrics.

   Performance Standard No. 2, Item 2, attempts to provide an actual performance standard by requiring that a minimum of 90% of flowback and produced water be recycled from wells "in all core operating areas in which an Operator is a net water user." But the terms "core operating areas" and "net water users" are undefined, and could create a loophole or ambiguity regarding this performance standard.

   It is unclear in the CSSD documents how many wells they anticipate the 90% recycling criteria would likely apply to, and how much of the industry generated wastewater would be addressed through recycling. Again, there is a lack of metrics in either the Performance Standard or the anticipated benefit of the Performance Standard in cumulatively reducing wastewater discharges or achieving sustainability. In other words, is this standard moving the industry toward greater sustainability?

   The Shale Gas Roundtable, in its August 2013 Report, noted "*more than three quarters of shale gas wastewater in Pennsylvania is currently being used for hydraulic fracturing of additional wells through on-site and centralized treatment and recycling systems. In the second half of 2010, 65 percent of waste fluid went to industrial treatment facilities and about 25 percent of wastewater was reused. From July through December 2012, operators used on-site recycling technology or centralized treatment facilities to reuse 453 million gallons of wastewater or 84.5 percent of the total produced during that time period. Some companies are able to recycle more than 90 percent of their wastewater.*" Given that wastewater recycling is currently occurring in Pennsylvania at rapidly increased rates, and at or near 90% on some sites, there is nothing inherently forward-thinking in the proposed CSSD metric for Performance Standard No. 2. This requirement is essentially a "give away" providing no improvement in performance standards and the sustainability of resources beyond what is currently occurring as an industry trend.

4. **Performance Standard No. 3 requires the use of a closed-loop system (instead of pits) by March 20, 2015 for all fluids other than freshwater at the well**. The specifics for this performance are not clearly defined. By allowing the use of pits for anything other than freshwater prior to March 2015, the CSSD Performance Standards fall short of protecting water quality. Additionally, the requirements do not address all pits, just pits "at the well pad." However, by eliminating the use of pits at the well pad by March 20, 2015 (for anything other than freshwater) the Standards do set a higher requirement than state regulations in Pennsylvania.

5. **Performance Standard No. 4 allows for impoundments for the storage of fluids other than freshwater, including the use of centralized impoundments for flowback and/or produced water. The use of impoundments for any fluid (including freshwater) increases site disturbance, increases stormwater impacts, increases erosion & sedimentation, and increases contaminant migration potential coincident with leaks and liner failure. The transportation of fluids to and from impoundments provides opportunities for spills, increases land disturbance, and uses resources. This is an inherently unsustainable practice**. **Additionally, the use of impoundments for anything but freshwater creates significant potential negative impacts for groundwater, surface water, air quality, and wildlife.**

   Centralized impoundments for the storage of flowback and/or produced water can contaminate groundwater and surface water, cause air quality problems, and pose a threat to wildlife. Centralized impoundments located close to homes can expose nearby residents to toxic emissions. The construction of impoundments significantly increases the site disturbance footprint, increasing stormwater impacts, increasing erosion and sediment potential, and potentially increasing the disturbance of natural areas such as forest. Waste collected and transported by pipeline or truck to a larger open impoundment at a centralized location away from the well site results in additional transfer steps that provide unnecessary opportunities for pollution releases.

Performance Standard No. 4 should not be allowed under a verification system represented by a "sustainable" organization.

Additionally, the Performance Standards do not include criteria for freshwater impoundments related to location, maximum size, construction requirements, security, and site restoration. The volume of freshwater required by unconventional shale gas operations, and the storage requirements for water, result in impoundments that have significant site disturbance footprints. The Performance Standards do not address these issues.

6. **Standard No. 6 requires (undefined) monitoring activity for water sources, including surface water sources within a 2,500 foot radius of a wellhead. Additional investigation is required if contamination is discovered and "linked" to the shale gas activity. Corrective action is required if a connection to shale activity is established.** Again, there is a lack of specifics and metrics to give this standard any value.

   Contamination of a surface water source may occur due to activity at a wellhead, but may also occur due to activity related to fluid storage and transportation that is not in proximity to a wellhead. Surface source waters can also be adversely affected by other industry related activities, such as stormwater and erosion and sediment issues related to construction, high gravel road usage, etc. Requiring monitoring only within 2,500 feet of a wellhead (and only for the first year) effectively ignores other potential shale gas development sources of contamination to source waters. Comprehensive long-term water quality monitoring of surface waters, including both chemical and biological monitoring at locations downstream of all gas development activities, is required to assure that water quality is maintained.

   Any sustainable approach to water sources should focus first and foremost on prevention and protection of the water source from both a quality and quantity perspective, to protect use for future generations. Undefined monitoring, and undefined "corrective action" in the event that a "positive link" between contamination and shale gas activity does not represent a sustainable practice. A failure to identify all water sources potentially impacted by all unconventional shale gas activity, and to identify potential sources and pollutants does not represent a sustainable practice.

   This standard does not include:

   - Requirements to identify all potential pathways and contaminants related to all gas operations that could impact surface source waters and groundwater, including activities related to transportation of materials.
   - Identification of all specific pollutants of concern.
   - A proactive program that identifies practices to prevent any potential source water contamination.
   - Specific monitoring requirements dependent on the source and nature of potential pollutants, including sampling standards, testing criteria, and reporting standards.
   - Specific minimum requirements for a corrective action plan.
   - A provision against re-stimulating of a well until all corrective action plan requirements have been implemented.

7. **The public disclosure of the chemical constituents used in well fluids is an important and necessary requirement. Performance Standard No. 7 does not require (but instead simply recommends) the use of environmentally neutral additives**.

   In the simplest of terms, the intentional use and injection of chemicals that are known to be toxic, carcinogenic, or in any way harmful to human health flies in the face of sustainability.

8. **Performance Standard No. 8 recommends designing well pads to "minimize the risks that drilling related fluids and wastes come into contact with surface waters and fresh groundwater." This Performance Standard also requires that operators develop an emergency response**

plan and "work with the local governing body", etc. This does not represent a "standard" for sustainability. These requirements should be basic industry practice for any heavy industry.

Additionally, as basic industry practice for any heavy industry, chemical handling, access roads, storage areas, and pipelines – as well as well pads – must be designed to prevent the contact of surface or groundwater to drilling related fluids. All personnel should be trained in practices to prevent any possibility that surface or fresh groundwaters will come into contact with any industry related material (not just drilling related fluids and wastes) that could adversely affect water quality or human health. Operators should not only be responsible for providing the necessary equipment and training for response to an emergency at a well, but also for emergencies occurring along the supporting infrastructure of gathering lines, pipelines, and improved roads. Design standards and practices should emphasize prevention, not simply minimizing risks. These practices should be part of standard industry practice, and do not represent a Performance Standard towards sustainability.

More importantly, however, this standard fails to examine the known and potential impacts of surface and fresh groundwater contamination, as well as the impacts associated with remote and dispersed industrial practices in rural areas, and the associated site disturbance and management impacts in the context of sustainability and long-term future impacts. If it is not possible to prevent surface and fresh groundwater from contact with drilling related fluids and wastes – both in the immediate and the long-term timeframe – then this must be recognized and identified as a practice that can never achieve sustainability. If the adverse impacts on current and future generations cannot be prevented, and making this practice slightly "less bad" does not constitute performance of a sustainability metric. This cannot be recognized as a sustainable practice.

9. **The Performance Standards do not address a number of critical resource issues whose sustainability is or may be impacted by unconventional shale gas development (e.g., impacts on water supply, habitat fragmentation), and the standards seem arbitrary in the selection of issues for which standards are developed**.

The performance standards include:

- Two standards for wastewater (Nos. 1 and 2)
- Two standards for pits and centralized impoundments (Nos. 3 and 4)
- Two standards related to groundwater and source water monitoring (groundwater and surface water - Nos. 5 and 6)
- One standard related to well construction and chemicals used (No. 7)
- One standard related to spills and emergency response practices (No. 8)
- Seven standards related to air quality (Nos. 9 to 15).

But there are no standards that address the critical issues of:

- Capacity of water sources, and the potential impact on both local and regional water surface and groundwater supply sources due to the consumptive nature of unconventional shale gas development. This issue is not examined to determine the cumulative impacts on water supply sources with the anticipated consumptive needs of the industry, or to set performance standards to define or achieve sustainability.
- There is no consideration of the ecological impacts from water consumption impacts at the local level (including impacts on headwater streams and wetlands) or at the larger watershed level.
- Habitat loss and fragmentation, including forest fragmentation and the capacity of systems to recover, is not addressed.
- Extensive site disturbance and practices to reduce site disturbance are not addressed.
- Lack of land use planning, including access road locations and lengths. No recommendations for planning to reduce impacts are provided.
- Erosion and sedimentation control, which is the primary issue related to many of the documented water quality violations, is not addressed.
- Loss of vegetation, soil compaction, watershed drainage pattern alterations, and impacts

to local hydrologic systems are not addressed.

- Stormwater management is not addressed.
- Site restoration, including establishment and maintenance criteria, is not addressed.
- The control of invasive species and consideration of their impacts is not addressed.
- Methane releases from wells, stray gas migration, life cycle costs related to materials, and carbon footprint are not addressed.
- The performance standards do not address public health and safety.

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Executive Summary

CSSD Performance Standards: Impact on Greenhouse Gas Emissions

Performance Standards reviewed: Numbers 1, 2, 3, 4, 5, 6, 7, 9, 10, 13, and 14

Robert W. Howarth, Ph.D.

While superficially appearing to be stringent, the draft CSSD standards are in fact extremely vague and riddled with giant loopholes. Rarely do they push beyond current industry practices, even though current industry practices clearly lead to severe pollution and release of methane, a powerful greenhouse gas. On many important issues, the draft standards are silent. For instance, the standards make no mention of possible methane emissions (and provide not even first-step guidance towards regulations for limiting these emissions) from under-balanced drilling, from gathering pipelines, or from de-commissioned wells, all of which recent research has indicated these may be major sources of methane emissions from shale gas operations. Other failings of the standards include:

- The standards are ambiguous as to whether they apply to all unconventional energy (including shale oil), or just to unconventional gas.
- Despite increasing evidence that deep-well injection of frack-return wastes causes earthquakes, the standards explicitly state they do not apply to such injection.
- The standards urge recycling of frack-return wastes to "the maximum extent possible," but do not provide any guidance as to what is possible. They call for recycling of at least 90% of these wastes, but never define "recycling" (a term which to some includes release of "treated" waste streams back to surface waters).
- The standards on frack-return wastes apply only to "core operating areas" without defining what constitutes a core operating area, and only if an operator is a "net water user," without defining what a net water user is.
- A casual read of the standards could give the impression that storage of frack-return wastes is not allowed in open pits, but in fact the limitation applies only for smaller pits at well-pad sites. The standards specifically allow "centralized impoundments" for storage of such wastes. A centralized impoundment is a large open pit, or in the words of the standards, an "in-ground impression constructed off the well site which is used to store and aggregate flowback water." "Water" is a misnomer for this toxic mix of frack-return wastes.
- The standards state that before frack-wastes are stored in an open pit, "free hydrocarbons" should be removed, but they do not define "free hydrocarbons." They call for measures to "reasonably prevent hazards to wildlife" without defining what is reasonable and without any guidance as to how this should be done. And they state "total hydrocarbons should be substantially removed" without defining what is meant by "substantial."
- The standards call for an investigation of "geological vulnerabilities" before drilling operations commence, but do not define these vulnerabilities beyond earthquake faults. There is no explicit consideration of pockets of shallow gas or gas in coal mines or coal seams.
- The standards prohibit the use of diesel fuel as an additive for fracking, but they are silent as to the use of other fuels and petroleum products that are very similar in their chemical composition and contain similar amounts of toxic and carcinogenic hydrocarbons such as benzene and toluene. These other products include kerosene, petroleum distillates, petroleum spirits, jet A aviation fuel, and #2 fuel oil.
- The venting of methane at the time of flow-back after well completion is a major source of greenhouse gas emissions from shale-gas wells. The standards address this venting, but the proposed regulations are no more stringent than current law and are full of loopholes. For instance, "pipeline quality" gas is required to be captured and sold to market, but this applies only to wells in established gas-producing areas and not to "exploratory wells" or to "extension wells" (terms which are very vague in the context of shale gas, and are not defined by the standards). Non "pipeline-quality" gas of insufficient quality to be put directly into a pipeline without processing is exempted, and could be flared instead. Some venting of unburned methane would be allowed, since a footnote to the standard states that "for purposes of this standard, venting does not include the de minimis fugitive emissions from gas busters," without defining "de minimis." Other exceptions are made for gases of "low flammability" or for "safety reasons," yet more terms that are not defined.
- The standards call for regular inspections for methane leakage, but only using the common industry practices of the past several decades, which are inherently insensitive. The standards do not even note that far more effective and more modern technologies for inspecting for and measuring methane leaks are now available.

CSSD Performance Standards: Impact on Greenhouse Gas Emissions

Robert W. Howarth, Ph.D.*

I have carefully read the Performance Standards from the Center for Sustainable Shale Development (CSSD) dated August 19, 2013 and have many comments and criticisms. In addition to the specific comments on particular Standards below, I offer these general comments.

First, the CSSD Standards are ambiguous as to whether they apply to all unconventional energy (including shale oil, for instance), or just to unconventional gas.

Second, the standards are silent on the practice of under-balanced drilling, which may be a major source of methane emissions in some areas. The normal process of pressurized drilling can pose a risk of damaging pre-existing structure such as coal mines and other oil and gas wells, and so under-balanced drilling (which does not pressurize the well) is often used instead in areas of prior fossil-fuel extraction, which includes much of the Marcellus shale play. Caulton et al. (2014) observed very high rates of methane emission from some shale-gas wells in southwestern Pennsylvania in such an area as they were being drilled (before the wells reached the shale formation, and before being hydraulically fractured); under-balanced drilling is one possible explanation for this (Howarth 2014).

Third, the standards are silent on leaks and other emissions from gathering lines, the pipelines that connect gas wells to higher pressure transmission pipelines. To date, there are no published data on methane emissions from such lines, but these gathering pipelines may be one of the reasons that top-down measurements of methane emissions consistently show higher rates than estimated from the US EPA bottom-up estimates, which do not consider gathering pipelines (Pétron et al. 2012; Karion et al. 2013; Miller et al. 2013; Brandt et al. 2014; Caulton et al. 2014; Howarth 2014).

Fourth, the standards are silent on leaks from decommissioned wells. Wells become re-pressurized after they are plugged and can leak significant quantities of methane to the atmosphere for decades into the future (Kang 2014; Duesalt et al. 2014). As with gathering pipelines, this has received insufficient study, but may be one of the reasons that top-down measurements of methane emissions are consistently showing higher rates than estimated from the US EPA bottom-up estimates (Pétron et al. 2012; Karion et al. 2013; Miller et al. 2013; Brandt et al. 2014; Caulton et al. 2014).

Specific Comments:

Performance Standard #1: The standard calls for "zero discharge" until a standard is adopted for "safe discharge." No definition is given for "safe discharge," and many of the materials in flowback and coproduced waters are toxic, mutagenic, carcinogenic, and/or radioactive and cannot be safely discharged to surface or groundwaters at any level. Further, some nontoxic materials such as bromides when discharged to surface waters, while not that harmful in the receiving waters themselves, when drawn into a municipal drinking water supply and treated with chlorination can produce very dangerous brominated organic compounds.

The standard explicitly states that it does not apply to deep well injection of waste, nor is there any other standard on such disposal. The evidence is strong that such disposal can lead to earthquakes (Ellsworth 2013).

Performance Standard #2: This standard urges the recycling of flowback and produced water, but is terribly vague. Clause 1 calls for "the maximum extent possible," without guidance as to what is possible. Clause 2 calls for a minimum of 90% of flowback and produced water to be recycled, yet the standard does not define what is meant by recycling. One interpretation of recycling is that the flowback fluids are used entirely for further hydraulic fracturing, but another interpretation is that the fluids are released back into the environment and "recycled" as part of the water cycle; this latter definition could result in significant water pollution, if the "recycled" fluids are not adequately treated before release (and it is not clear that they can be adequately treated). Further, the standard applies only to "core operating areas" with-

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out defining what constitutes a core operating area, and only if an operator is a "net water user," without defining what a net water user is.

Performance Standard #3: Clause 2 explicitly allows the use of oil-containing drilling fluids (by stating they should be used only in a closed loop system). Any oils or oil-related products that contain benzene, toluene, and other such toxic and carcinogenic hydrocarbons pose a significant risk because of the risk of contaminating groundwater when well casings or cement fail.

Clause 3 prohibits the use of "open pits," as defined in footnote #2, but this applies only to pits at the well pad, since the footnote defines "open pits" in this very limited way. An "in-ground impression constructed off the well site which is used to store and aggregate flowback water" is not defined as a pit by the CSSD standards, but rather as a "centralized impoundment," and yet any common language use of pit would not make this distinction, which seems quite misleading. These "centralized impoundments" have all of the same environmental issues as do open pits that are physically on the well pad, with the only distinction being that they are likely larger since they serve multiples pads. Yet these centralized impounds are allowed by the CSSD standards (see comments on performance standard #4). Further, the prohibition on open pits at the well pad applies only to natural gas wells; oil wells or other liquid hydrocarbon wells are not prohibited by this standard. Any open pit, whether on a gas well pad or an oil well pad, and whether defined as a central impoundment or not, poses risks of leaks to the groundwater, run-over during flood events, volatilization of toxic and carcinogenic compounds to the atmosphere, and exposure to wildlife and birds that enter the pit. Fencing, if adequate, can reduce exposure to some wildlife, but the CSSD standards are silent on this. And birds are at risk from any pit, fenced or not.

Performance Standard #4: Clause 1 explicitly allows for open pits as long as they are not at the well-pad site, and are defined as "centralized impoundments" that serve multiple pads. The standard is incredibly vague, stating that "free hydrocarbons" should be removed without defining what free hydrocarbons are; calling for measures to "reasonably prevent hazards to wildlife" without defining what is reasonable; and stating that "total hydrocarbons should be substantially removed" without defining what is substantial. Further, the clause calls for double lining these centralized pits and using leak detection equipment, but providing no guidance as to what materials and in what thicknesses would be considered acceptable for the lining and no guidance on how leaks should be detected in terms of types of equipment or types or frequency of measurement. Virtually all containment structures are prone to some leakage, yet the CSSD standards are silent on how an "acceptable" level of leakage would be determined or what level of leakage would demand remediation (or how remediation would be conducted).

Performance Standard #5: The standard calls for an investigation of other active or abandoned wellbores and other "geological vulnerabilities," but does not define these vulnerabilities beyond "faults." With regard to methane emissions to the atmosphere, a large suspected pathway is the release during well drilling as pockets of shallow gas or gas in coal mines or coal seams are encountered (Caulton et al. 2014). This pathway of methane emissions has not been previously recognized by the US EPA, nor publicly acknowledged by any industry source. The performance standard is much too narrowly constrained in its focus just on geological faults and abandoned wells, and not providing guidance on other risks.

Performance Standard #6: The standard calls for monitoring of groundwater, but does not specify who has access to the monitoring data or how such monitoring data could or would be used to reduce groundwater pollution. Further, clause 3 states that if "monitoring establishes a possible link" to groundwater contamination, the operator should "develop and implement an investigative plan." The standard does not indicate how data would be analyzed in order to determine such a link, or by whom, or what specifically should be done to develop and implement the investigative plan. Once a "positive link is established," through some non-specified process, the CSSD standards do not describe the nature of a "corrective action plan." There are few if any positive examples where groundwater has been successfully cleaned up from pollution from oil and gas operations.

Performance Standard #7: Clause 2 prohibits the use of diesel fuel. However, this standard in particular and the CSSD standards in general are silent about the use of other fuels and petroleum products that are very similar in their chemical composition to diesel and contain similar amounts of dangerous hydrocarbons such as benzene and toluene. Such oil products include petroleum distillates, petroleum spirits, kerosene, jet A aviation fuel, and #2 fuel oil. Use of any of these poses threats that are very similar to the use of diesel fuel.

Clause 3 states that "chemical ingredients should be disclosed in a manner that does not link them to their respective chemical additive products." This seems to contradict the language earlier in the clause, and seems to gut the intent of disclosure.

Clause 3 also states "operators will implement measures consistent with state law to assist medical professionals in quickly obtaining trade secret information." Such information should be readily available to medical professionals and first responders in advance of any accident, emergency, or potential exposure.

Performance Standard #9: Clause 1 specifies that "all pipeline-quality" gas during well completion and re-completion be directed into a pipeline for sales. This implicitly exempts gas that is not considered pipeline quality and would need some treatment in order to become pipeline ready. This exemption may provide a giant loop hole that allows flaring instead of green completions at the time of well completion and re-completion. An operator would only need to declare that the gas flared was not of pipeline quality (which is a term not defined by the CSSD standards).

Further, while clause 1 includes all wells for re-completions and workovers (if the gas is pipeline-quality), only development wells are included in this standard for the time of well completion. Exploratory wells and extension wells are not included (see footnote #4). This exemption provides another giant loophole to operators, since they can declare whether or not the wells are exploratory or extensions. The CSSD does not adequately define these terms.

Clause #2 prohibits the venting of gas, and instead requires flaring (burning) if gas is not captured and moved to sales. However, footnote #5 states that "for purposes of this standard, venting does not include the de minimis fugitive emissions from gas busters." De minimis emissions are not defined, which opens up another huge loophole that is apparently left to the judgment of operators, who could in fact be allowed to vent natural gas to the atmosphere (an extremely poor idea in terms of greenhouse gas consequences: Howarth et al. 2011, 2012a, 2012b). The footnote goes on to state that "immediately upon detection of gas in the flowback, operators must divert the flowback into reduced emissions completion ("REC") equipment." This is far too vague, and the standard is weak on guidance as to how, for instance, operators are expected to detect gas in flowback, or indeed what "gas in flowback means." There is always some gas in flowback, but the quantity varies from well to well and for any given well over time. To have teeth, the CSSD standards must define what level of gas is of concern or what level of emission is considered acceptable (together with a compelling explanation as to why it is acceptable). "Immediately" should also be defined, since no engineering operation can respond instantly to a detected issue. Further, the CSSD standards provide no guidance as to what level of performance for reduced emissions completion equipment is acceptable; no technology operates with 100% efficiency, and the green-completion approach has little or no publicly available data on efficiencies of recovery and reduction in methane pollution (Howarth et al. 2011).

Clause 3 provides further exceptions to the rule in clause 1, stating that it is acceptable to flare gas rather than capture it for market if the gas is of low flammability or for "safety reasons." The standard does not provide specific information on what constitutes an acceptable level of low flammability. And providing an exception for safety reasons without any definition or guidance as to what constitutes a safety issue provides another giant loophole.

Clause 4 gives examples of reasons for which it would not be acceptable to flare gas, but again, the standard is vague. Wells that are designated as exploratory or extension wells "using SEC definitions" are exempt, although the clause urges that flaring be minimized "where possible." The SEC definitions are not well defined, were developed at a time before shale gas development exploded and are focused instead on conventional natural gas, and are intended to protect investors in the oil and gas industry, not regulate environmental pollution. Further, the term "minimize" is vague and not defined and "where possible" provides another loophole that is apparently left to operator judgment.

Clause 5 calls for documentation and records "maintained by the Operator" whenever any "upset" or "unexpected conditions" lead to flaring of gas. There is no mention of reporting such information to public agencies, or to the public, and "upset' and "unexpected" conditions are not defined. It is not apparent how information can be useful if not available to regulators and the public.

In clause 6, "exploratory" wells and "extension" wells are defined. However, the definitions are vague, which is a large problem since clause 1 states that the standard does not apply to such wells. An exploratory well is defined as a "well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir." The terms "field" and "reservoir" are not explicitly defined. This is problematic for shale gas fields since the idea of a reservoir comes from conventional natural gas, where gas is contained in pockets below impermeable layers (i.e., well defined "reservoirs"); in shale gas, the whole concept of a reservoir may well not apply and is at best inherently vague. If left to the judgment of operators, this vagueness provides another giant loophole. An extension well is defined as "a well drilled to extend the limits of a known reservoir." This also is incredibly vague when applied to shale gas; almost any shale-gas well might potentially be considered an extension well, under this definition. This clause may allow an operator to claim that any shale gas well is either an exploratory well or an extension well, and therefore not subject to the CSSD rules that specify green completions.

Performance Standard #10: This standard recognizes that flaring is permitted during some well completions, re-completions, and workovers, and sets requirements for such flaring. Clause "a" and footnote #6 specify a 98% efficiency for flaring methane; the footnote allows for the use of sour gas (high hydrogen sulfide) if "only field gas is available and it is not sweetened at the sites;" flaring such gas would contribute significantly to sulfur pollution and downstream acid rain. The footnote also sets a very low bar for the emissions from flaring, simply limiting "visible emissions" rather than setting limits on emissions of fine particles, soot, nitrogen gases, and sulfur gases. Sulfur and nitrogen gas pollution are never visible, and pollution from particles and soot are visible only at very high levels. At that, the standard allows visible emissions at a rate of 5 minutes for every two hours of flaring. This could be a major source of local air pollution.

Clause "b" limits flaring to 14 days for development wells and to 30 days for exploratory or extension wells; these times are very long in terms of the average time of well completion, which are usually shorter than these times (Howarth et al. 2011), and therefore extremely lenient. Further, extensions are allowed for the 30 day limit if required by the operation; this provides another loophole for operators, who presumably are the ones to determine if the continued flaring is required. Footnote #7 implies that acceptable reasons for continued flaring would be "upset conditions," "well purging," and "evaluation tests." Operators would be required to document the reasons for the additional flaring, but the standard does not specify that this be publicly reported or subject to public inspection. Nor are terms such as "evaluation tests," "upset conditions," and "well purging" defined.

Performance Standard #13: This standard specifies controls to achieve at least 95% reduction in volatile organic carbon (VOC) emissions, but only for storage vessels at the well pad that have VOC emissions of 6 tons per year or greater. For the average shale gas well with a lifetime production of approximately 0.3 billion cubic feet (USGS 2012), the 6 tons per year emission cut off corresponds to approximately 0.2% of the lifetime production of the well emitted as methane, which is a high level of emission for just one component of the natural gas industry. For context, the greenhouse gas emissions from an in-home natural gas water heater exceed those of using coal-generated electricity to power a heat pump for domestic hot water, if the total methane emissions are 0.7% or higher (Howarth 2014).

Performance Standard #14: Clause 2 specifies that pneumatic controllers should emit less than 6 cubic feet per hour. Although these "low-bleed" controllers are better than what the industry often uses, a far better option would be electric or compressed-air controllers, which emit no methane or other volatile organic carbon (EPA 2006). Cumulatively, the emissions associated with controllers that are emitting up to 6 cubic feet per hour can be significant, and such emissions are simply not necessary.

Clause 4 calls for inspection and maintenance for all valves, pump seals, flanges, compressor seals, pressure relief values, etc. Weekly monitoring by visual, auditory, and olfactory checks are specified, with an annual "mechanical or instrument" check. "Visual, auditory, and olfactory checks" are inherently insensitive, particularly when looking for an invisible and odorless gas (methane) in a noisy environment (note that additives are used to make natural gas sensitive to the nose in downstream distribution systems, but these have not yet been added at the well site). The CSSD standards give no guidance as to what would constitute the "mechanical or instrument" check, nor any explanation as to why making such checks just once per year is sufficient. Far better and more sensitive technologies for monitoring methane emissions are available, including methane-tuned FLIR video cameras. Further, the clause states "once significant leaks are detected, they are required to be repaired in a timely manner." This language is very weak: "significant leaks" is not defined, nor is the requirement of repairs in "a timely manner."

Clause 5 says only "de minimis emissions are permitted" in association with well-bore freezing, but the de minimis amount is not defined or specified, leaving this to operator judgment.

Clause 6 requires that compressors be pressurized, in recognition that non-pressured compressors can emit significant quantities of gas to the atmosphere. However, other technologies for starting compressors exist, including electric starters instead of using the pressure of natural gas to start compressors. The CSSD standards give no indication as to why they chose the more methane-polluting approach.

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Executive Summary

CSSD Performance Standards: Water and Contaminant Transport Review

Performance Standards reviewed: Numbers 1, 3, 5, 6, and 7

Paul Rubin

The Center for Sustainable Shale Development (CSSD) Performance Standards were drafted in an attempt to demonstrate to regulators and the public that the industry will establish and follow best industry practices and, in doing so, can exploit gas resources safely. Unfortunately, both the practices advocated and the needed supportive criteria are sorely lacking. The CSSD Performance Standards will not make shale gas development safe. They fail to protect human health and the environment, including aquatic ecosystems.

- **Performance Standard No. 3** states that any new pits shall be double-lined and equipped with leak detection. Open pits are unacceptable as a practice due to the multiple pollution pathways that they provide and the lack of technical solutions to prevent airborne and waterborne contaminant transport to humans and wildlife. Liner failure has occurred both along seams and elsewhere and, sometimes, from animals who have fallen into and are seeking to escape. These pits are vulnerable to failure and are documented to leak contaminants into the subsurface. The one-sentence standard provides no measurable performance criteria or objective.
- **Performance Standard No. 6** (1) erroneously infers that monitoring groundwater quality for a maximum distance of 2,500 feet from a gas well wellhead for as little as one year, as stated in Performance Standard No. 6 (2), is sufficient to determine if any water quality problems exist. Toxic gas industry chemicals (i.e., hydraulic fracturing and drilling fluids) migrate laterally and upward prior to discharging into freshwater aquifers and rivers where homeowners, farmers, and municipalities extract it. Hundreds of chemicals injected underground do not return to the surface in the form of drilling, flowback and produced waters. They flow within interconnected fractures and faults in bedrock and eventually discharge down gradient where large population centers concentrate. This wastewater contaminates the Waters of the Commonwealth of Pennsylvania and other states, making it impossible for drillers to comply with Performance Standard No. 1. A confining layer above the production zone will not prevent adverse migration of hydraulic fracturing fluids as is postulated in Performance Standard No. 5. This poses a serious threat to public health.
- **Performance Standard No. 7** erroneously assumes that isolation and protection of freshwater aquifers can be achieved and maintained indefinitely via a series of steel casings and cement sheaths. Cement sheath failure and casing corrosion both are mechanisms that compromise the isolation of freshwater aquifers. Under ideal conditions cement and steel may last 80 to 100 years, often far less. Thereafter, gas industry contaminants may move along failed borehole pathways into freshwater aquifers, rivers, and reservoirs. Once toxic contaminants are detected in regional aquifers, monitoring will be of little value because contaminant laden plumes will continue to arrive indefinitely and with them public health will be jeopardized for generations into the future.

Simply put, there are no performance standards that can make the intentional injection of vast quantities of toxic wastewater (i.e., hydraulic fracturing and drilling fluids) into actively moving groundwater flow systems safe for public consumption.


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CSSD Performance Standards: Water and Contaminant Transport Review

Paul Rubin*

Overall: The Center for Sustainable Shale Development (CSSD) Performance Standards will not make shale gas development safe. The stated goal of "*zero contamination of fresh groundwater and surface waters*" is impossible to attain. The three most significant reasons for this are 1) gas industry chemicals will migrate within deep and shallow groundwater flow systems, eventually discharging in freshwater aquifers (even below numerous confining layers), 2) the standard does not prohibit disposal of wastewater by deep well injection (a waste disposal method analogous to injection of toxic fracking fluids) into deep groundwater flow systems that eventually discharge into freshwater aquifers, and 3) the durability and mechanical properties of gas well sealant materials (primarily cement and steel) are not sufficiently protective of freshwater aquifers for even as long as 100 years, let alone longer – regardless of the number of nested casings (i.e., multiple barriers) used for zonal isolation through freshwater aquifers or cement used to plug and abandon wells. The elements of groundwater flow, corrosive downhole environments, and time have not been factored into the Performance Standards. Industry studies that largely examine failure incidents during the productive lives of oil and gas wells are considering the wrong endpoint: it is not sufficient to only consider the "*life of the well,*" but instead the life of the aquifer must be considered. For these reasons, environmental protection of ground and surface water cannot be achieved through these Performance Standards.

The subsurface waste disposal practice (i.e., introduction of vast quantities of toxic chemicals into the groundwater environment) advocated in the CSSD Performance Standards fails to recognize groundwater modeling studies that suggest that gas industry contaminants may reach freshwater aquifers within time frames measured in hundreds of years (Myers, in review), and potentially even a decade time frame (Myers, 2012).

Inherent in the Performance Standards is the erroneous underlying concept that a groundwater monitoring program is capable of documenting the full lateral and vertical extent of groundwater contamination that results from contaminant injections (i.e., deep waste disposal, hydraulic fracturing) on such an unprecedented scale into groundwater flow systems that recharge our aquifers. As is beginning to be seen in Florida, for example, deep contaminant injection will eventually surface (Rubin**1**).

Regarding monitoring for individual gas wells, because large portions of groundwater flow systems move slowly (vs. more rapid preferential flow through fault and failed wellbore pathways), the recommended "*periodic monitoring for at least one year following completion of the well*" will do little to adequately monitor long-term water quality at distant receptor locations or, more importantly, the health of the human population that will be exposed to the toxic chemicals. In contrast, the CSSD's performance standards imply that groundwater monitoring can effectively be performed on both a local and short-term basis proximal to individual gas wells. To be of meaningful value, contaminant monitoring must consider both local and regional groundwater flow systems and groundwater flow rates far in excess of one year.

The practice of injecting toxic chemicals into subsurface groundwater, regardless of whether it's labeled hydraulic fracturing or disposal of wastewater by deep injection, amounts to the sanctioned release of slow-moving toxic chemicals into current or future water supplies. In both cases toxic chemicals are released into the deep groundwater flow regime (or system if you prefer to use the word system or maybe environment) where they steadily move toward valley bottom aquifers and rivers used by our major population centers. Once toxic contaminants are detected in regional aquifers, monitoring will be of little value because contaminant laden plumes will continue to arrive indefinitely and with them public health will be jeopardized for generations into the future. Studies suggest that some of these waste materials, including the radioactive elements, can, in very small concentrations, cause serious, sometimes life-threatening illness. Worse, in areas that have high background loads of radiation or heavy metals or that have suffered previous toxic contamination, the effects of additional contamination may be cumulative or even

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synergistic (Nolan and Rubin, 2014).

Simply put, there are no performance standards that can make the intentional injection of vast quantities of toxic wastewater into actively moving groundwater flow systems safe for public consumption.

The CSSD Performance Standards do nothing to protect public health after production and short-term monitoring cease. Industry experts note that the pressure inside producing oil and gas wells drops constantly during primary production (e.g., King and King, 2013). However, once production ceases and wells are abandoned, downhole pressures will increase as will the risk of sealant corrosion and excursions.

The CSSD Performance Standards fail to provide any type of cleanup or remedial goals for contaminated local and regional aquifers once contaminant arrival occurs within continuously moving groundwater flow systems. Additionally, the Performance Standards do not address responsibility and costs associated with clean-up of polluted groundwater systems, developing alternate water supplies or public medical monitoring and treatment in the event of contaminated groundwater supplies and/or other pathways of exposure.

The CSSD Performance Standards are too generalized to be of value. Furthermore, their great reliance on decisions to be made by oil and gas industry operators fails to provide objective and transparent criteria that can be judged by non-industry experts or reviewing agencies and instead injects a variety of conflicting approaches that undermine the concept of performance based standards equally applicable to all. Portions of some performance standards demonstrate that either 1) those responsible for developing them do not understand basic hydrogeologic principles associated with groundwater flow and contaminant migration, or 2) they intentionally seek to erroneously convince reviewers of the standards that widespread underground injection of vast quantities of toxic chemicals into the subsurface poses no water quality or health risks.

Performance standards that have operators developing and implementing a plan for monitoring existing water resources, including aquifer and surface waters, fail to ensure the scientific knowledge, rigor and integrity necessary. Monitoring plans must be developed and must have oversight by independent experts. Furthermore, the underlying premise of a performance "standard" is that a scientifically valid "standardized" method will be used for consistent monitoring procedures throughout the industry, perhaps with only minor alteration for site-specific physical conditions. The CSSD Performance Standards are wholly deficient, in that they are devoid of any meaningful standards that might be uniformly applied throughout the gas industry.

<u>Performance Standards: General</u>

The CSSD "Performance Standards" are not professional quality performance standards. For the most part, they are without any meaningful substance and should not be construed as being performance standards. Professional engineering performance standards encompass detailed technical requirements designed to meet specific objectives, such as protecting people's health and the environment. The short CSSD white paper is not a professional quality document.

Reference to real-world comprehensive professional performance standards reveals cohesive organization structures that incorporate much well thought out material, including a table of contents, an executive summary, an overview introduction, statements of performance standard objectives, document organization, definitions, background information, need and rationale for developing performance standards, fundamental principles of development, statutory landscape discussion, legal authority, reference to related studies, guiding principles, data analysis and testing information, tables and figures, supportive appendices, proposed performance standards, supporting discussion, implementation details, evaluation of data collected to confirm standards have been met, criteria and action levels, data quality objectives, quality assurance and quality control, monitoring, means of verifying standards, discussion of effectiveness of the proposed standards, reporting and notifications, oversight, enforcement, etc. An excellent example of what a performance standard should include is the highly detailed, professional-quality, engineering performance standards prepared for the Hudson River PCBs Site (US EPA and US ACOE, 2010).

Engineering performance standards and methods are typically developed and peer-reviewed by numerous experts before they are considered complete. For example, ASTM (American Society for Testing and Materials) International is an international organization recognized worldwide for their rigorous development of technical standards for materials, products, systems, and services. ASTM standards provide exacting criteria designed to ensure consistency. The level of detail in these standards is lacking in the CSSD Performance Standards. In short, the CSSD Performance Standards lack sufficient information and detail to warrant consideration of any kind. They should be discarded. Until such time as they are discarded, the comments below provide documentation supporting this conclusion.

Performance Standard No. 1

1. Operators shall maintain zero discharge of wastewater (including drilling, flowback and produced waters) to Waters of the Commonwealth of Pennsylvania **and other states** [emphasis added] until such time as CSSD adopts a standard for treating shale wastewater to allow for safe discharge. Such standard will be adopted by September 1, 2014.

*Note: This standard does not apply to nor prohibit disposal of wastewater by deep well injection. (*CSSD, p. 1).

Comments

While on paper this goal sounds commendable, in reality the standard is unachievable because only a portion of the wastewater injected underground is recovered. The standard fails to protect the environment because it fails to recognize the connectivity between chemically-laden frack waters injected into the ground and our freshwater aquifer systems, and it fails to recognize that other alternatives for addressing wastewater are themselves unsustainable and harmful. Due to the large volume of water used in gas well stimulation through hydraulic fracturing in deep shale formations, vast quantities of wastewater are generated from development and production activities, much of which is temporarily stored in drill cuttings pits and impoundments.

The CSSD standards fail to protect human health and the environment, including aquatic ecosystems. Presently, means used to "… *maintain zero discharge of wastewater to Waters of the Commonwealth of Pennsylvania and other states* …" (CSSD, p. 1) are not adequate and fail to achieve this goal. The public is exposed to frack wastewater chemicals through several mechanisms: 1) fluids delivered to treatment plants unable to remove the contaminants; 2) waste materials inadequately contained at landfills; 3) legally authorized applications to roads and fields; 4) intentional, illegal dumping in fields and streams; 5) toxic spills during transport; 6) leaching from toxic wastes buried at or near fracking sites; and 7) direct contamination of drinking water sources from fracking activities (Nolan and Rubin, 2014). Most of these routes of contamination pose a threat to areas that can be far removed from the site of fracking activities.

As an example, spreading production brine from natural gas and oil wells on roads for purposes of dust suppression, road stabilization, and deicing - all activities permitted by the New York State Department of Environmental Conservation during the past decade (Riverkeeper, 2014) – is hydrologically equivalent to pouring toxic materials directly into our waterways.. The chemicals, brine, and waste residues can run directly from the roads into ditches and then almost immediately into surface waters. Similarly, materials leaching from landfills or spilled during transport will invariably flow under the pull of gravity down to groundwater and surface water receptors. Landfill disposal, wastewater treatment plant processing, burial on gas well sites, and land spreading means of disposing of drilling, flowback and produced waters are not sustainable practices. Wastewater disposal via each of these means does, in fact, have a high likelihood of leaching into " … *Waters of the Commonwealth of Pennsylvania and other states* ..." (CSSD, p. 1).

The underlying premise erroneously advanced in this Performance Standard is that only contaminant laden waters that return to the surface from wells, and then characterized as "wastewater", are of concern to public health. The standard fails to acknowledge that large quantities of drilling and hydraulic fracturing related fluids introduced downhole during drilling and hydraulic fracturing activities enter actively flowing groundwater systems that eventually discharge to freshwater aquifers and waterways. The chemically-laden produced and flowback waters that return to the surface are only a portion of the chemically-laden drilling fluids injected into the subsurface during hydraulic fracturing that are of concern for water contamination. Wastewater that remains downhole enters and moves with groundwater to " … *Waters of the Commonwealth of Pennsylvania and other states* ..." (CSSD, p. 1) where major population centers as well as smaller municipal system users and privately owned water well users require clean, potable, groundwater and surface water. Thus, the goal of this Performance Standard (i.e., zero discharge of wastewater to waters of the Commonwealth) cannot be maintained by Operators.

Public health and safety is the greatest concern relative to underground injection during fracking (i.e., downhole use of drilling and hydraulic fracturing related waters during well development) of toxic chemicals for gas well development. Because gas industry chemicals will eventually enter freshwater aquifers, it is important to know something of their toxic nature. While hundreds of chemicals are used throughout the gas well development process, many being unidentified proprietary chemicals, review of some of these chemicals accents potential health risks the public is asked to bear in accepting the draft CSSD Performance Standards. Clearly, Operators cannot maintain zero discharge of wastewater to "*Waters of the Commonwealth of Pennsylvania and other states*" because they are injecting toxic chemicals into actively flowing groundwater systems that discharge to freshwater aquifers.

Performance Standard No. 3

1. Any new pits designed shall be double-lined and equipped with leak detection (CSSD, p. 2).

Comments

Open pits are unacceptable as a practice due to the multiple pollution pathways that they provide and the lack of technical solutions to prevent airborne and waterborne contaminant transport to humans and wildlife. Liner failure has occurred both along seams and elsewhere and, sometimes, from animals who have fallen into and are seeking to escape. The one-sentence standard provides no measurable performance criteria or objective.

Performance Standard No. 3 fails to provide the exacting engineering specifications (e.g., detailing construction materials, material thicknesses, material permeability, material tensile strength, liner sealant method, invert specifications, invert grade and composition specifications, side slope angles, specifications of material below and between liners, leak detection setup, piping details, pumping specifications, monitoring equipment, monitoring locations, monitoring frequency, parameters to be monitored, contaminant collection procedures and frequency, shut down procedures, emergency response protocols, liner removal procedures) necessary to offer any meaningful guidance. No construction details or criteria are provided regarding liner thickness, liner material and chemical resistance, the thickness of engineered permeable zones, the homogeneity and areal continuity of materials used, the spacing and materials to be used between liners, the hydraulic means by which contaminant leakage will occur, or the engineering design and number of drains and collector systems.

The few words of the Performance Standard fail to address how or where leak detection will occur. This Performance Standard fails to address engineering requirements needed to establish a hydraulically functioning physical setting capable of providing an effective leak detection system over expansive pit or impoundment dimensions. The leak detection Performance Standard fails to put forth any criteria that can be evaluated to determine if effective and comprehensive monitoring is possible either below double liners or preferably between them. The standard fails to clarify whether leak detection will occur below a double liner and/or between liners.

Furthermore, no discussion or performance standard detail is provided to address monitoring frequency, what parameters will be monitored, reporting requirements, and what actions will be taken if leaks are detected. This is not an adequate performance standard.

Waste burial in pits has historically been one of the greatest sources of contamination. For example, King and King (2013) found that 57 of 75 waste-related incidents in Texas stemmed from disposal pits that were outlawed in 1969. One of the greatest risks of contaminant introduction into the subsurface occurs when decommissioning pits. The performance standard fails to address this critical issue. Use of heavy equipment commonly rips liners, thereby permitting contaminant excursions. These excursions can provide significant and large volume contaminant point sources up-gradient of homeowner wells.

Performance Standard No. 3 lacks the background information and justification that are typically found in well-constructed performance standards.

Performance Standard No. 5

1. Operators shall establish an Area of Review (AOR), prior to drilling a well, which encompasses both the vertical and horizontal legs of the planned well. Within the AOR, the Operator must conduct a comprehensive characterization of subsurface geology, including a risk

> analysis that demonstrates the presence of an adequate confining layer above the production zone that will prevent adverse migration of hydraulic fracturing fluids. As part of the risk analysis, and before proceeding with hydraulic fracturing, the Operator must also conduct a thorough investigation of any active or abandoned wellbores within such area of review or other geologic vulnerabilities (e.g., faults) that penetrate the confining layer and adequately address identified risks (CSSD, p. 3).

Comments

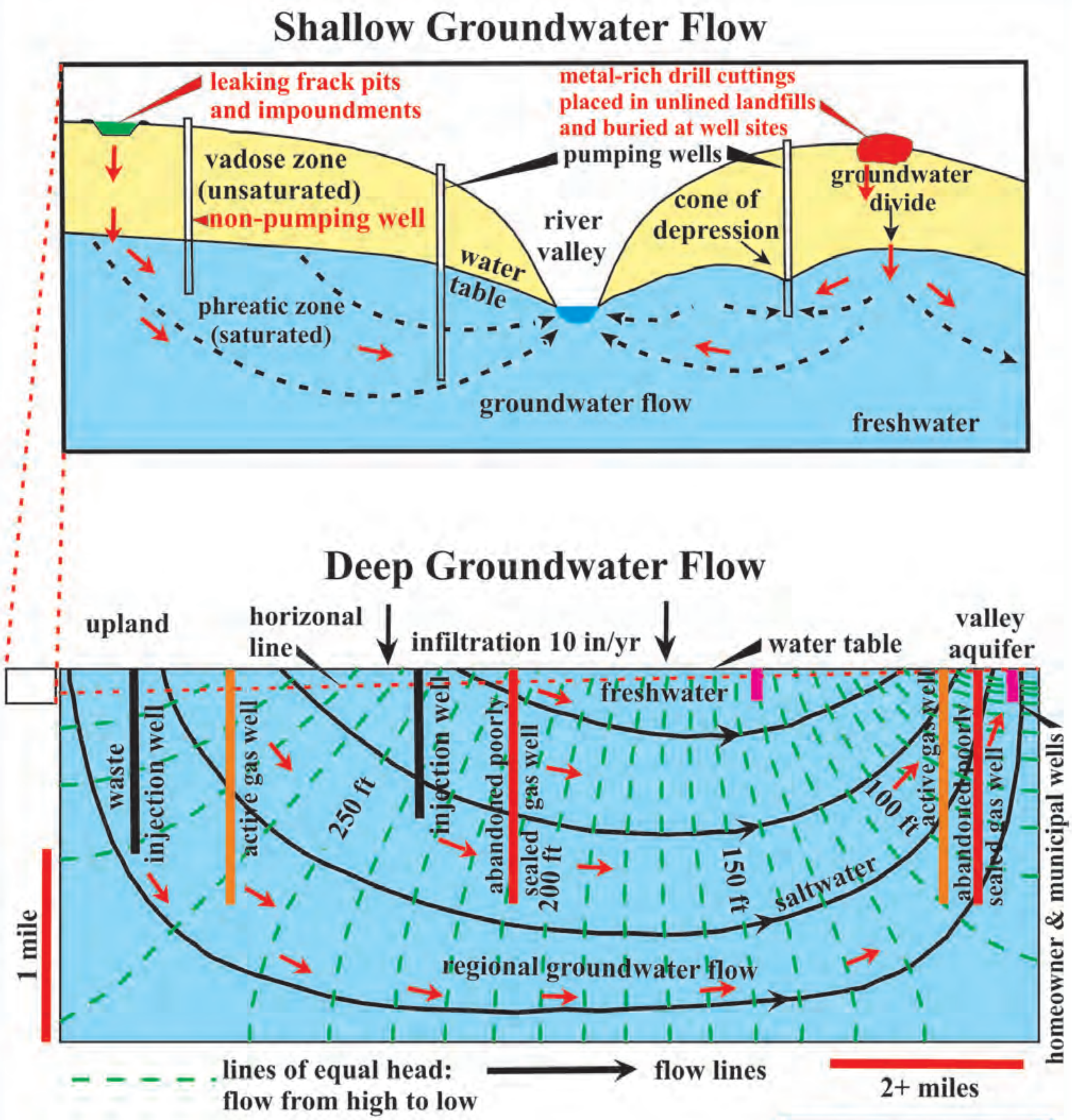
Performance Standard No. 5 fails to acknowledge that gas and oil industry chemicals injected deep underground will move within both deep and shallow groundwater flow systems beneath confining layers until they eventually rise and enter freshwater aquifers. The presence of confining layers above production zones may only temporarily preclude contaminant migration upward into freshwater aquifers. As written, this performance standard ignores basic hydrologic principles of groundwater flow. The underlying concept advanced in this performance standard requires that Operators "*conduct a comprehensive characterization of subsurface geology, including a risk analysis that demonstrates the presence of an adequate confining layer above the production zone that will prevent adverse migration of hydraulic fracturing fluids* (CSSD, p. 3)."

This characterization is impossible to make anywhere in the Appalachian Basin because it assumes that both deep and shallow groundwater flow vectors, as are well illustrated in all basic and advanced hydrogeology text books, would cease to flow or, to put it another way, that these vectors are static. Hydraulic fracturing fluids that enter and are dissolved in deep groundwater WILL migrate with natural groundwater flows and they WILL rise upward and mix with freshwater aquifer water – either far down gradient or closer when vertically continuous fault and fracture networks extend from great depth upward to freshwater aquifers.

The operative AOR for this performance standard would need to extend far from each gas well array to regional base level river valleys where hydraulic fracturing fluids will eventually rise. Even then, this performance standard would not be able to stop the migration or subsequent contamination that would follow. Confining layers above production zones do not stop the steady flow of groundwater to distant discharge locations. Thus, the underlying premise of this performance standard, as stated in the CSSD Performance Standards and in gas industry advertising, fails to account for dynamic, natural groundwater flow. Therefore, this performance standard is fundamentally flawed and cannot be achieved.

Gas industry chemicals injected into gas-rich Appalachian Basin shale formations (e.g., Marcellus, Utica) will migrate as plumes to freshwater aquifers (Rubin**2,3,4,7,8**). Hydraulic fracturing poses a serious threat to groundwater quality, not only in the vicinity of drilling sites, but also in the entire down-gradient part of the groundwater flow system. Although the main injection of contaminants takes place thousands of feet below the surface beneath overlying confining layers, groundwater flow inevitably carries them laterally and then upward into major neighboring river valleys over periods of years to hundreds of years, tailing off for possibly thousands of years (as depicted in Figures 1 and 2). In the Appalachian Basin, valleys are where most people live because communities tend to develop on wide, gently-sloping, or flat valley bottoms with arable land close to rivers suitable for power generation, irrigation, and transportation. Valleys tend to have excellent groundwater supplies, commonly tapped by wells, because upland recharge areas discharge there. Contaminants are widely dispersed, but they pose a threat to health, especially when thousands of hydraulically fractured wells are involved (see Figure 1 and 2: Shallow and Deep Groundwater Flow).

This performance standard lacks technical basis for establishing AORs. Professional quality performance standards require great detail, as is discussed on page three of this report (e.g., US EPA and US ACOE, 2010) and in the setback example here. To date, various regulators have generally approached this issue from the standpoint of setting "safe" setback distances from wells, streams, and other features. Ideally, these setback distances seek to protect water quality and minimize explosive risk or damage from accidents, such as a fallen drill rig. But to be protective the criteria for both a setback and/or AOR must be established based upon geologic and hydrogeologic variables, not just generic distances, and they need to be ascertained by professional hydrogeologists, not by oil and gas industry operator auditors as contemplated in the Performance Standard.



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Regional flow of groundwater from uplands to valleys. Gas industry chemicals and other contaminants injected deep underground AND those that leak from both poorly sealed active gas wells and abandoned oil and gas wells will migrate laterally and then upward prior to discharging into freshwater aquifers and river valleys. Faults and fractures intersected by laterals and/or enlarged by repeated fracturing are also significant transport pathways. Chemicals injected during high & low volume hydraulic fracturing operations and underground injection of waste pose a serious threat to groundwater quality and public health, as do metal-rich drilling fluids forced into formations during drilling operations. Figure modified from Palmer (2007, 2012) and U.S.G.S. modeling software by HydroQuest.

Figure 1: Shallow and deep groundwater flow.

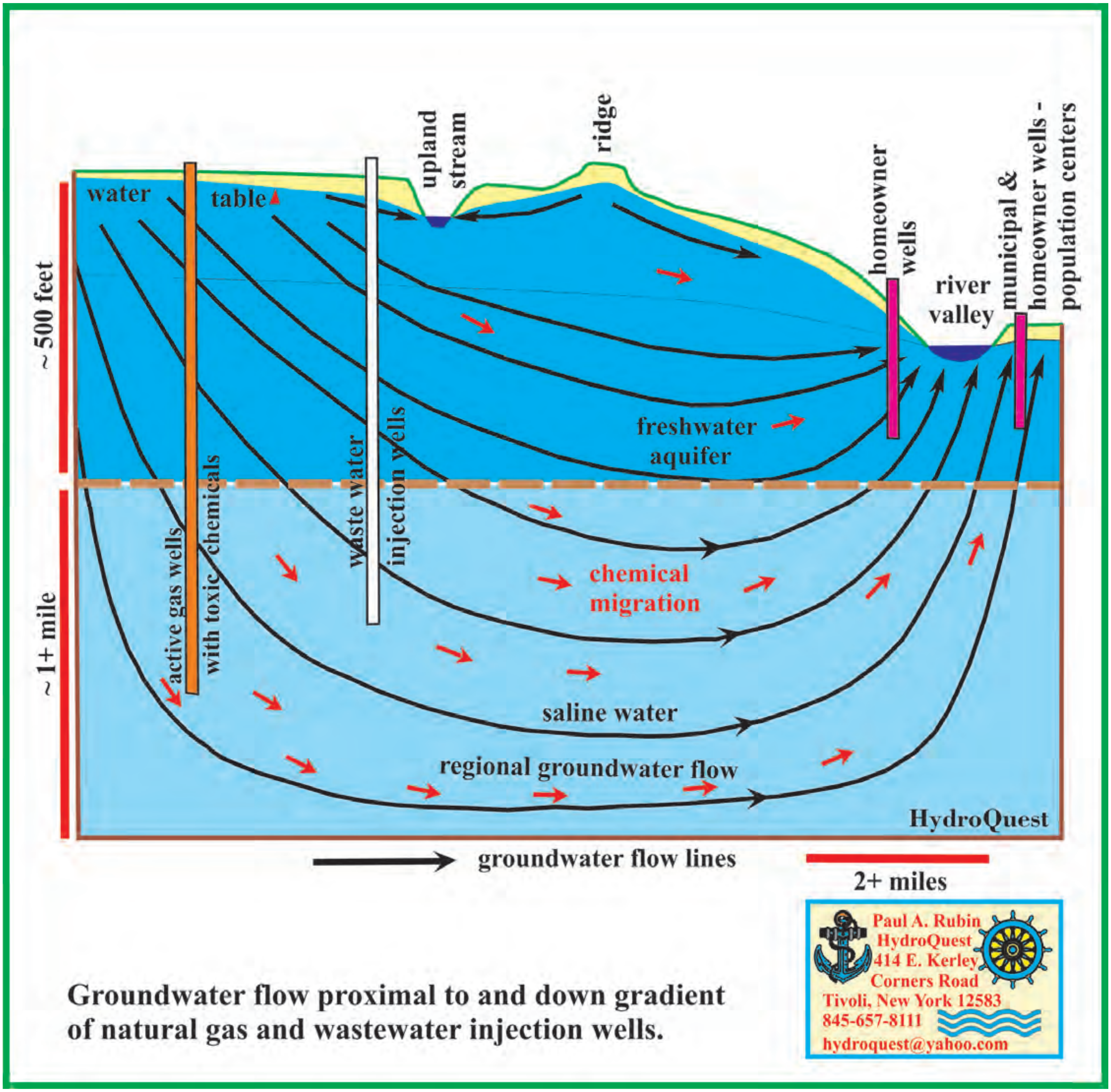


Figure 2: Regional groundwater flow.

Therefore, hydrogeologically, the concept of finite Areas of Review as described in Performance Standard No 5 or setback distances that seek to " … *prevent adverse migration of hydraulic fracturing fluids* …" (CSSD, p. 3) are flawed because groundwater moves. Additionally, groundwater flow rates or travel times (i.e., seepage velocity) vary markedly based on a number of factors which include hydraulic conductivity, hydraulic gradient, and effective porosity. Interconnected faults and fractures in anisotropic media can support flow rates orders of magnitude greater than that in surrounding media. Furthermore, horizontal boreholes and hydraulic fracturing can serve to interconnect formerly isolated faults and fractures, potentially increasing hydraulic conductivity and groundwater flow rates. At best, setback distances are arbitrary in nature because they have not been founded on defensible or reproducible science and they presume to apply generally across large regions (e.g., states) without regard to changes in geology, groundwater flows and surface flow paths that by their nature are variable. AORs must be established independently. Additionally, operators cannot be charged with "*establishing AORs*" because to be effective, AORs must be based on empirical, reproducible, hydrogeologic data that documents fracture (i.e., joint) interconnectivity and, in effect, itself dictates the AOR.

HydroQuest has reviewed two major aquifer tests within the Appalachian Basin (Rubin**4,5**). The Deerpark Village aquifer test documented fracture interconnectivity to a distance of at least 4,300 feet (see Figure 3). Detailed, reproducible, hydrogeologic analyses represent the type of information required, but not provided, in the CSSD Performance Standard. Furthermore, this performance standard fails to take into consideration the increased risk of stray gas migration to homeowner wells situated proximal to fault zones. This Performance Standard fails to provide any empirical data or analyses of this nature that could be uniformly applied as a standard for establishing AORs, thus failing in its goal of sustainable shale development.

Additionally, the Performance Standard provides no criteria or means for Operators to investigate "*other geologic vulnerabilities*" (CSSD, p. 3) presented by joints and faults that may extend downward through freshwater aquifers and confining layers. Yet, scientific data (structural and hydrologic) may be present that must be factored into establishing minimum AORs. Jacobi (2002) has established that natural gas naturally migrates upward from gas-bearing formations along fracture intensification domains (FIDs):

The FIDs are characterized by closely spaced fractures, the strike of which defines the trend of the FID. The closely spaced fractures are also commonly the master fractures, even though they may characteristically abut other fracture sets in regions outside the FID. In interbedded shales and thin sandstones in NYS, fractures within the FID that parallel the FID characteristically have a fracture frequency greater than 2/m, and commonly the frequency is an order of magnitude greater than in the region surrounding the FID. Certain sets of FIDs are marked by soil gas anomalies commonly less than 50 m wide (Jacobi and Fountain, 1993, 1996; Fountain and Jacobi, Fig. 1. 2000). In NYS, the background methane gas content in soil is on the order of 4 ppm, but over open fractures in NYS, the soil gas content increases to 40–1000+ ppm.

As gases and/or hydraulic fracturing fluids migrate upward from depth along faults, fractures, bedding planes, and/or failed wellbores they will enter freshwater aquifers. Gases may express upward through the water table to the atmosphere through fractures, soils, and surface water. Gases will escape upward wherever possible. In the Appalachian Basin, fluids will migrate in aquifers along interconnected joint sets tapped by homeowner wells. This performance standard fails to document relevant scientific literature that is directly applicable in assessment of AORs.

Performance Standard No. 5 does not set forth required methods by which Operators must investigate the presence of abandoned wellbores or require wellbores to be properly plugged. As written, an Operator may only look around for abandoned wellbores or he might review historic records and conduct a magnetometer survey to locate buried wellbores. Standards cannot be discretionary and must be specific.

This performance standard fails to provide technical requirements that use standard hydrogeologic testing methodologies as a basis of establishing the areal extent of Area of Reviews. This is an important omission in the standards that fails to acknowledge documented distances along hydraulically interconnected joint sets.

<u>Performance Standard No. 6</u>

1. Operators shall develop and implement a plan for monitoring existing water resources, including aquifer and surface waters (as defined in the CSSD Guidance for Auditors document) within a 2,500 foot radius of the wellhead (or greater distance, if a need is clearly indicated by geologic characterization), and demonstrate that water quality and chemistry measured during a pre-drilling assessment are not impacted by operations (CSSD, p. 3).

Comments

Performance Standard No. 6 (Paragraph 1) fails to provide justification and rationale for the baseline stated radial monitoring distance of 2,500 feet from wellheads that it sets. Numbers, such as the 2,500 foot radius stated in this performance standard, must be based on empirical, reproducible, data and analyses such as that used by HydroQuest in documenting areas of potential adverse impacts (see Figure 4).

Performance Standard No. 6 also states that "*Operators shall ... demonstrate that water quality and chemistry measured during a pre-drilling assessment*

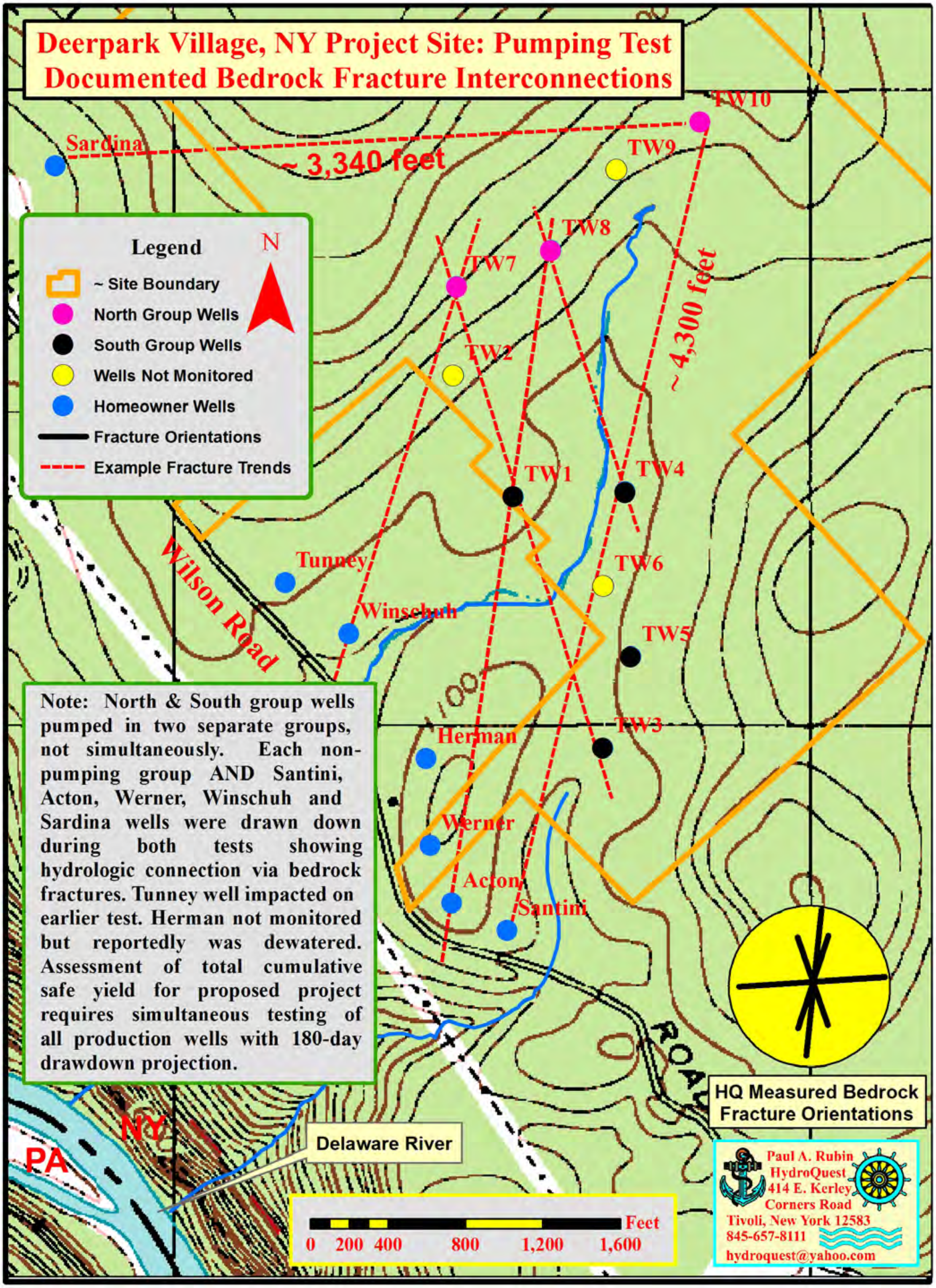


Figure 3. The Deerpark Village, NY aquifer test documented fracture interconnectivity to a distance of at least 4,300 feet in the Appalachian Basin (Rubin**5**).

are not impacted by operations." Since oil and gas industry research and documentation clearly establishes that cement and steel wellbore sealant materials will almost certainly fail in less than 80 to 100 years (e.g., Rubin**2,3,4,6,7,8**), and quite likely in far less time, this performance standard has the potential of characterizing water quality and hydrogeology in advance of gas well sealant failure. However, the complete lack of detail regarding what chemical parameters will be analyzed, the methods to be used, the method detection limits, quality assurance and quality control, etc., obviate the utility of this as a performance standard. Again, as an example of the type of information that is lacking in CSSD performance standards, see US EPA and US ACOE (2010).

Performance Standard No. 6 (Paragraph 1) fails to provide any scientific justification for specific standard monitoring or rationale for what is stated. There is no empirical data to support use of the 2,500 foot radius from wellheads, no stated chemical parameter list that would insure consistent uniformity between well sites, and no guidance relative to monitoring. Under this Performance Standard above, twenty different operators could easily arrive at a single well site with twenty different interpretations of the "standards." There is nothing to provide operators with rigorous, empirically-based, standards to proceed consistently between well sites.

Performance Standard No. 6

2. Operators must conduct periodic monitoring for at least one year following completion of the well. Such monitoring must be extended if results indicate potential adverse impacts on water quality or chemistry by operations (CSSD, p. 3).

Comments

Regarding the length of monitoring, more often than not, sealant failure will occur sometime after one year when draft CSSD Performance Standard No. 6 (Paragraph 2) monitoring is no longer being conducted. This standard does not take into consideration distance and contaminant travel time. Natural groundwater flow takes time to traverse between contaminant point sources (e.g., gas wells) and down gradient receptors (e.g., wells, springs and waterways), often many years. Performance Standard No. 6 (Paragraph 2) fails to establish long-term monitoring locations, far removed from well pads, which will allow evaluation of deep and shallow groundwater flow vectors that may transport contaminants far from any on-site or near-site monitoring locations (see Figure 1; shallow and deep groundwater flow). As a result, this standard would prematurely relieve operators of responsibility for aquifer degradation, thereby leaving homeowners with unsafe water supplies in future years and no one to assume financial and replacement responsibility. Sealant failure may occur either slowly or catastrophically during high pressure hydraulic fracturing operations or during seismic events or ground motions imposed by adjacent well drilling operations. Once polluted with chemicals, the aquifer will be permanently degraded with no viable corrective action.

Performance Standard No. 6 fails to list target chemicals for testing and monitoring, and, does not provide any guidance on prioritization of parameters to be tested based on human health effects or ecological impacts, which should be provided based on medical expert input.

Performance Standard No. 6

3. In the event that monitoring establishes a possible link between an Operator's activities and contamination of a water source, the Operator shall develop and implement an investigation plan and, if a positive link is established, implement a corrective action plan (CSSD, p. 3).

Comments

Performance standard No. 6 (Paragraph 3) fails to provide a rigorous, defensible and reproducible, set of groundwater investigation standards whose performance can be evaluated. No protocols are provided relative to monitoring well depths, numbers, construction, placement, monitoring frequency, assessment of baseline groundwater chemistry, assessment of groundwater flow direction, chemical parameters to be tested, characterization of hydrogeologic coefficients, etc. No information is provided relative to potential corrective action plans, goals of corrective actions, or evaluation of alternate and permanent water supply options. Furthermore, the standard fails to discuss the most likely scenario that corrective actions are almost certainly impossible, as once groundwater contamination has occurred aquifer restoration is essentially impossible. Expansive vertical and horizontal dispersion of contamination deep within regional flow systems precludes remediation using

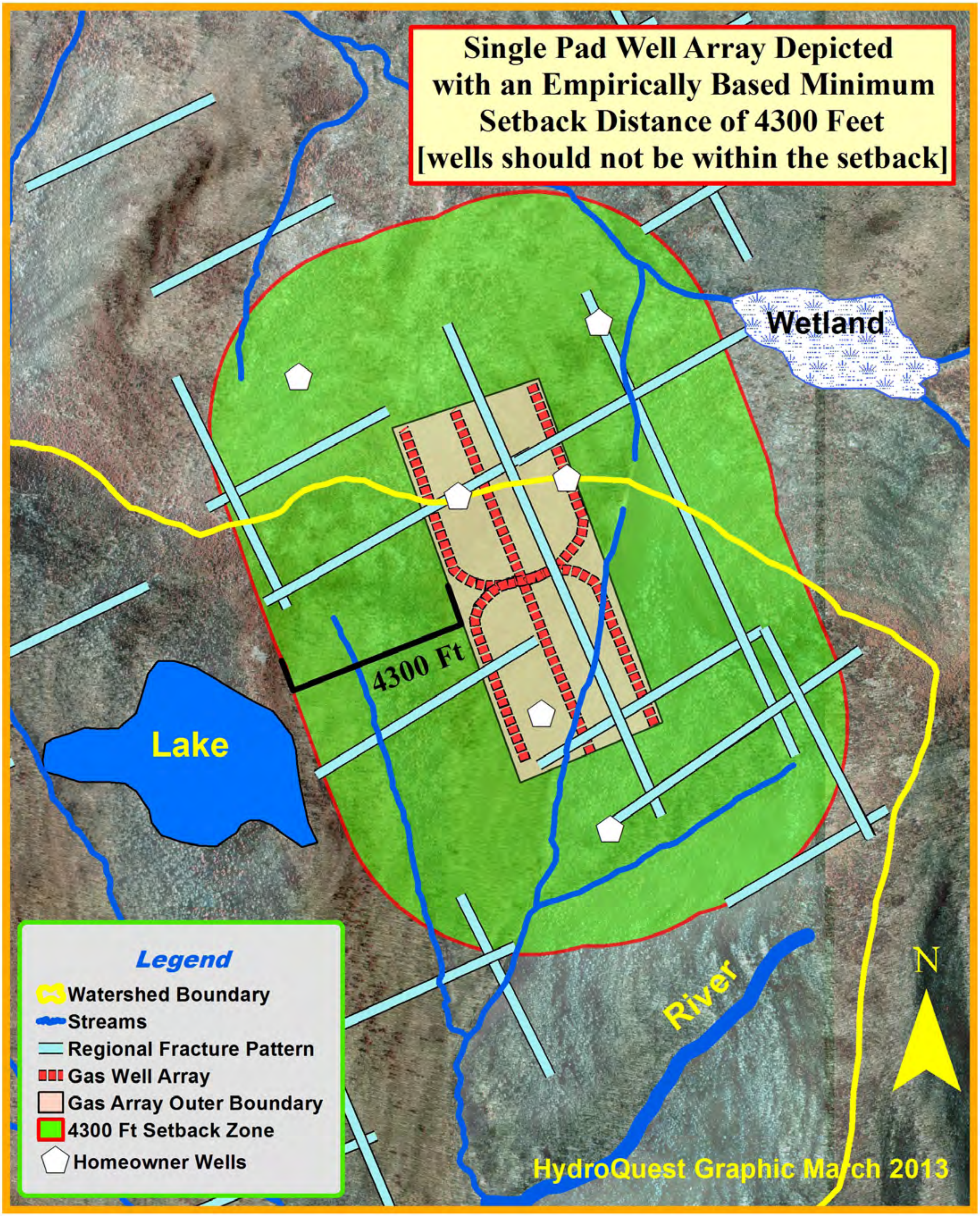


Figure 4. Performance Standard No. 6 suggests water resource monitoring should be conducted within 2,500 feet of a wellhead. This value lacks scientific basis and does not consider groundwater flow. Hydrogeologic and geologic analyses conducted by HydroQuest used empirical data to determine that the area of water quality monitoring should initially extend a minimum distance of 4,300 feet outward from horizontal gas well arrays. Allowing for groundwater flow velocities, this distance should be extended in down gradient directions.

existing technology. Additionally, once initiated, groundwater contamination will continue to degrade water sources for generations as pollutants continue to flow between gas wells and receptors. The underlying conceptual basis of this standard erroneously implies that corrective actions, other than procuring and piping in alternate source waters, will be feasible. This "standard" fails to provide any standards for evaluative purposes. In addition, it is unlikely that operators have the hydrogeologic expertise to develop and implement an effective investigation plan without specific standards.

Performance Standard No. 7

1. Operators shall design and install casing and cement to completely isolate the well and all drilling and produced fluids from surface waters and aquifers, to preserve the geological seal that separates fracture network development from aquifers, and prevent vertical movement of fluids in the annulus (CSSD, p. 4).

Comments

The technology capable of permanently sealing boreholes associated with the oil and gas industry, designed to prevent the upward or downward excursion of chemicals and contaminants in fluid or gaseous phases (e.g., hydrocarbons, metals, methane, ethane, CO2) between geologic formations does not exist. Herein lies a major and unrecognized failing of the CSSD Performance Standards, and of Performance Standard No. 7 in particular. The durability and mechanical properties of gas well sealant materials (primarily cement and steel) are not sufficiently protective of freshwater aquifers and will not last as long as 100 years, much less the thousands of years required – regardless of the number of nested casings used.

Aquifer contamination will persist for centuries, far outlasting the technology for prevention of leakage from wells. Failure of cement sheaths due to shrinkage, debonding, cracking, corrosion, and other mechanisms is well documented throughout gas industry literature (e.g., Rubin**2,3,4,6,7,8**) (Figures 5 and 6). A leading casing manufacturer (TMK IPSCO) states that corrosive fracking chemicals result in a pipe life expectancy of no better than 5 years (Gross, pers. comm.). Short-term analyses and reviews do not adequately address long-term sealant failure and environmental and human health risk, especially following well plugging and abandonment.

Column pipe corrosion in wells, especially those in contact with highly saline waters and/or acid gases, may result in short-term pipe/carbon steel casing failure. [Iron is corrosive in any water with a pH below 9.3.] In turn, this may, with the corrosion and failure of cement sheaths, provide a ready vector for contamination of freshwater aquifers or overlying water bodies. Photo credit: Schnieders, 2009, Water Well Journal.

"Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned. Explanatory mechanisms include channelling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing." Dusseault, Gray and Nawrocki (2000; SPE 64733)

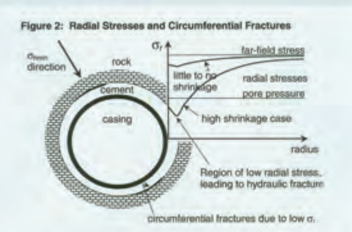
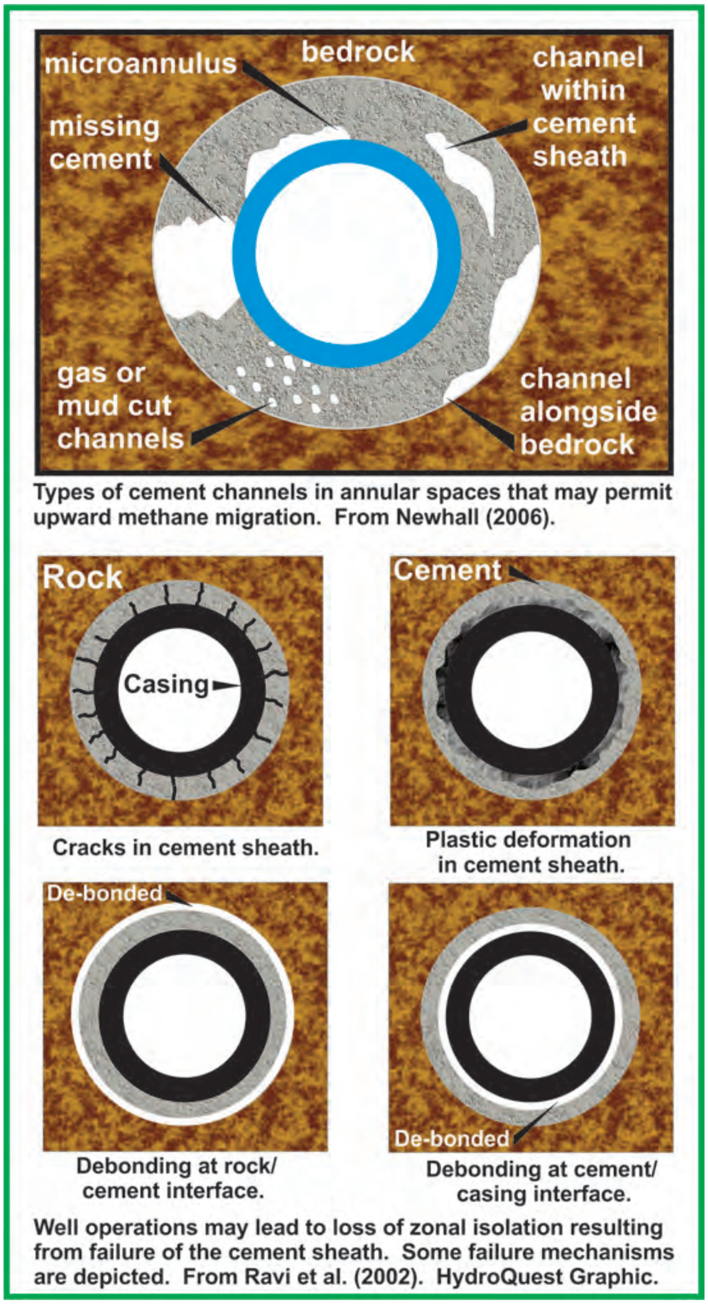


Figure 5. Pipe corrosion in wells and sealant failure mechanisms.

Multi-stage and repeated hydraulic fracturing, cement jobs, and production activities sometimes further degrade the integrity of steel casing (e.g., casing splits) causing it to fail even sooner than it might otherwise under a different use. For example, Cameron et al. (2013) discuss the use of solid-steel expandable liners in the last three years to restore casing damaged by over-pressuring during completion operations in the Marcellus Shale. Cement sheath failure is well recognized as a contributing cause of gas excursions (e.g., Rubin**2,3,4,6,7,8**, McDaniel and Watters, 2014, Nygaard et al., 2014). Well integrity and cement durability problems are significant in the oil and gas industry (e.g., Vignes, 2011).Similarly, failure to effect a quality "*geological seal*" capable of surviving many hundreds of years, or more, jeopardizes future CO2 sequestration projects and people's health (e.g., Pawde and Parekh, 2013). In both cases,



Types of cement channels in annular spaces that may permit upward methane migration. From Newhall (2006).

Well operations may lead to loss of zonal isolation resulting from failure of the cement sheath. Some failure mechanisms are depicted. From Ravi et al. (2002). HydroQuest Graphic.

Figure 6. Cement sheath failure mechanisms.

the cement sealant used to effect zonal isolation of freshwater aquifers will degrade with time and the failure mechanisms discussed above. Testing and analysis of cement durability indicates potential long-term problems, such as increased permeability and porosity and cement deterioration (e.g., Noik and Rivereau, 1999; Krilov et al., 2000; Saint-Marc et al., 2008; Fakhreldin, 2012; Lécolier et al., 2010) which will not "… *preserve the geological seal that separates fracture network development from aquifers, and prevent vertical movement of fluids in the annulus*." Furthermore, cement sheath failure and loss of freshwater zonal isolation results from cyclic stresses experienced while drilling, fracturing, and producing shale gas wells (McDaniel et al., 2014). Failure of well sealant materials in use today is 100 percent assured, it is just a matter of time (with 80 to 100 years being the outside edge of that timeline). For these reasons, the draft CSSD groundwater protection performance standards, which fail to address any of these important issues, cannot protect groundwater quality and public health.

Distinctly lacking from Performance Standard 7 is any mention of time. Aquifer protection is needed well beyond the productive lifetime of gas wells. Also lacking is long-term durability of sealant materials used worldwide at this time. Low-durability wellbore sealant materials currently in use (cement and steel) have design lives of generally less than 100 years and are not capable of ensuring long-term protection of aquifers needed for future generations. Wellbores sealed with cement and steel do not provide reliable, long-term, downhole integrity, that will preclude chemical, gas, and contaminant migration along failed and open wellbores into freshwater aquifers (Figure 7).

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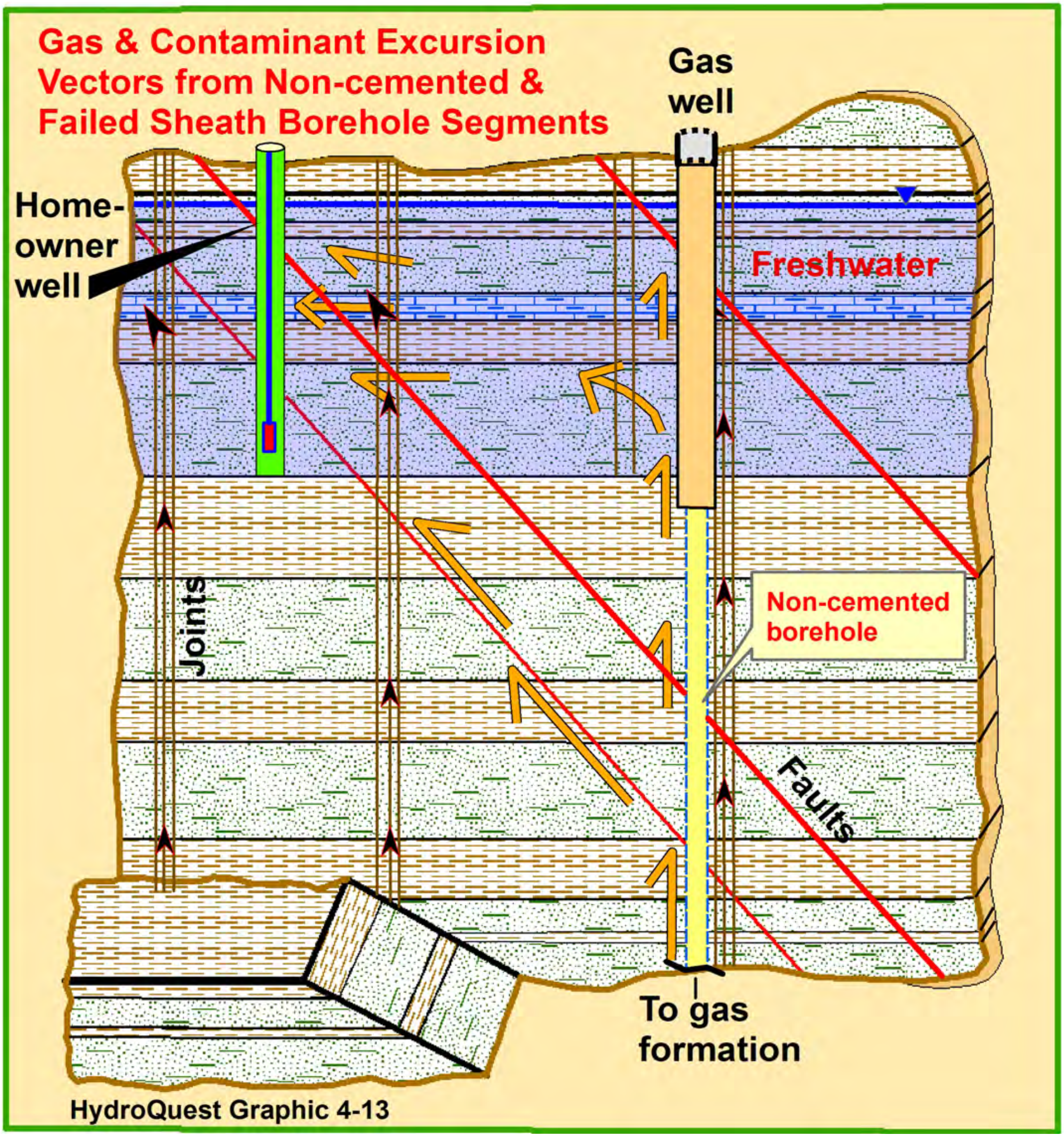

Figure 7. Gas and contaminant excursion vectors from non-cemented and failed sheath borehole segments.

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Rubin3, P.A., April 9, 2011 - Prepared comments on the DRBC draft Natural Gas Development Regulations; Article 7 of Part III – Basin Regulations on behalf of the Delaware Riverkeeper Network, 72 pages with an additional 21 figures.

Rubin4, P.A., January 10, 2012, Aquifer & Karst Protection Considerations in Schoharie and Other New York State Counties (Comments on the NYS High-Volume Hydraulic Fracturing 2011 revised draft SGEIS). Technical report that addresses the need for tracer addition to fracking fluids, vulnerability of karst terrains, limitations of well bore sealant materials, aquifer protection and other issues. In addition, analyses are provided in support of an empirically-based 2,100 foot setback distance from well arrays, the high probability of well bore sealant material failure from earthquake events, and a flood return analysis supporting no well pads within 500-year floodplains. Documentation was provided in support of NYSDEC withdrawing their revised draft SGEIS on gas drilling regulations.

Rubin5, P.A., Jan. 11, 2013, Technical affidavit providing the only hydrologic and empirically based rationale for setback distances from gas well arrays. Provided to the State of New York on behalf of Center for Sustainable Rural Communities of Richmondville, New York to document that the NYS revised hydraulic fracturing regulations A) fail to acknowledge scientific rationale relative to setback distances provided to NYSDEC by HydroQuest both within and after the dSGEIS comment period, B) fail to use "facts and science" to develop setback distances, and C) seek to adopt setback distances irrespective of any empirical scientific basis whatsoever. Fifteen pages plus 5 exhibits.

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Executive Summary

CSSD Performance Standards: Radiation Health and Safety Review

Performance Standards reviewed: Numbers 1, 2, 3, 4, 6, 7, 8, 10, and 14

Marvin Resnikoff, Ph.D.,

The CSSD is silent on the radioactivity in Marcellus shale and how to manage this radioactivity in the form of rock cuttings, liquids and gases. The CSSD is also silent on radon in homes from Marcellus shale and the disposition of radium scale-lined production pipes. The radioactive concentrations in Marcellus shale are far higher than exist in our everyday environment, in the air we breathe and the water we drink. In fact, drillers locate the Marcellus shale horizon by its radioactivity and carbon content.

The radioactivity in Marcellus shale consists of uranium-238 and its radioactive decay products such as radium, radon gas, thorium, bismuth, polonium and lead. When taken into the body, each radionuclide concentrates in different organs. Alpha emitting radionuclides, such as radium, when ingested or inhaled, concentrate in bones and increase the likelihood of leukemia.

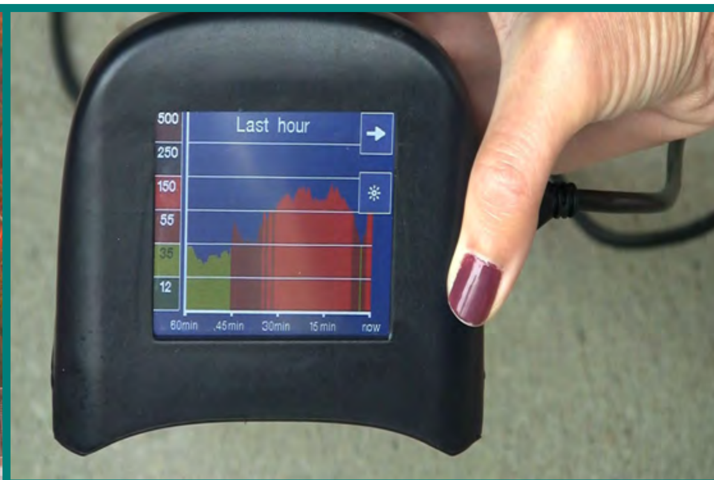
The radioactivity does not disappear once it is brought up to the surface and it cannot be detected through sight or smell; one needs radiation detection instruments. Standard water treatment plants will not satisfactorily remove radium from flowback and brine. The method of treating waste water to remove radioactivity and the term "safe discharge" are not defined by the CSSD. Since radium-226 has a half-life of 1600 years, it is not possible to retain waste water until the radioactivity decays away. The bottom line of this performance requirement of "safe discharge" is that once created, all liquids brought up from Marcellus shale will be radioactive and eventually released to State waterways or groundwater. The CSSD says little about the testing of waste water, discharge water, produced water, flowback water or gases for radioactivity.

The CSSD also does not specify an effective plan for radioactive waste disposal. The CSSD also does not discuss the proper handling of radioactive waste in the pits or the proper disposal of the liner once removed. The CSSD is also silent on the practice, allowed by DEP, of disposing the pit contents on site.

CSSD Performance No. 8 does not include an emergency response to a radioactive spill. The proposed standard does not state who pays for emergency equipment, which should include radiation detection instruments, hazmat suits, and the proper training for onsite workers in case any radioactive brine, or flowback water is released. The CSSD fails to quantify the term "significant" and the time frame to repair a leak.

Over time, radium plates out in production pipes, feed lines and condenser water tanks. CSSD regulations are silent on the disposition of this radioactively coated equipment. The CSSD also fails to discuss the treatment and removal of rock cuttings in the performance standards.

The lack of any attempt to address the radioactivity of Marcellus shale and the handling of radioactive materials produced by shale gas extraction is a glaring oversight by CSSD.



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CSSD Performance Standards: Radiation Health and Safety Review

Marvin Resnikoff, Ph.D.* and CarolAnn Sudia**

These comments on the proposed Performance Standards from the Center for Sustainable Shale Development (CSSD) pertain primarily to radiation health and safety issues. The proposed standards by CSSD are voluntary and will not be protective of gas workers, the public nor the environment. The authors of these comments have had over 20 years experience examining naturally occurring radioactive material (NORM) and technologically enhanced NORM (TENORM) in oil and gas exploration and production in Louisiana, Texas, Kentucky, Mississippi, Pennsylvania, Ohio, West Virginia and New York State. NORM in the Marcellus shale consists of uranium-238 and its radioactive decay products such as radon gas, thorium, bismuth, polonium and lead.

These comments do not directly pertain to the visual, noise or socioeconomic impacts of fracking, nor directly to hazardous chemical releases.

Background

The CSSD proposals fail to recognize that the radioactivity, produced by hydraulic fracturing, will be present in the liquids that are released to Pennsylvania's waterways, will be present in the solids that are transported and deposited in local landfills, and will be present in the radon gas that is inhaled by residents from kitchen stoves at home. When taken into the body, each radionuclide concentrates in different organs. Alpha emitting radionuclides, such as radium, when ingested or inhaled, concentrate in bones and increase the likelihood of leukemia. An alpha particle consists of 2 neutrons and 2 protons. Beta particles or electrons are also emitted by radionuclides in the uranium-238 decay chain. Certain radionuclides in the decay chain emit gamma rays, similar to, but more energetic than, X-rays and expose people when released into the environment or expose workers and people through gamma rays that emanate from gas production pipes. Alpha, beta and gamma radiation alter the DNA structure in humans. When released to the environment, the radionuclides in NORM thereby raise the likelihood of cancer.

The NORM concentrations in Marcellus shale are far higher than exist in our everyday environment, in the air we breathe and the water we drink. In fact, drillers locate the Marcellus shale horizon by its radioactivity and carbon content. The same radioactivity that is used to locate natural gas deposits is also found in hydraulic fracturing waste in the form of drill cuttings, flowback water, produced water, radon gas and radium scale. The radioactivity does not disappear once it is brought up to the surface and it cannot be detected through sight or smell; one needs radiation detection instruments. The performance standards proposed by the CSSD are an attempt to deal with an impossible problem led by an industry blinded to the presence of radioactivity in the natural gas industry.

General Comments

The CSSD is silent on the radioactivity in Marcellus shale and how to manage this radioactivity in the form of rock cuttings, liquids and gases. The CSSD is also silent on radon in homes from Marcellus shale[1] and the disposition of radium scale-lined production pipes. The CSSD attempts a number of improvements in their performance standards proposal. The CSSD proposes a goal for recycling 90% of all flowback and produced water, and requires the use of double-lined pits; In our opinion, the CSSD's proposed standards do not go far enough in protecting water supplies and the health and safety of the general public, as discussed below.

Performance Standard No. 1

> Operators shall maintain zero discharge of wastewater (including drilling, flowback and produced waters) to Waters of the Commonwealth of Pennsylvania and other states until such time as CSSD adopts a standard for treating shale wastewater to allow for safe discharge.[2]

For each well, hydraulic fracturing operations use a large quantity of water, three to five million gallons. Drilling fluid constitutes 95% water plus chemicals

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1 Resnikoff, 2012

2 Center for Sustainable Shale Development (CSSD), 2013

and proppants, to maintain cracks in the shale formations. Ten to 40 percent of the drilling fluid is returned to the surface in the first few days after hydraulic fracturing ceases (flowback). When a gas well goes into production, lesser amounts of water are returned and separated from natural gas at the wellhead (brine). Radioactive concentrations and total dissolved solids in brine are high; radium-226 concentrations can be as high as 15,000 pCi/L, according to the NYSDEC.[3] This can be compared to environmental sources of water, generally about 0.9pCi/L.[4] The CSSD proposal states that flowback and brine will be retained until CSSD adopts "a standard for treating shale wastewater to allow for safe discharge." But the method of treating waste water to remove radioactivity and the term "safe discharge" are not defined by the CSSD. Since radium-226 has a half-life of 1600 years, it is not possible to retain waste water until the radioactivity decays away. The bottom line of this performance requirement of "safe discharge" is that once created, all liquids brought up from Marcellus shale will be radioactive and released to State waterways, and that means radioactive materials, as allowed by law, will end up in our waterways. Any release of radioactively-contaminated wastewater to the environment will raise background radioactive concentrations and cause an increase of cancers. In the human body, radium behaves like calcium, and will concentrate in bones, where red marrow is produced, and can increase the likelihood of leukemia.[5]

To be clear about this, all radium-226 brought to the surface, will either be diluted and released to surface water; this is what CSSD means by "safe discharge," or in ways undefined, radium-226 will be removed from flowback and brine, and disposed in some manner. Or, liquids will be disposed in deep wells, though the number of deep wells is limited and more expensive. Since "safe discharge" is not defined, we can guess what "safe discharge" may mean: radioactive concentration limits to drinking water: Alpha - 15 pCi/L, Ra-226 and Ra-228 (combined) - 5 pCi/L and Uranium - 30 micrograms/L.[6] The radiation dose limit in drinking water is 4 mrems/yr due to beta and photon radiation. Chapter 95 of Pennsylvania Code 25 discusses the amount of total dissolved solids (500 mg/L), chlorides (250 mg/L), barium (10 mg/L) and strontium (10 mg/L) that are allowed to be discharged each month.[7] While it is positive that the Pennsylvania DEP places a limit on the concentrations of chemicals that are allowed to be discharged monthly, the regulation fails to place a limit on the total amount of radionuclides that are allowed to be discharged monthly. Without a limit, all radium-226 brought to the surface will enter surface streams, be separated and disposed in undefined ways, or go into deep wells. The CSSD fails to address this significant issue in any serious way.

In addition to the definition of "safe discharge" the CSSD does not discuss the method of testing for "safe discharge," namely the need for sending flowback water and brines to an EPA-certified laboratory. At present, liquids are sent to a water treatment plant (POTW) or centralized treatment facility.[8] If the gas driller does not test for and label radioactivity in the water, the water treatment plant will not be able to determine if they have removed the radioactivity; if the POTW does not properly test for radioactivity, it cannot determine that the discharge requirements are met. The omission of radioactive testing regulations does not mean that radioactivity doesn't exist; it means that the radioactivity that is being produced from hydraulic fracturing wells cannot be detected. Again, the CSSD fails to address this issue in any serious way.

It is doubtful that standard water treatment plants will satisfactorily remove radium from flowback and brine. In particulate form, radium will become part of filter sludges which must be properly disposed, in a licensed radioactive waste facility. The CSSD does not have an effective plan for radioactive waste disposal. This waste consists of contaminated sludges and filters, including sludge and sediments that remain in a storage pond. In addition to radionuclides, the CSSD does not address the testing of hydrocarbons, arsenic, mercury, and TDS in aquifers and surface streams before well drilling commences, so that a baseline of background concentration is established. Without

3 NYSDEC, rdsgeis, app 13
4 Longtin, 1988
5 NAS, BEIR V rpt, increase bone cancer
6 DEP, 25 Pa. Code § 109

7 DEP, 25 Pa. Code § 95
8 A centralized waste treatment (CWT) facility accepts drilling liquids that are trucked in and partially removes solids and some chemical contaminants; the treated liquids are often returned to drillers for reuse, or released to streams and rivers. Radionuclides, such as radium, that are in solution, are not removed. Several centralized waste treatment facilities are located in PA, including Advanced Waste Services (New Castle, PA) and Waste Treatment Corporation (Warren, PA). CWT's are similar to POTW,s which accept all local waste water and remove solids.

this the CSSD cannot know whether gas well drilling and production have contaminated surface waters or aquifers.

Performance Standard No. 2

> Operators must recycle a minimum of 90% of the flowback and produced water, by volume, from its wells in all core operating areas in which an Operator is a net water user.[9]

Even if 100% of drilling fluid of flowback and produced water were recycled, additional water would be required to drill additional wells. While RWMA favors the concept of recycling 90% of produced and flowback water, the fact is only 10-40% of the water used for hydraulic fracturing is returned as produced or flowback water[10]. The natural gas industry would remain a major user of water. A standard horizontal drilling well uses "between 3 and 5 million gallons of water per frack. This means that even if the operator was able to exceed the CSSD's minimum standard and recycle 100% of produced and flowback waters from the original 3,000,000 gallon fracture, s/he would still have to find between 1.8 and 2.7 million[11] gallons of freshwater to perform the next fracture. These numbers increase to 1.92 and 2.73 million gallons of freshwater that have to be externally sourced even if the operator only meets the minimum standard set forth by the CSSD. The CSSD failed to consider where the additional millions of gallons of water would come from and how this additional withdrawn water might impact the local environment.

The CSSD also fails to explain how operators are required to recycle the flowback water. When produced and flowback water is reused, the concentration of radioactivity within the water increases. The water that is used to break shale rock comes into contact with Uranium and Thorium, parent nuclides of Ra-226 and Ra-228 respectively. Radium is highly soluble under the temperature and pressure conditions below ground. This has been an ongoing process for millions of years. The recycling of fracking waste water will increase the radioactivity of the water as it continues to be recycled. The radioactive waste water will have to be tested to determine the level of radiation and then stored in special containers between hydraulic fractures so that radionuclides do not travel into local waterways. The decay products of radium-226, particularly bismuth-214, are strong gamma emitters, making the recycled drilling fluid an occupational hazard. Performance standard No. 2 does not even discuss the issue. Once the water can no longer be recycled, its increased radioactivity will be more difficult and costly to treat and will reduce the likelihood of the recycled water to be properly treated.

Standard water treatment facilities are not capable of treating flowback and produced water to safe levels of radioactivity. The CSSD says little about the testing of waste water, discharge water, produced water or flowback water for radioactivity or the need to properly treat or remove radioactive material so it cannot adversely impact the environment or human health. If radioactivity is removed, the CSSD says nothing about its ultimate disposition.

9 CSSD, 2013
10 Brzycki
11 Calculation Table can be found in Figure 1

Additional Gallons of Water Needed with 100% and 90% Recycled, Produced and Flowback Water.

Original H_20 (gallons)	Percent that comes back as flowback and produced water	Percent of flowback and produced water recycled	Total gallons of water recycled	Fresh water needed for subsequent fracture (gallons)
3,000,000	40%	100%	1,200,000	1,800,000
3,000,000	10%	100%	300,000	2,700,000
5,000,000	40%	100%	2,000,000	3,000,000
5,000,000	10%	100%	500,000	4,500,000
3,000,000	40%	90%	1,080,000	1,920,000
3,000,000	10%	90%	270,000	2,730,000
5,000,000	40%	90%	1,800,000	3,200,000
5,000,000	10%	90%	450,000	4,550,000

Figure 1

Performance Standard No. 3

> Any new pits designed shall be double-lined and equipped with leak detection.[12]

Current holding pits are not properly lined. There have been a number of cases where pits have leaked due to improper lining.[13] The CSSD does not appropriately address the issues that arise from storage of wastes in these pits and pit linings.

The CSSD fails to specify what materials will be used to double line the pits. The lining material can greatly impact the permeability. Fracking waste water contains radionuclides, such as Bi-214, that emit gamma rays. Soil and water are able to safely block gamma radiation however gamma emitters within the radioactive fluids (such as Bi-214) may leach out of improperly lined pits and contaminate nearby waterways.

The CSSD also fails to report what will happen once a leak is detected. The CSSD fails to list the protocol needed so that operators and officials understand the necessary steps to take in order to reduce the impact of a leak once it occurs and the best way to remediate a spill after it happens. Proper procedures to remediate a radioactive spill such as testing soil and water for contamination and what to do if contamination is found, are simply not discussed.

The CSSD says nothing about a performance bond, sufficient to cover remediation costs.

The CSSD does not discuss the proper handling of radioactive waste in the pits or the proper disposal of the liner once removed. Chapter 78 of Pennsylvania Code 25 discusses some methods of pit content disposal: "If a liner becomes torn or otherwise loses its integrity, the pit shall be managed to prevent the pit contents from leaking from the pit. If repair of the liner or construction of another temporary pit is not practical or possible, the pit contents shall be removed and disposed at an approved waste disposal facility or disposed on the well site."[14] While Pennsylvania's DEP recognizes compromised pits, the many shortcomings in the manner of disposal of waste water suggested by the DEP are not addressed by the CSSD and the CSSD says nothing about emergency measures.

The CSSD does not state how the contents of the pit should be disposed. The CSSD is silent on the practice, allowed by DEP, of disposing the pit contents on site. This option is often the cheapest which means that many operators have buried their untreated radioactive contaminated waste onsite, where it can easily leach out and contaminate local streams and environments. Simply requiring a double liner, as CSSD performance standard states, does not speak to the long-term safety of leaving contaminated materials onsite.[15] Further, if a landowner were to exhume this buried material, by building a structure with a basement, the waste would represent a safety hazard and a liability to the landowner and future residents. The waste would diminish the land value. We are not lawyers, but we can foresee major nuisance lawsuits.

> By March 20, 2015, operators […] shall contain drilling fluid and flowback water in a closed loop system at the well pad, eliminating the use of pits for all wells.[16]

In order for a closed loop system to work, drilling fluids must first be separated from rock cuttings in a shaker. The CSSD does not specify what will happen to the solid and liquid phases of this radioactive solution, except that the liquids would be in a closed loop system. It can be assumed that the liquid will be reused in another hydraulic fracture which, as mentioned above, will only increase the concentration of radioactive contaminants in the solution. Solids are often used to create new access roads or well pads on future hydraulic fracturing sites.[17] The effect of placing radioactive solids, which contain radium-226, is to raise the background radiation dose rate; the gamma emissions are like an X-ray machine that cannot be turned off.

Standard No. 3 says nothing about the radioactive concentrations in leftover solids. These solids would increase the radiation exposure to workers exposed to the material and could eventually make its way to water supplies where it would affect a much larger population.

Standard No. 3 does not call for testing of solids for radioactivity and if they are found to be radioactive, for the need to properly disposed of solids in a facility that is equipped to handle radioactive waste.

Standard No. 3 does not apply to solids that are disposed before March 20, 2014.

12 CSSD, 2013

13 Stag, S. (n.d.). Retrieved from http://frackingofamerica.com/

14 DEP, 25 Pa. Code § 78

15 We have surveyed sites in PA where the driller simply covered the former waste pond, allowing contaminated waste to remain on site.

16 CSSD, 2013

17 Smith-Heavenrich, 2008

Performance Standard No. 4

> Operators shall ensure […] that new impoundments are double-lined with an impermeable material, equipped with leak detection and take measures to reasonably prevent hazards to wildlife. Total hydrocarbons should be substantially removed.[18]

While Performance Standard 4 is interested in the removal of hydrocarbons the CSSD neglects to recommend the removal of radionuclides like radium from waste water.. Radium, a decay product of uranium, is a common element in fracking waste water and due to its shared properties with calcium, once ingested or inhaled, concentrates in the bones of exposed individuals and increases the likelihood of bone cancer and leukemia.[19]

The CSSD is vague when discussing key items in this performance standard. The type of "impermeable material" in pit liners is not defined, leaving one to question exactly to what the material will be impermeable.

Additionally, the CSSD states that this performance will "*reasonably* prevent hazards to wildlife" and that "hydrocarbons *should* be *substantially* removed". This terminology is imprecise; owners and operators have no guidance on the levels to which wildlife needs to be protected from hazards and exactly what percentage of hydrocarbons should be removed from the waste water. The hazards to wildlife will differ once radioactive material is included in the composition of wastewater. The combined effects of hydrocarbons and radioactive material are not discussed in the CSSD's analysis of potential hazards to wildlife.

Performance Standard No. 6

> Operators shall develop and implement a plan for monitoring existing water sources […] within a 2,500 foot radius of the wellhead […] and demonstrate that water quality and chem*is*try measured during a pre-drilling assessment are not impacted by operations.[20]

Before drilling, water testing is important in order to establish a baseline including for parameters such as hydrocarbons, arsenic, mercury, TDS and radium. This allows operators, regulators and the public to know the impact of well drilling and gas production on any nearby water sources. However, the radius provided for testing around water sources is not large enough to acquire the most comprehensive understanding of the effects of well drilling operations. In addition, the CSSD fails to identify specific parameters for pre-drilling assessment in order to assure uniformity of testing across the industry.

In our experience, the distance of 2,500 feet, from a water source is not sufficient. Members of the RWMA team have witnessed the effect on personal drinking wells over a mile away from a fracking site; these residential and farming wells were contaminated by drilling fluids from the increased underground pressure during hydraulic fracturing.

The basic problem is the following. After vertical bore holes are drilled, drillers construct concrete casings. But these concrete drill casings are weakest at the aquifer horizons. These residential and farming wells were contaminated by fluids from drilling and operations of nearby gas wells. Drillers sometimes replace the contaminated source of water for drinking, but affected residents have developed rashes when taking showers.

Chapter 78 of Pennsylvania code 25 discusses the potential effects that a hydraulic fracturing site might have on local water sources and the responsibility of the operator to return the water sources to their original condition. That is, Chapter 78 recognizes that water wells could be contaminated. Chapter 78 of Pennsylvania Code 25 states that "A restored or replaced water supply, at a minimum, must be as reliable as the previous water supply, be as permanent as the previous water supply, not require excessive maintenance, provide the water user with as much control and accessibility as exercised over the previous water supply" These standards can only be held if there is a baseline taken of the site before groundbreaking commences and if the proper elements were tested for prior to natural gas production. Radium is not often tested for when other baseline tests on local water bodies occur. This means that if radioactive waste water is discharged into a water source from a natural gas well and a radioactive baseline was not obtained, the owner or operator of the well will not be held accountable to restore the water source to baseline concentrations. The CSSD performance standards do not include any baseline testing of radium, uranium, thorium and any other radionuclide that could be present in all shale formations, including Marcellus and underlying Utica shale.

18 CSSD, 2013
19 NAS, BEIR V, p. 307.
20 CSSD, 2013

The CSSD performance standards also do not indicate a time frame for when the water sources will be returned to their original state so that victims of the compromised water source will only have to suffer from the negative retributions of the natural gas industry for a brief period. This lack of time frame allows people to continue to be affected by the consequences of the natural gas industry for an undetermined amount of time. If radium or another radionuclide is present in the water, continued exposure will increase a person's likelihood of developing cancer from their exposure.

Performance Standard No. 7

> Operators shall design and install casing and cement to completely isolate the well and all drilling and produced fluids from surface waters and aquifers to preserve the geological seal that separates fracture network development from aquifers and prevent vertical movement of fluids in the annulus.[21]

This performance standard is difficult to satisfy. Many wells that were cased and sealed with cement have leaked. In 2010, inspectors documented that out of 1609 wells that were drilled and fracked, 111 of them leaked and in 2012 out of 1,014 wells that were drilled and fracked, 67 of them leaked. This equates to a 6.9% and 6.6% rate of failure respectively. The failure rate of wells increases to 30-50% as the wells age.[22] These numbers represent wells that leaked at the well head, not those that "sprouted up in stream beds, water wells, or ponds often 2,000 feet away from the well site." Despite this there is no discussion in the CSSD performance standards of the need for leak detectors to be able to immediately identify when there is a problem that requires response nor does the CSSD discuss the repair of breaks in casing in order to prevent methane and fracking fluids from leaking into nearby groundwater. An environmental health and safety plan should be onsite and readily available in case a leak is discovered.

The CSSD also does not consider in any regard the issue of mapping wells in the drilling areas, plugged and unplugged, for identifying, preventing and/or reacting to problems. Scientific American reports a case in Texas where after one well was plugged, the additional pressure was released in three nearby wells causing them to spew waste water like artesian wells.[23] The affected landowners were responsible for the cost of cleaning up the damage that was caused by the once dormant wells on their property. Requiring a map of nearby plugged and unplugged wells would allow the operator to understand the surrounding geology and ensure a proper spacing between wells so that capped pressure from one well does not inadvertently negatively affect a nearby well.

Performance Standard No. 8

> In preparation for any spill or release event, Operators shall prior to commencement of drilling, develop and implement an emergency response plan, ensure local responders have appropriate training in the event of an emergency and work with the local governing body, in which the well is located, to verify that local responders have appropriate equipment to respond to an emergency at a well.[24]

Planning should take place before an emergency, not when the emergency occurs. CSSD Performance No. 8 does not include an emergency response to a radioactive spill. The proposed standard does not state who pays for emergency equipment, which should include radiation detection instruments, hazmat suits, and the proper training for onsite workers in case any radioactive brine, or flowback water is released. Training and equipment should be paid for by operators. Without the proper safety plan set in place, a radioactive spill will contaminate local environments and expose workers to radioactivity.

Performance Standard No. 10

> Flaring may not be used for more than 14-days on any development well (for the life of the well). Flaring may not be used for more than 30-days on any exploratory or extension wells (for the life of the well), including initial or recompletion production tests, unless operation requires an extension. If flaring continues beyond 30-days for an exploratory or extension well, Operators must document the extent of additional flaring and reasons requiring flaring beyond the 30-days.[25]

The CSSD is silent on the presence of radon in natural gas. During flaring, radon, an inert, radioactive gas will be released. The inhalation of radon increases the likelihood of lung cancer. While we have some

21 CSSD, 2013
22 Nikiforuk, 2013
23 Nikiforuk, 2013
24 CSSD, 2013
25 CSSD, 2013

concern for workers and local residents near the well site when flaring, we have great concern about the release of radon from kitchen stoves in metropolitan areas near Marcellus shale. While we recognize that downstream use of natural gas is not a performance issue and does not relate directly to hydraulic fracturing per se, it is related to the distribution of natural gas and the location of the Marcellus formation near metropolitan areas. Perhaps for this reason, the CSSD is silent on the issue of radon in natural gas.

Performance Standard No. 14

> Once significant leaks are detected, they are required to be repaired in a timely manner.[26]

This statement is vague. The CSSD fails to quantify the term "significant" and the time frame to repair the leak. The CSSD need to specify the time to repair a leak once it is discovered and should include how many gallons of leakage, and how many cubic feet of gas would be considered "significant." In fact, any leak, significant or not, should be repaired. In a ProPublica review of wastewater wells between 2007 and 2010, of the 220,000 wells inspected, more than 7,000 wells showed signs of leakage.[27] The data shows that most of the wells were patched within 6-months of being discovered however because (according to DEP regulations) there can be up to 5-years between inspections,[28] it can take a long time for leaks to be detected by regulators. This means that a leaking well has the potential to leak radioactivity up to five years before being discovered. The CSSD failed to recommend a stronger regulatory framework for the time to test wells for leaks. If leaks are found early they are less likely to leak large quantities of radioactive waste into near by water sources.

Additional Comments

In addition to flowback water and brine, CSSD regulations are silent on the disposition of production pipes, feed lines and condenser water tanks. In our experience, it is not unusual to remove production pipes after 5 years of well production and to have these pipes internally coated with radium-contaminated (barium sulfate compound) scale. The New York State generic GEIS[29] states that "NYSDOH will require the well operator to obtain a radioactive materials license when exposure rate measurements on the outside of contaminated equipment exceed 50 microR/hr." In our experience with gas pipes in Texas, after 15 years production, more than 50% of the pipes will have direct gamma dose rates greater than 50 microR/hr. According to our calculations using Microshield, and a standard 3 to 1 ratio of radium-226 to radium-228, pipes that emit gamma equal to 50 microR/hr will have radium-226 and radium-228 concentrations in scale that exceed 1300 pCi/g and 435 pCi/g, respectively. These concentrations can be compared to EPA cleanup standards of 5 pCi/g on the top 15 cm of land, and 15 pCi/g below 15 cm. If contaminated pipes are released for general unrestricted use, they can be used for corrals, playground equipment, etc. If radium at these concentrations is released to the environment, the respective radiation doses to children and the general public will be high. Pennsylvania, West Virginia and Ohio have not produced an EIS that evaluates the impact to individuals and the general population of releasing contaminated pipes for general use.

The CSSD also fails to discuss the treatment and removal of rock cuttings in the performance standards. The NYSDEC has measured radium-226 concentrations as high as 206 pCi/g from rock cuttings going to the Allied landfill in Niagara County, NY.[30] The CSSD does not discuss the testing of rock cuttings for radioactivity before they are sent to landfills for disposal. If the rock cuttings are determined to be radioactive, they should be sent to a proper facility where they can be disposed of without harming landfill workers, and local residents and waterways that the radioactive materials could leach into.

The major overall concern RWMA has with the proposed CSSD's Performance Standards is the lack of a mention of radioactivity in the document. In our opinion, this is a major failure. There is a limited amount of information present in regulations that links radioactivity to the natural gas industry. This is a problem that needs to be addressed at all levels of the government and the natural gas industry who fail to regulate radioactive discharge from natural gas waste because of a lack of testing for radioactivity. The Center for Sustainable Shale Development has not seriously considered the radioactivity in Marcellus shale liquids, solids and radon. The proposed standards will not protect industry workers and Pennsylvania residents and those in other states receiving waste from Pennsylvania.

26 CSSD, 2013
27 Lustgarten, 2012
28 PA Code 25, Chap 78
29 Rdsgeis, p. 5-142 and p. 6-205.
30 Allied landfill reference

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Executive Summary

CSSD Performance Standards: Groundwater Quality and Monitoring Review

Performance Standards reviewed: Numbers 5 and 6

Tom Myers, Ph.D.

Why Standards Number Five (Area of Review around a Gas Well) and Six (Groundwater Quality Monitoring) Fail

Standard Number 5 requires the operator establish an area of review (AOR) that is insufficient to protect water resources. The AOR is established around a proposed gas well to characterize the subsurface. This is supposed to provide information that would demonstrate the presence of an adequate confining layer to prevent the adverse migration of hydraulic fracturing (HF) fluids and to identify the presence of abandoned wells and faults but many critical factors are ignored.

- **The standard fails because the AOR is much too small and may be defined by individual horizontal well bores.** The AOR only must include the area above the predicted length of fractures from the well, without regard to the accuracy of those predictions or the fact that fluids transport occurs along pathways other than HF-induced fractures.
- **The standard fails because it does not establish criteria for assuring the integrity of the geologic layers above the shale to prevent adverse movement of HF fluid.** The operator is not required to determine the permeability of the layers above the shale, which can be very heterogeneous -- meaning the permeability varies depending on location and on distance from a natural fracture.
- **The standard does not require specific geophysical tests to identify the location of faults and fractures** but rather leaves that up to the operator.
- **The standard fails because the operator is required to identify nearby abandoned wells but the operator may rely on maps prepared by the state** to identify abandoned wells even though this mapping is very incomplete.

Standard Number 6 establishes a groundwater quality monitoring plan that is inadequate to accurately monitor for water contamination. A groundwater monitoring plan is established to monitor for water contamination and requires that the company implement a plan for further investigation of potential contamination as well as a plan for corrective action if there is a positive link between the contamination and fracking. This is supposed to track and address contamination caused by shale gas extraction but both the monitoring and required response to a “possible link” are inadequate to accurately identify contamination or provide a remedy.

- **The standard fails because it relies on existing wells rather than dedicated monitoring wells.** Domestic wells, and other production wells, are designed to maximize water production, which usually requires long screens or open intervals; they are not designed to sample the most critical portions of an aquifer. The concentration of any contaminant would fluctuate due to dilution because they are pumped at frequent and irregular periods. Dedicated monitoring wells are more reliable and accurate because would be placed at optimal locations and screened at the proper depths to detect the movement of a plume. However, this is not recommended by CSSD.
- **The standard fails because the requirement to monitor wells only within 2500 feet of the vertical bore may be grossly insufficient.** This distance is arbitrary because it does not consider the potential flowpaths from either surface spills or leaks or from deep in the wellbore or the shale, which could include faults, fractures, and flow along the bedding plane of sedimentary rocks.
- **The standard fails because the one-year time period for monitoring is grossly too short** and it does not account for the potential travel time of pollutants in groundwater, which studies have indicated could range from very short to centuries depending on the details of the flowpath.
- Ultimately, the standard is insufficient because it fails to require the operator to complete a conceptual flow and transport model which would be used to establish the location of dedicated monitoring wells, to determine the distance from the HF operation which should be sampled, and the duration of time and frequency of sampling.
- The standard does not indicate what would be a positive link between fracking and contaminations. It does not even acknowledge that the presence of HF fluid in a well or how much of an increase in concentration is a positive link between fracking and contamination, a major flaw in the ability to reasonably apply this standard to discern if there has been contamination.

CSSD Performance Standards: Groundwater Quality and Monitoring Review

Tom Myers, Ph.D.*

Background

The Center for Sustainable Shale Development (CSSD) has issued water performance standards with the goal of "zero contamination of fresh groundwater and surface waters." This technical memorandum considers performance standards 5 and 6, those which pertain specifically to the preservation of groundwater quality and its monitoring. Throughout this review, the Standards document is referred to as "Standards" and a support document intended to apply to auditors is referred to as "Guidance for Auditors." Other documents available on the CSSD website were also reviewed and two comments are addressed at the end of this section.

The Standards claim to apply to "fresh groundwater" and define that as "water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials." By including all saturated pores beneath the ground surface (subsurface), this definition essentially includes all aquifers. However, the use of the term "fresh" is ambiguous and is assumed to refer to drinking water sources. The Standards are not as strong as the Environmental Protection Agency's definition of an underground source of drinking water (40 CFR 144.3), which defines "fresh" as any groundwater with total dissolved solids (TDS) less than 10,000 mg/l with some exceptions which should not apply because with a growing population and increasing stresses on groundwater resources, society may use groundwater in the future that would be less feasible today. As written, these standards would likely not protect groundwater even with TDS less than 10,000 mg/l if the industry found the groundwater was not currently being used, such as they did at Pavillion WY where they essentially fracked an underground source of drinking water (DiGuilio et al. 2011). In other words, these standards would not have prevented the contamination that has occurred at Pavillion.

Hydraulic fracturing (HF) to develop natural gas (NG) is the most recent development to potentially affect water resources for time periods that are orders of magnitude longer than the time during which the development will benefit anyone. Other obvious examples include the mining industry creating or even planning developments that will require drainage be captured and treated in perpetuity, generally defined as longer than 500 years, and the creation of waste disposal sites that will leach toxic constituents into the ground essentially forever. HF fits with these other examples because research concerning long-term transport indicates that HF could cause contaminants to reach drinking water supplies in the 1000-year time span (Gassiat et al. 2013; Myers 2012, in review; Warner et al 2012a). Two big problems with HF is that transport could occur much faster (Myers 2012, in review) and there is nothing that can be done to prevent contaminants reaching shallow groundwater if HF development creates a pathway (Gassiat et al. 2013a). There is nothing in these standards which addresses the intergenerational equity issues raised by potential long-term contamination (Gleeson et al. 2012). However, in contrast to Gleeson et al, this review takes a 1000-year view on preventing contamination from HF. This time period is selected as a balance between transport times and the attenuation of HF chemicals, which would tend to limit contamination.

The review presented herein does not distinguish between contamination by gas or by HF fluid. Contamination of water wells by gas caused by HF has been documented several times (Jackson et al. 2013a; Osborn et al. 2011a, 2011b) although those studies have been questioned (Molofsky et al. 2013).

Peer-reviewed literature has never documented injected HF fluid reaching shallow groundwater from the targeted formation, but there have been potential such occurrences (DiGiulio et al. 2011; EPA 1987). The movement of Marcellus brine to the surface has also been suggested although the time frame for such transport has not been established (Llewellyn 2014; Warner et al. 2012a). There has also been contamination of surface waters by both gas and HF fluid caused by leaks and spills nearer the shallow groundwater (Vengosh et al. 2014)

If development proceeds as speculated by the NG industry, large areas will have well pads spaced as

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little as a mile apart. Horizontal well bores may parallel each other and be only a couple hundred meters apart. This would create a relatively high density of horizontal well bores. The NG industry, however has failed to implement or even propose a groundwater monitoring system at any location that could detect the movement of contaminants from the shale or from leaks in the well bores.

Groundwater monitoring does not prevent contamination and therefore must be accompanied by an action plan to prevent detected contamination from spreading. Otherwise, monitoring is just documenting the degradation. A mitigation plan would include a means to intercept the contaminant before it reaches shallow groundwater or surface sources thereby preventing those sources from being contaminated. Replacing a water source with water from somewhere else is not an acceptable plan because it just exports the degradation to wherever the water is imported from. However, preventing the spread of a substantial contaminant plume moving along a pathway could be a costly proposition, if it is even technologically feasible. There is no substitute for doing HF correctly the first time, which here would be defined as all fluids, gas and liquid, remaining beneath the layer identified as a "confining layer."

CSSD would select firms to audit HF operators to determine whether their operations meet these proposed standards. CSSD also wrote an Accreditation and Qualifications document that specify the qualifications CSSD will use to select auditor firms. Basically, the auditors are not required to have anyone with qualifications to consider the issues raised by the performance standards reviewed herein. The Qualifications document requires that auditors have experience and training in the oil and gas industry, effectively meaning oil and gas engineers, but those are not adequate qualifications for considering the potential for contaminant transport in a fault or designing groundwater monitoring systems. Unless CSSD requires the auditor to have experts in geology/hydrogeology to supplement the required engineers, the audits will not be useful. Additionally, requiring the auditor to essentially be oil and gas industry experts will assure they are drawn directly from the industry. This will raise questions of bias because oil and gas experts are more likely to accept assurances regarding apparent departures from the standard from their colleagues in the industry over concerns raised by the public, even from scientific experts who are part of the public.

Finally, the Accreditation document essentially requires the auditor to maintain complete secrecy. They may not release data and possibly not even detailed analyses of the operator's plans. By requiring them to be oil and gas experts and by not allowing any public review of the data or analyses, the public has no assurance that the audits will be unbiased.

Performance Standard 5

> Operators shall establish an Area of Review (AOR), prior to drilling a well, which encompasses both the vertical and horizontal legs of the planned well. Within the AOR, the Operator must conduct a comprehensive characterization of subsurface geology, including a risk analysis that demonstrates the presence of an adequate confining layer above the production zone that will prevent adverse migration of hydraulic fracturing fluids. As part of the risk analysis, and before proceeding with hydraulic fracturing, the Operator must also conduct a thorough investigation of any active or abandoned wellbores within such area of review or other geologic vulnerabilities (e.g., faults) that penetrate the confining layer and adequately address identified risks.[1]

This standard pertains to requirements for the operator to consider the geology of the site to be developed. Specifically, the standard pertains to the potential for HF fluids injected into the shale to migrate to shallow groundwater or to the surface. The potential movement of HF fluid to water resources from the production zone is the one aspect of HF that simply cannot be engineered out of the process (Gassiat et al. 2013). In other words, the process of injecting fluids into and fracturing the shale causes the potential pollution problem.

Background

The NG industry initially assumed that fluids cannot flow from the shale to surface because the intervening one to four kilometers of sedimentary rock would isolate the process (Engelder 2012) and, even if there was a pathway there was a perceived lack of pressure gradient to drive the flow (NYSDEC 2011). Observations and theoretical considerations have shown these assumptions to be dubious. In the Marcellus Shale re-

1 Center for Sustainable Shale Development (CSSD). 2013. Performance Standards. Pittsburgh PA: CSSD.

gion, studies have documented the movement of gas from depth to the near surface (Jackson et al. 2013a; Osborn et al. 2011a and b). These studies did not document the pathway but they did indicate that gas traveled from depth, either from the well or the shale, to the surface and that a pathway exists between the shale and the surface. A recent study has suggested that gas found in shallow water wells must result from gas leaks on the well bore rather than from release from the shale itself (Darrah et al 2014), but this conclusion depends on a dubious claim that buoyant gas moving from the shale through a fracture to shallow groundwater in weeks undergoes the same changes as dissolved gas migrating over geologic time. Another study found that gas tracers released during HF were found at production wells 750 feet away from the source within days (Hammock et al 2014). They also found possible evidence of gas migration to a sandstone layer 3000 feet above the Marcellus shale (Id., Figure 33). A study based on conditions found at the site used in Hammock et al estimated that gas can flow from a leak to a well 170 m away ranging from 89 days to 17 years depending on conditions (Zhang et al 2014); this study considered gas flow through a sandstone rock matrix, not through fractures which the authors indicate could cause the gas to move much quicker.

Similarly finding places to sequester gas where there are no pathways to the surface is the largest obstacle to carbon dioxide sequestration, and the process for it being released is similar to that for methane escaping the newly permeable shale and migrating to the surface (Cihan et al. 2013, Hassan and Jiang 2012; Celia and Nordbotten 2009; Yamamoto et al. 2009).

Other studies have documented that brine originating in the Marcellus Shale has reached shallow groundwater (Warner et al. 2012a and b). Based on isotope analysis, Warner et al. (2012a) linked water found in shallow groundwater in Pennsylvania to Marcellus brine. They write that the "geochemical and isotopic data of the flow back water clearly mirror the composition of brine and mainly reflect dilution of the Marcellus Formation water with [fracking fluid]" (Warner et al. 2012b, references omitted). Llewellyn (2014) presented similar results. Engelder et al (2014) and Engelder (2012) disputes that this finding suggests there is a risk of fracking fluid reaching the surface, with the primary argument being that fracking fluid would imbibe into the capillary pore spaces of the dry shale. Warner et al. (2012b) question that the shale is dry by noting that the presence of "a significant percentage" of brine in the return flow indicates that substantial flow can discharge from the shale. Haluszczak et al. (2012, abstract) also found that "[f]lowback waters from HF of Marcellus wells resemble brines produced from conventional gas wells that tap into other Paleozoic formations in the region." The "increased salt concentration in flowback is not mainly caused by dissolution of salt or other minerals in rock units" and "flowback water represent a mixture of injection waters with highly concentrated *in situ* brines similar to those in the other formations" (Id., bold emphasis added). Rowan et al (2014), publishing in the industry-based AAPG Journal, documented isotopically and geochemically the transition that flowback makes from initially being returning HF fluid to later being formation fluid, or brine. Chapman et al (2012) found that strontium ratios in Marcellus brine were excellent tracer of that brine because of the large amount of brine released during fracking. There must be enough free water in the shale to mix with the HF fluid because even fracturing will not release water from capillary pore spaces fast enough to be included in short-term flowback.

Both (Engelder 2012; Warner et al. 2012a and b) may be correct. Engelder is correct to argue that if there was substantial flow or leakage from the shale, there would simply be no gas left. But the shale is not homogeneously impermeable; Boyer et al. (2006) described the shale as "notoriously heterogeneous" and even NYSDEC (2011) provides a large range of estimated permeability values. Fluids would easily drain naturally from more permeable and naturally fractured sections as well as allowing pathways for fluids from beneath shale to seep through. This would be the source of brine reaching the surface. Some portions of the shale are capped due to low permeability and this is where the gas remains for exploitation. HF will fracture the caps and shale, releasing both gas and brine. If there is a gradient and a pathway, fluids will flow vertically up from the shale. Brine trapped in the low permeability areas is likely the oldest groundwater in the basin (Gassiat et al. 2013b). HF increases permeability up to three times the in situ value (King 2012), an increase which would connect the formations above and below the shale and completely change the regional hydrogeology (Gassiat et al. 2013a; Myers in review).

Additionally, the only way that all HF fluid remains within the shale to be imbibed is for there to be no out-of-formation fractures resulting from HF stimulation. It has been accepted for several years that fractures extend above the shale (Fisher and Warpinski 2011), a recent detailed study has shown that over 10,000 fractures extended above the shale, some as much as 1900 feet, due to the HF of the 52 fracking stages of six horizontal Marcellus shale wells (Hammack et al 2014). This is the amount of fractures above the formation caused by fracking from just one well pad. Each fracture represents a pathway of fluid leaving the shale formation to contact sandstone, limestone, and other much more permeable formations above the shale.

Two studies have simulated flow from and through the shale to shallow groundwater (Gassiat et al. 2013a; Myers 2012). Myers (2012) considered simple one-dimensional (vertical) flow from the shale to the surface to show under what conditions such flow was possible and how long the flow might take. Due to the low impermeability, flow was found to take thousands of years but, not surprisingly, some hydraulic conditions allowed much faster flow. Those favorable conditions included a transmissive fault with a vertical connection from the shale to the surface. Myers (2012) found that HF fluid could reach shallow aquifer in time frames as short as decades. Gassiat et al. (2013) completed similar modeling but in two-dimensions. Their modeling developed regional shallow flow circulation from recharge. They simulated HF in the same way as Myers (2012), essentially just changing the shale permeability in the area undergoing HF. They showed that HF fluid could reach the surface in less than 1000 years in concentrations as high as 10% of that injected into the shale. Myers (in review) used a quasi-three-dimensional model to show also that HF fluid can reach shallow groundwater in time frames measured in hundreds of years.

In addition to a pathway, there must be a gradient to drive contaminants from the shale to the surface. There are at least three potential sources: catagenesis, topography, and glacial unloading. Catagenesis is the thermal decomposition of kerogen (see http://en.wikipedia.org/wiki/Kerogen for a detailed description) which forms the methane within the shale from organic matter. Because the gas cannot escape, it builds to high pressure. Once the shale is fractured, this pressure contacts the overlying formations and establishes a gradient, which Engelder (2012) stated ranges from 0.7 to 0.85 psi/ft. Hydrostatic pressure is 0.433 psi/ft and higher gradients provide an upward driving force; here, as much as 0.4 psi/ft. Gassiat et al. (2013) essentially relied on this type of gradient to drive their flow from the shale. The second source is simple topography, wherein recharge to formations beneath the shale occurs in formation that outcrops on high elevation ridges and flows through the formation to deep underground (Toth 1963). Because the recharge zone is far above the formations that lie beneath the Marcellus shale, they could be under substantive pressure.

The third mechanism is glacial unloading, wherein up-to-one-km thick glacial ice had compressed the ground surface and increased the pressure at depth. After the glaciers melted, the residual pressure at depth causes the ground surface to rebound until the excess pressure has dissipated. Such residual pressure effectively causes areas where the pressure would push fluid and gas upwards. Neither mechanism has been demonstrated in the Appalachian Basin although there is plenty of evidence of upward gradients (Warner et al. 2012a; Williams 2010; TAL 1981) and certainly sufficient formation outcrops on ridges and glacial rebound from the last Ice Age. Myers (in review) simulated circulation both below and above the shale based on recharge to formation outcrops in areas of higher relief to cause zones of high pressure to establish the gradient to drive flow through the fractured shale to the surface.

Critique of Standard

The standard requires operators to establish an Area of Review (AOR) within which they should conduct a comprehensive examination of the subsurface geology, but they only say the AOR should encompass "both the vertical and horizontal legs of the planned well." This is insufficient because the operator would be allowed to simply consider a vertical cross-section starting at the vertical borehole and extending along the horizontal portion. The Guidance for Auditors specifies that the "outer bound of the AOR will be the distance of the maximum predicted length of hydraulic fractures in each direction plus a margin of safety to be determined by the operator" (p 5). The standards do not require the operator to prove that the predicted length is accurate, to use any particular method for estimating it, or establish the factor of safety. This could lead to substantial differences in the size of the AOR among operators and auditors which would cause substantial differences in the quality of the geologic examinations.

The concern should be that a contaminant reaches a pathway leading to shallow groundwater. Since transport up a fault or abandoned well would be the fast way a contaminant could reach shallow groundwater, the AOR should be based on contaminant travel time from the point of HF to a fault. The critical horizontal pathway from the HF zone to a vertical pathway is through formations overlying the shale. Throughout Pennsylvania, this includes the Hamilton Formation which consists variously of siltstone, shale, and sandstone (Williams 2010; Williams et al. 1998; Taylor 1984; Lloyd and Carswell 1981). The permeability is highly variable and the conductivity at such a depth is generally not measured, but based on the lithology the permeability could be as high as 10^{-13} m^2 (0.3 ft/d) (Freeze and Cherry 1979). Myers (in review) modeled conductivity as 0.18 ft/d. For example, if 1000 years is the time frame for protection, with a reasonable horizontal gradient equal to 0.01 ft/ft (which could be higher) and porosity of 0.05, the geology up to 22,000 feet (0.3 ft/d x 0.01 ft/ft/0.05 x 1000 years x 365 d/y) or 4.2 miles from the well bores should be mapped for geology.

The Guidance for Auditors (p 5) does note that the AOR "may incorporate multiple wells from a single pad." Treating a specific pad as a system is preferable if multiple wells will be constructed from a pad. If the standard does not consider an AOR as a circle centered on the pad with a radius based on horizontal transport calculations such as the one specified above for the length beyond the end of the longest horizontal well bore, the AOR will be too small. This is because contaminants can transport from fracked wells a significant horizontal distance before beginning vertical transport, either through faults or abandoned wells. Cross-sections should be completed along any horizontal well bore.

The most important geologic feature claimed to prevent the vertical movement of HF fluid is the confining layer above the target zone. The geologic characterization required by the standard includes a "risk analysis" to demonstrate "the presence of an adequate confining layer above the production zone that will prevent adverse migration of HF fluids." The standard does not specify what "adequate" means in this context and therefore provides no assurance that the risks are sufficiently low.

A risk analysis generally attempts to determine the probability that a specific occurrence will occur. Probability is used because the parameters that go into the calculation are uncertain or unknown. Confining layers, even thick layers of shale, are heterogeneous such that permeability may vary substantially around the layer. Flow will occur through zones with the highest permeability, which means the majority may flow through just a small portion of the layer. Thus, the estimate of the vertical conductivity of the confining layer over the entire AOR must account for the higher permeability areas. The standard does not specify how the operator should estimate permeability, but borehole analysis only provides point source estimates that are highly unlikely to include the high permeability zones. Due to the difficulties of estimating more than a few points and due to issues of scale, for which the effective conductivity becomes larger as the area increases, the estimate of the conductivity of confining layers will be unreliable and the public has little assurance that shallow groundwater will not be contaminated.

The same lack of clarity and specifics applies to investigating "geologic vulnerabilities" meaning faults and fractures penetrating the confining layer. The standard does not even specify a minimum level of review. The Guidance for Auditors states that "seismic images, well logs, predrill well plans, wellbore schematics, etc." (p 5) will be adequate supporting data to support the mapping of faults and fracture zones. This is insufficient and simply not specific enough.

A geologic investigation starts with a review of existing geology maps, but must include development of a lineament and fracture trace map of the AOR that includes field surveys to verify whether the identified feature is human caused (Neilsen et al. 2006; Fetter 2001, section 12.2). If mapping yields unclear results, as is possible in heavily vegetated areas, the operator should perform gravity and magnetic surveys such as performed by Jacobi (2002) to supplement lineament surveys in New York. Surface surveys however provide indications only of near-surface conditions whereas the faults of importance to long-term transport from the shale occur at depth. The most direct route for transport to the surface is a continuous fault, but transport could also occur through a series of faults that connect permeable layers through deep confining zones and then through shallow faults to groundwater aquifers. The operator should analyze well logs and complete seismic reflection surveys to assess the deep structure associated with mapped surface structure (Jacobi 2002) as well as to map additional deep faults.

Additionally, the standard does not define what is meant by "adverse migration" with respect to HF fluids, although presumably CSSD intends it to be migration to shallow groundwater. Because of the one-year time frame used for sampling wells discussed under Standard 6, this standard presumably therefore refers to migration to shallow groundwater during a short period after the HF operations. Generally, "adverse" would be related to concentration at a point of concern, with a breakthrough for a given contaminant occurring when a given concentration at a point is reached. A problem with defining "adverse" is that many chemicals in HF fluid may be hazardous but due to differing transport properties the transport of one chemical may be adverse while that of another chemical may not be.

The requirement for there to be "a thorough investigation of any active or abandoned wellbores" is good, although the standards fail to define "thorough." The standard does not require a field investigation or survey for abandoned wells even though there are many abandoned wells that have not been mapped by state authorities. The standard does not provide the public with any confidence that there are no unplugged abandoned wells that could allow fluids to move toward the surface.

Finally, the standard calls for the operator to "adequately address identified risks", without specifying what that means. The standard does not require that abandoned wells be plugged so that that they cannot be conduits for vertical flow from depth or provide for a sufficient setback from any fault that potentially provides a pathway from depth to shallow groundwater. A reasonable setback would be 1000 years of travel time based on standard transport calculations, as outlined above. Such a time period is reasonable considering the likelihood that preferential flow along parts of the pathway would be much faster than assumed. It is also reasonable in comparison to the standards used for other facilities potentially developing hazardous conditions, such as mines that plan to capture and treat seepage in perpetuity or hazardous waste disposal sites.

The standard does not consider out-of-formation fracturing at all, but the Guidance for Auditors requires the operator provide data to show that such will be minimal. Although it is very unlikely that HF-induced fractures will reach shallow groundwater or the surface, the fractures may provide connectivity across the lower 1500 feet of the overburden. Out-of-formation fracturing reduces the vertical distance that HF fluids must travel to reach shallow groundwater by the length of the fracture. HF could fracture the confining layer being relied upon to prevent vertical movement of fluid. By essentially ignoring out-of-formation fracturing, the standards provide no assurance that out-of-formation fractures will not cause adverse migration of HF fluids or NG.

Performance Standard 6

1. Operators shall develop and implement a plan for monitoring existing water sources, including aquifers and surface waters (as defined in the CSSD Guidance for Auditors document) within a 2,500 foot radius of the wellhead (or greater distance, if a need is clearly indicated by geologic characterization), and demonstrate that water quality and chemistry measured during a pre-drilling assessment are not impacted by operations.
2. Operators must conduct periodic monitoring for at least one year following completion of the well. Such monitoring must be extended if results indicate potential adverse impacts on water quality or chemistry by operations.
3. In the event that monitoring establishes a possible link between an Operator's activities and contamination of a water source, the Operator shall develop and implement an investigative plan and, if a positive link is established, implement a corrective action plan.
4. The testing and monitoring plan should provide for additional monitoring in the event a well is re-stimulated.[2]

The standard requires monitoring of existing water sources, including wells, springs, and streams, for a brief period following the development of individual wells. Both industry and conservation sources have called for improved groundwater monitoring of HF operations, including dedicated monitoring well sys-

2 Center for Sustainable Shale Development (CSSD). 2013. Performance Standards. Pittsburgh PA: CSSD.

tems (Myers 2012; Molofsky et al. 2013). For example, New York has proposed dedicated monitoring well systems, rather than simple monitoring of existing wells. Sampling existing water wells will not protect the aquifers but will simply show if a given well has become contaminated during the brief period proposed for sampling. Sampling as required in these standards will not detect long-term transport from depth.

Background

Groundwater quality monitoring either detects a leak by considering the presence/absence of a constituent or shows the changes in the concentration of a constituent with time. The first step in designing a monitoring system is to determine its purpose. That purpose will allow a definition of the type of wells and the time they will be monitored.

Domestic wells make lousy monitoring wells for the following reasons (Thyne p 10-11):

- Domestic wells are generally screened over large intervals which makes it difficult to identify from which formation any detected contamination emanates
- The wells are not constructed to facilitate measurement of the water table elevation or downhole sampling. Sampling must therefore occur at the surface after pumping which increases the possibility of introducing contaminants during sampling
- It is difficult to arrange access to take samples due to privacy issues
- There may be liability issues for damage during sampling and interruption of water supply.

Domestic wells are simply not appropriate for long-term monitoring of trends. They are only useful for detection of a constituent.

A monitoring well system should be designed so that a contaminant plume will neither pass horizontally between the monitoring wells nor above or below the screened interval. The goal of the monitoring will determine the design of the well since groundwater drawn from a well will be a conglomerate of all the producing zones spanned by the screen. Therefore, if the screen spans multiple lithologies, the water within the well bore may dilute the concentration emanating from one of the lithologies (Shosky 1987). However, a long screen will increase the chances of detecting the presence of an expected contaminant which may indicate the site being monitored has developed a leak. On the other hand, layer specific sampling with short well screens will give an accurate representation of the aquifer.

Monitoring concentrations requires layer specific sampling and allows for a three-dimensional representation of a plume. Contamination from a leak on the surface would initially contaminate the upper portion of the aquifer. Contaminants transporting upwards through faults will encounter the bottom of aquifer and disperse through the aquifer vertically and horizontally. Therefore, concentrations will vary horizontally and vertically throughout an aquifer regardless of the source. Wells that sample wide sections of the aquifer may not provide any guidance as to the source of contamination.

The spatial layout of a dedicated monitoring well system should be based on a conceptual flow and transport model for the aquifer, flow pathways and possible contaminant dispersion from the NG well to the aquifer. The Guidance for Auditors notes that the monitoring should be "informed by the proximity of sensitive areas and/or receptors" and to "reference the geological characterization and summarize surficial geology/geomorphology and topography streams, identifying potential ground and surface water flow directions and vulnerabilities …" (p 6). This is good as long as it is part of a conceptual flow model of the area. Monitoring wells should be placed as close to the expected flow path as possible. The concentration will be highest along the flow pathway with lesser concentrations lateral to the flow path. Because of uncertainty in the predicted flow path, monitoring wells should also be spaced laterally away from the flow path. Monitoring wells should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that a monitoring well will intercept the contaminant and to assess the rate of transport. To detect contamination from depth, the pathways from the shale through any faults zones to the shallow aquifer must be mapped and monitored. This may not be necessary if sufficient care was taken to avoid faults.

The monitoring well system must be sampled frequently enough to minimize the chance that a plume will pass between sampling events. Many natural geologic and climatic features affect the rate of contaminant movement with and through the groundwater. A temporary leak that does not disperse may pass a site in just a few days whereas a continuous leak may cause a slow concentration increase occasionally diluted by natural recharge. Transport from the shale along a fault system could occur for centuries (Gassiat et al. 2013; Myers 2012).

Sampling should occur sufficiently often to minimize the chance that contaminant plumes could bypass the monitoring system. Based on professional judgment and experience, most sampling regimes should include at least a year of monthly sampling to establish the seasonal changes. After the sampling frequency decreases to quarterly, there should be a plan to increase to monthly if a parameter of interest begins to increase or exceed standards. Additionally, monitoring wells should include continuous sampling of electrical conductivity (ec), pH, and water level so that the time frames associated with recharge events and the potential short-term leak can be recorded and considered.

Critique of Standard

The standard requires that a "plan for monitoring existing water sources, including aquifers and surface waters" be developed to "demonstrate that water quality and chemistry measured during a pre-drilling assessment are not impacted by operations." Having a plan is better than not having one, but as written this standard fails on all of the factors required to establish a decent monitoring system as described in the Background to this section. First, the use of the word aquifer is good in that an aquifer is an extensive geologic formation that provides water to the wells and springs which tap and discharge from it. However, the standard and Auditor's document requires only that existing wells be monitored and then only for "at least one year", which is only a tiny fraction of the potential travel time for transport from the shale.

The standard specifies only that monitoring continue for "at least one year following completion of the well." The standard is ambiguous here because it does not consider the other wells on the pad. Each well from a given pad threatens the same water resources. Because of the different contaminant sources (surface spills and leaks, pits, transport, deep on the well bore, or the shale) and the types of contaminants, the potential travel times to an existing monitoring well will vary from months to potentially centuries. The standard must require much longer monitoring and be based upon the conceptual flow model of the site.

The Guidance for Auditors document (p 6) indicates that "[o]perators are not required to resample each water source sampled as part of pretesting." This implies that wells with previous sampling do not need to be resampled, but the point of monitoring is to establish a trend or to establish the presence of a constituent not previously observed in the source. This is another way that monitoring as specified in the standards is insufficient.

If a possible link is "established between an Operator's activities and contamination of a water source, the Operator shall develop and implement an investigative plan." The standard should specify what would be a possible link. One, detection of a HF chemical should be considered to have established a possible link. Perhaps more confusingly, an upward trend in some constituent, such as potassium or alkalinity (DiGuilio et al. 2011), may indicate an effect of HF or well development. The standard should specify an increase, such as an increase over the standard deviation of the pre-HF monitoring results, that will indicate a possible link. If there are too few pre-HF samples to determine a standard deviation, the standard should specify an increase with the upper limit being the groundwater standard if the pre-HF level was below the standard.

Upon the identification of a possible link, the standard requires that the operator "develop and implement an investigative plan" to determine whether there is a "positive link" between the activities and the contamination. "Positive" implies certainty, but there is always uncertainty in the field of environmental forensics so requiring a positive link seems to be extreme. The standard does not define what is meant by "positive"; however positive is defined, it should be less than complete proof. For example, the exact pathway for contaminant transport is likely impossible to identify, and this should not be required. Circumstantial evidence, such as isotopic signatures, geochemistry, the presence/absence of HF fluids, the presence of NG in a well just after a HF event, should be sufficient proof that the HF operations caused the contamination. The lack of adequate dedicated monitoring systems, as described above, cannot be used as an excuse to claim there is no positive link.

The auditor document indicates that the monitoring plan be performed by a qualified third party using recognized methods. This is generally a good idea, but sampling should also be performed at times not known in advance to the operator to prevent the operator causing the source to be flushed or otherwise affected by activities. As described, the standard does not adequately prevent the operator from altering the monitoring results.

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Sustainable Energy Options

Excerpted from the writings of Mark Z. Jacobson

Rather than debating whether hydraulic fracturing for natural gas development can ever be made safe, we should instead be focusing on how to convert to a truly safe and sustainable energy system, including an unqualified commitment to energy efficiencies and conservation measures. Such a system would be comprised of wind, water, and solar (WWS) power, and would be cheaper than our current fossil fuel system over the long term.

Mark Z. Jacobson, a professor of Civil and Environmental Engineering at Stanford University, has extensively studied the ability to convert to a sustainable, renewable energy system. Excerpts and conclusions from his publications are set out in this paper.

Converting to Sustainable Energy Options Can Power and Benefit Our Nation

Jacobson has developed plans for conversion for individual states, the entire United States, and the world. In his research, Jacobson found that the greatest barriers to this conversion are not "technical or even economic" but are instead "social and political."[1]

> The plans contemplate all new energy powered with WWS by 2020, about 80-85% of existing energy replaced by 2030, and 100% replaced by 2050. Electrification plus modest efficiency measures would reduce each state's end-use power demand by a mean of 37.6% with ~85% of this due to electrification and ~15% due to end-use energy efficiency improvements. Remaining 2050 all-purpose end-use U.S. power demand would be met with ~31% onshore wind, ~19% offshore wind, ~29.6% utility-scale photovoltaics (PV), ~8.6% rooftop PV, ~7.5% concentrated solar power (CSP), ~1.3% geothermal power, ~0.37% wave power, ~0.13% tidal power, and ~2.5% hydroelectric power. Over the U.S. as a whole, converting would provide ~5 million 40-year construction jobs and ~2.4 million 40-year operation jobs for the energy facilities alone, the combination of which would outweigh the ~3.9 million jobs lost. Converting would also eliminate ~62,000 (19,000-116,000) of today's U.S. air pollution premature mortalities/year and avoid ~$510 (158-1,155) billion/year in today's U.S. health costs, equivalent to ~3.15 (0.98-7.13) percent of the 2012 U.S. gross domestic product. Converting would further eliminate ~$730 billion/year in 2050 global warming costs due to U.S. emissions. The health cost savings to the U.S. plus the climate cost savings to the world due to U.S. emission reductions would equal the cost of installing a 100% WWS U.S. system within ~11.0 (7.3-15.4) years.[2]

Conversion to a 100% WWS energy infrastructure would eliminate energy-related air pollution mortality and morbidity, and the associated health costs. For example, a world conversion to a WWS system would eliminate "2.5-3 million annual air pollution deaths."[3]

> The conversion to WWS should stabilize energy prices since fuel costs would be zero. On the other hand, because the fuel costs of fossil fuels rise over time, a WWS infrastructure in 2050 would save the average U.S. consumer $4,500/person/year compared with the 2050 energy cost of fossil fuels to perform the same work. Health and climate cost savings due to WWS would be another $3,100/person/year benefit, giving a total cost savings in 2050 of $7,600/person/year due to WWS.
>
> The new footprint over land required for converting the U.S. to WWS for all purposes is equivalent to ~0.44% of the U.S. land area, mostly in deserts and barren land, before accounting for land gained from eliminating the current energy infrastructure. The spacing area between wind turbines, which can be used for multiple purposes, including farmland, ranchland, grazing land, or open space, is equivalent to 1.7% of U.S. land area. Grid reliability can be maintained in multiple ways. The greatest barriers to a conversion are neither technical nor economic. They are social and political. Thus, effective polices are needed to ensure a

1 Delucchi and Jacobson, 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies, Energy Policy 39, 1170.

2 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 1.

3 Jacobson, 2012. Why Natural Gas Warms the Earth More but Causes Less Health Damage Than Coal, so is not a Bridge Fuel nor a Benefit to Climate Change, October 31, 2012 *Draft*, 1.

rapid transition."[4]

Jacobson's roadmaps for states to convert to WWS detail anticipated infrastructure changes.

> In brief, [conversion] requires or results in the following changes:
>
> (1) Replace fossil-fuel electric power generators with wind tur- bines, solar photovoltaic (PV) plants and rooftop systems, concentrated solar power (CSP) plants, solar hot water heater systems, geothermal power plants, a few additional hydro-electric power plants, and a small number of wave and tidal devices.
>
> (2) Replace all fossil-fuel combustion for transportation, heating and cooling, and industrial processes with electricity, hydrogen fuel cells, and a limited amount of hydrogen combustion. Battery-electric vehicles (BEVs), hydrogen fuel cell vehicles (HFCVs), and BEV–HFCV hybrids…will replace all combustion-based passenger vehicles, trucks, buses, non-road machines, and locomotives sold...Long-distance trucks will be primarily BEV-HFCV hybrids and HFCVs. Ships…will similarly run on hydrogen fuel cells and electricity. Today, hydrogen-fuel-cell ships, tractors, forklifts, buses, passenger vehicles, and trucks already exist, and electric vehicles, ferries, and non-road machinery also exist. Electricity-powered air- and ground-source heat pumps, heat exchangers, and backup electric resistance heaters will replace natural gas and oil for home heating and air conditioning. Air- and ground-source heat pump water heaters powered by electricity and solar hot water preheaters will provide hot water for homes. High-temperatures for industrial processes will be obtained with electricity and hydrogen combustion. Petroleum products may still be used for lubrication and plastics as necessary, but such products will be produced using WWS power for process energy.
>
> (3) Reduce energy demand beyond the reductions described under (2) through energy efficiency measures. Such measures include retrofitting residential, commercial, institutional, and government buildings with better insulation, improving the energy-out/energy-in efficiency of end uses with more efficient lighting and the use of heat-exchange and filtration systems; increasing public transit and telecommuting, designing future city infrastructure to facilitate greater use of clean-energy transport; and designing new buildings to use solar energy with more daylighting, solar hot water heating, seasonal energy storage, and improved passive solar heating in winter and cooling in summer.
>
> (4) Boost economic activity by implementing the measures above. Increase jobs in the manufacturing and installation industries and in the development of new and more efficient technologies. Reduce social costs by reducing health-related mortality and morbidity and reducing environmental damage to lakes, streams, rivers, forests, buildings, and statues resulting from air and water pollution. Reduce social costs by slowing the increase in global warming and its impacts on coastlines, agriculture, fishing, heat stress, severe weather, and air pollution (which otherwise increases with increasing temperatures). Reduce long-term macroeconomic costs by eliminating exposure to future rises in fossil fuel prices.
>
> (5) The plan anticipates that the fraction of new electric power generators as WWS will increase starting today such that, by 2020, all new generators will be WWS generators. Existing conventional generators will be phased out over time, but by no later than 2050. Similarly, BEVs and HFCVs should be nearly the only new vehicles…sold…by 2020. The growth of electric vehicles will be accompanied by a growth of electric charging stations in residences, commercial parking spaces, service stations, and highway rest stops.
>
> (6) All new heating and cooling technologies installed by 2020 should be WWS technologies and existing technologies should be replaced over time, but by no later than 2050.
>
> (7) To ensure reliability of the electric power grids, several methods should be used to match renewable energy supply with demand and to smooth out the variability of WWS resources. These include (A) combining geographically-dispersed WWS resources as a bundled set of resources rather than as separate resources and using hydroelectric power to fill remaining gaps; (B) using demand-response grid management to shift times of demand to match better with the timing of WWS power supply; (C)

4 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 1-2.

over- sizing WWS peak generation capacity to minimize the times when available WWS power is less than demand and to provide power to produce heat for air and water and hydrogen for transportation and heating when WWS power exceeds demand; (D) integrating weather forecasts into system operation to reduce reserve requirements; (E) storing energy in thermal storage media, batteries or other storage media at the site of generation or use; and (F) storing energy in electric-vehicle batteries for later extraction (vehicle-to-grid)."[5]

Why Wind, Water and Solar Are the Best Technology Options to Fuel Our Healthy Future

Jacobson's state roadmaps rely on technologies that will reduce air and water pollution and global warming impacts.

> The WWS energy technologies chosen…exist and were ranked the highest among several proposed energy options for addressing pollution and public health, global warming, and energy security (Jacobson, 2009). That analysis used a combination of 11 criteria (carbon dioxide equivalent emissions, air-pollution mortality and morbidity, resource abundance, footprint on the ground, spacing required, water consumption, effects on wildlife, thermal pollution, water, chemical pollution/radioactive waste, energy supply disruption, and normal operating reliability) to evaluate each technology. Mined natural gas and liquid biofuels are excluded from the…plan for the reasons given below.[6]

Natural gas was excluded from Jacobson's analysis

> for several reasons. The mining, transport, and use of conventional natural gas for electric power results in at least 60–80 times more carbon-equivalent emissions and air pollution mortality per unit electric power generated than does wind energy over a 100-year time frame. Over the 10–30 year time frame, natural gas is a greater warming agent relative to all WWS technologies and a danger to the Arctic sea ice due to its leaked methane and black carbon-flaring emissions…Natural gas mining, transport, and use also produce carbon monoxide, ammonia, nitrogen oxides, and organic gases. Although natural gas emits less carbon dioxide per unit electric power than coal, two factors cause natural gas to increase global warming relative to coal: higher methane emissions and less sulfur dioxide emissions per unit energy than coal…[N]atural gas is not a near-term 'low' greenhouse-gas alternative, in absolute terms or relative to coal. Moreover, it does not provide a unique or special path to renewable energy, and as a result, it is not bridge fuel and is not a useful component of a sustainable energy plan.
>
> Rather than use natural gas in the short term, [Jacobson et al.,] propose[s] to move to a WWS-power system immediately, on a worldwide scale, because the Arctic sea ice may disappear in 20–30 years unless global warming is abated (e.g., Pappas, 2012). Reducing sea ice uncovers the low-albedo Arctic Ocean surface, accelerating global warming in a positive feedback. Above a certain temperature, a tipping point is expected to occur, accelerating the loss to complete elimination (Winton, 2006). Once the ice is gone, regenerating it may be difficult because the Arctic Ocean will reach a new stable equilibrium (Winton, 2006). The only potential method of saving the Arctic sea ice is to eliminate emissions of short-lived global warming agents, including methane (from natural gas leakage and anaerobic respiration) and particulate black carbon (from natural gas flaring and diesel, jet fuel, kerosene burning, and biofuel burning)."[7]

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Converting to Sustainable Energy Is Feasible

Jacobson has documented that we have the sustainable energy capacity necessary to power the United States.

5 Jacobson et al., 2013. Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight, Energy Policy 57, 586.

6 For reasons why nuclear power and coal with carbon capture are also excluded, see Jacobson and Delucchi (2011).

7 Jacobson et al., 2013. Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight, Energy Policy 57, 586-587.

The United States has more wind, solar, geothermal, and hydroelectric resources than is needed to supply the country's energy for all purposes in 2050. In this section, U.S. wind, solar, geothermal, hydroelectric, tidal, and wave resources are examined.

Wind

…Results suggest that the U.S. mean onshore capacity factor may be 30.5% and offshore, 37.3%. Locations of strong onshore wind resources include the Great Plains, northern parts of the northeast, and many areas in the west. Weak wind regimes include the southeast and the westernmost part of the west coast continent. Strong offshore wind resources occur off the east coast north of South Carolina and the Great Lakes. Very good offshore wind resources also occur offshore the west coast and offshore the southeast and gulf coasts…[T]he 2050 clean-energy plans require 1.7% of U.S. onshore land and 0.88% of U.S. onshore-equivalent land area sited offshore for wind-turbine spacing to power 50% of all-purpose 2050 U.S. energy. The mean capacity factor for onshore wind needed is 35.2% and that for offshore wind is 42.5%. Figure 1 suggests that much more land and ocean areas with these respective capacity factors or higher are available than are needed for the plans.

Solar

…The best solar resources in the U.S. are broadly in the Southwest, followed by the Southeast, the Northwest, then the Northeast. The land area in 2050 required for non-rooftop solar under the plan here is equivalent to ~0.41% of U.S. land area, which is a very small percent of area relative to the area of strong solar resources available in Figure 2 and in other solar resource analyses. As such, we do not believe there is a limitation in solar resources available for implementing the 50 state plans proposed …

Geothermal

The U.S. has significant traditional geothermal resources (volcanos, geysers, and hot springs) as well as heat stored in the ground due to heat conduction from the interior of the Earth and solar radiation absorbed by the ground. In terms of traditional geothermal, the U.S. has an identified resource of 9.057 GW[8] deliverable power distributed over 13 states, undiscovered resources of 30.033 GW deliverable power, and enhanced recovery resources of 517.8 GW deliverable power (USGS, 2008). As of April, 2013, 3.386 GW of geothermal capacity had been installed in the U.S. and another 5.15-5.523 GW was under development (GES, 2013).

States with identified geothermal resources (and the percent of resource available in each state) include Colorado (0.33%), Hawaii (2.0%), Idaho (3.68%), Montana (0.65%), Nevada (15.36%), New Mexico (1.88%), Oregon (5.96%), Utah (2.03%), Washington State (0.25%), Wyoming (0.43%), Alaska (7.47%), Arizona (0.29%), and California (59.67%). All states have the ability to extract heat from the ground for heat pumps. However, such energy would not be used to generate electricity; instead it would be used directly for heat, thereby reducing electric power demand for heat although electricity would still be needed to run heat pumps…

Hydroelectric

Under the plan proposed here, conventional hydro will supply 47.26 GW of delivered power, or 2.46% (Table 1) of U.S. 2050 total end-use power demand for all purposes. Thus, 2010 U.S. plus Canadian delivered hydropower (34.8 GW) already provides 73.6% of the U.S. 2050 delivered hydropower power goal. The plan here calls for very few new hydroelectric dams. Thus, the additional 12.5 GW of delivered hydro would be obtained by increasing the capacity factor of existing dams to an average of 53.1%. Existing dams currently provide less than their maximum capacity due to an oversupply of energy available from other sources and multiple priorities affecting water use…

Tidal

Tidal (or ocean current) is proposed to comprise about 0.13% of U.S. total power in 2050 (Table 1). The U.S. currently has the potential to generate 50.8 GW (445 TWh/yr)[9] of delivered power from tidal streams (Georgia Tech Research Corporation, 2011). States with the great-

8 GW or gigawatt. One GW is equal to one billion watts or 1,000 megawatts (MW).

9 TWh, or terawatt hour. One TW is equal to one trillion watts.

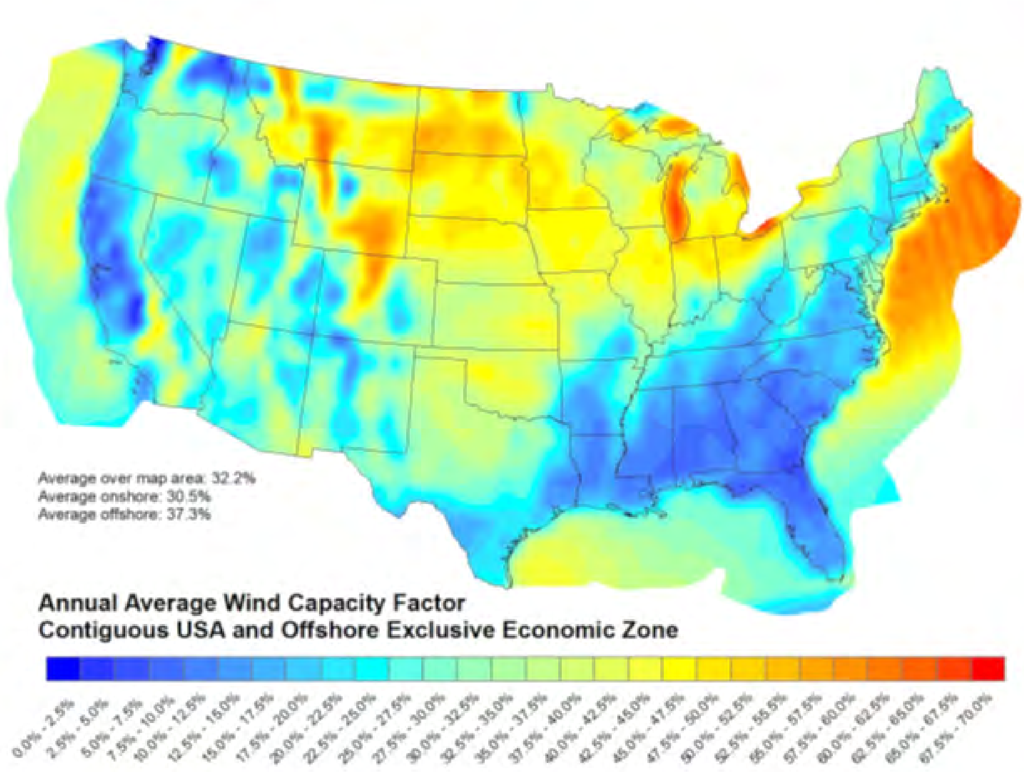

Figure 1. Modeled 2006 annually averaged capacity factor for 5 MW RePower wind turbines (126-m diameter rotor) at 100-m hub height above the topographical surface in the contiguous United States. The model used was GATOR-GCMOM (Jacobson et al., 2007; Jacobson, 2010), which was nested for one year from the global to regional scale with resolution on the regional scale of 0.6 degrees W-E x 0.5 degrees S-N.

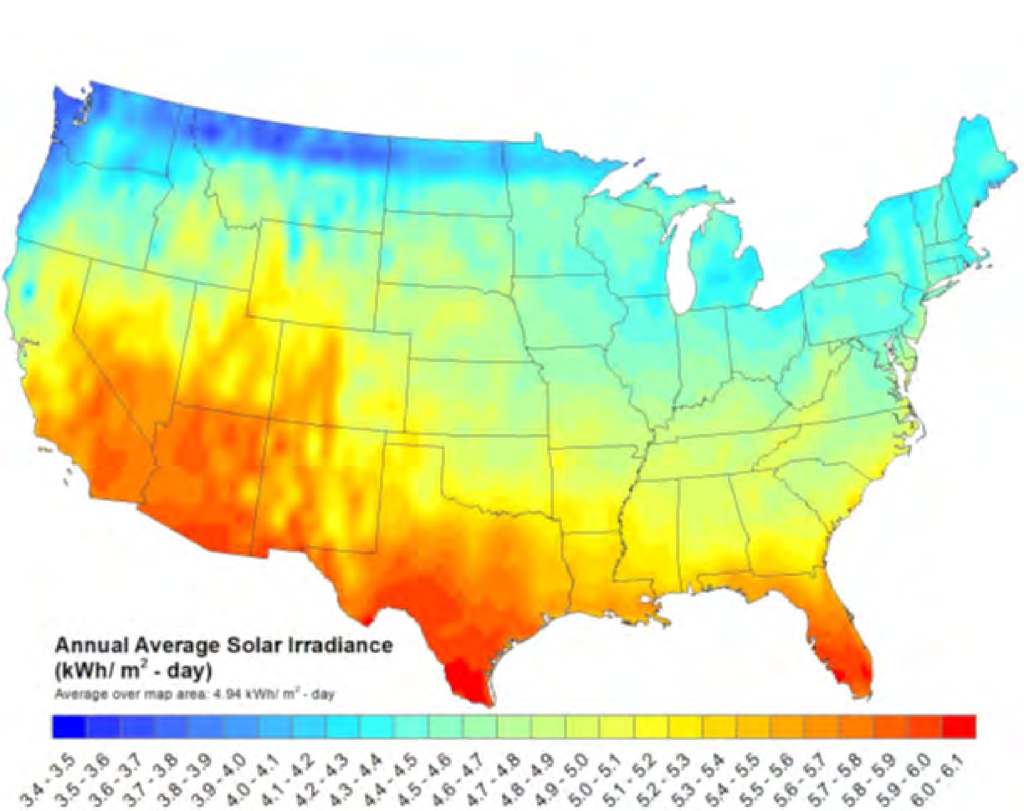

Figure 2. Modeled 2013 annual downward direct plus diffuse solar radiation at the surface (kWh/m_2/day) available to photovoltaics in the contiguous United States. The model used was GATOR-GCMOM (Jacobson et al., 2007; Jacobson, 2010), which simulates clouds, aerosols gases, weather, radiation fields, and variations in surface albedo over time. The model was nested from the global to regional scale with resolution on the regional scale relatively coarse (0.6 deg W-E x 0.5 deg S-N).

Energy Technology	Rated power of one plant or device (MW)	Percent of 2050 power Demand met by plant/device	Nameplate capacity of existing plus new plants or devices (MW)	Percent of nameplate capacity already installed 2013	Number of new plants or devices needed for U.S.	Percent of U.S. land area for footprint of new plants / devices[A]	Percent of U.S. land area for spacing of new plants / devices
Onshore wind	5	30.98	1,818,769	3.36	351,547	0.00005	1.7057
Offshore wind	5	18.99	904,726	0.00	180,945	0.00002	0.8779
Wave device	0.75	0.37	33,657	0.00	44,876	0.00026	0.0122
Geothermal plant	100	1.29	28,935	8.32	265	0.00099	0.0000
Hydroelectric plant	1300	2.46	92,816	95.92	4	0.02701	0.0000
Tidal turbine	1	0.13	10,687	0.00	10,687	0.00003	0.0004
Res. roof PV	0.005	4.73	641,416	0.55	127,573,149	0.05208	0.0000
Com/gov roof PV	0.1	3.89	495,593	0.36	4,938,184	0.04032	0.0000
Solar PV plant[B]	50	29.62	2,923,981	0.06	58,444	0.23859	0.0000
Utility CSP plant	100	7.54	833,012	0.00	8,330	0.17275	0.0000
Total		100.00	7,783,592	2.05	0	0.53	2.60
Total new land[C]						0.44	1.71

A Total land area for each state is given in Jacobson, M.Z., G. Bazouin, and M.A. Delucchi, 2014a. Spreadsheets of calculations for this study. http://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-50-USState-plans.html.

B The solar PV panels used for this calculation are Sun Power E20 panels. The capacity factors used for residential and commercial/government rooftop solar production estimates are given in Jacobson et al. (2014a) for each state. For utility solar PV plants, nominal "spacing" between panels is included in the plant footprint area. The capacity factors assumed for utility PV are given in Jacobson et al. (2014a).

C The footprint area requiring new land is equal to the footprint area for new onshore wind, geothermal, hydroelectric, and utility solar PV. Offshore wind, wave and tidal are in water, and so do not require new land. The footprint area for rooftop solar PV does not entail new land because the rooftops already exist and are not used for other purposes (that might be displaced by rooftop PV). Only onshore wind entails new land for spacing area. The other energy sources either are in water or on rooftops, or do not use additional land for spacing. Note that the spacing area for onshore wind can be used for multiple purposes, such as open space, agriculture, grazing, etc.

Table 1. Number, capacity, footprint area, and spacing area of WWS power plants or devices needed to provide the U.S. total annually-averaged end-use power demand for all purposes in 2050, accounting for transmission, distribution, and array losses. Individual tables for each state and their derivation are given in Jacobson et al. (2014a).

…Short- and moderate distance transmission and distribution losses for offshore wind and all other energy sources treated here were assumed to be 5-10%. Since each state's plan is self-contained, extra-long distance transmission was assumed not necessary. However, If it were needed, losses from it would be 1.4-6% per 1000 km plus 1.3-1.8% in the station equipment (Delucchi and Jacobson, 2011).

est potential offshore tidal power include Alaska (47.4 GW), Washington State (683 MW), Maine (675 MW), South Carolina (388 MW), New York (280 MW), Georgia (219 MW), California (204 MW), New Jersey (192 MW), Florida (166 MW), Delaware (165 MW), Virginia (133 MW), Massachusetts (66 MW), North Carolina (66 MW), Oregon (48 MW), Maryland (35 MW), Rhode Island (16 MW), Alabama (7 MW), Texas (6 MW), Louisiana (2 MW). The available power in Maine, for example, is distributed over 15 tidal streams. The present state plans call for extracting just 2.5 GW of delivered power, which would require an installed capacity of 10.7 GW of tidal turbines.

Wave

Wave power is also proposed to comprise 0.37%, or about 7.1 GW, of the U.S. total end-use power demand in 2050 (Table 1). The U.S. has a recoverable delivered power potential (after accounting for array losses) of 135.8 GW (1,190 TWh) along its continental shelf edge (EPRA, 2011). This includes 28.5 GW of recoverable power along the West Coast, 18.3 GW along the East Coast, 6.8 GW along the Gulf of Mexico, 70.8 GW along Alaska's coast, 9.1 GW along Hawaii's coast, and 2.3 GW along Puerto Rico's coast. Thus, all states border the oceans have wave power potential. The available supply is almost 20 times the delivered power needed under this plan."

…Short- and moderate distance transmission and distribution losses for offshore wind and all other energy sources treated here were as-

> sumed to be 5-10%. Since each state's plan is self-contained, extra-long distance transmission was assumed not necessary. However, If it were needed, losses from it would be 1.4-6% per 1000 km plus 1.3-1.8% in the station equipment (Delucchi and Jacobson, 2011).[10]

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Sustainable Energy is Reliable

Jacobson has determined that WWS can provide the power when and where it is needed.

> An important concern to address in a clean -energy economy is whether electric power demand can be met with WWS supply on a minutely, daily, and seasonal basis…Several studies have examined whether up to 100% penetrations of WWS resources could be used reliably to match power with demand (e.g., Jacobson and Delucchi, 2009; Mason et al., 2010; Hart and Jacobson, 2011, 2012; Connolly et al., 2011; Elliston et al., 2012; NREL (NationalRenewableEnergyLaboratory), 2012; Rasmussen et al., 2012; Budischak et al.,2013). Using hourly load and resource data and accounting for the intermittency of wind and solar, both Hart and Jacobson (2011) and Budischak et al. (2013) found that up to 99.8% of delivered electricity could be produced carbon-free with WWS resources over multiple years…Eliminating remaining carbon emission is challenging but can be accomplished in several ways. These include using demand response and demand management, which will be facilitated by the growth of electric vehicles; oversizing the grid and using the excess power generated to produce district heat through heat pumps and thermal stores and hydrogen for other sectors of the energy economy (e.g. heat for buildings, high-temperature processes, and fuel-cell vehicles); using concentrated solar power storage to provide solar power at night; and storing excess energy at the site of generation with pumped hydroelectric power, compressed air (e.g. in underground caverns or turbine nacelles), flywheels, battery storage packs, or batteries in electric vehicles (Kempton and Tomic, 2005). Oversizing the peak capacity of wind and solar installation to exceed peak inflexible power demand can reduce the time that available WWS power supply is below demand, thereby reducing the need for other measures to meet demand. The additional energy available when WWS generation exceeds demand can be used to produce hydrogen (a storage fuel) by electrolysis for heating processes and transportation and to provide district heating. Hydrogen must be produced in any case as part of the WWS solution. Oversizing and using excess energy for hydrogen and district heating would also eliminate the current practice of shutting down (curtailing) wind and solar resources when they produce more energy than the grid can accommodate. Denmark currently uses excess wind energy for district heating using heat pumps and thermal stores (e.g., Elsman, 2009).[11]

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Sustainable Energy Is Cost Effecient

The cost of sustainable energy will continue to decrease over time. By comparison, conventional fuel costs are expected to rise over time, making sustainable energy the better near term and long term choice based on cost.

> With a 100% WWS market penetration proposed for 2050, significant cost reductions are expected not only due to anticipated technology improvements and the zero fuel cost of WWS resources, but also due to less expensive manufacturing and streamlined project deployment from increased economies of scale. On the other hand, private electricity costs of conventional fuels are expected to continue to rise.
>
> Costs of onshore wind and hydroelectric power are expected to remain low through 2030. The cost of wind-generated electricity has declined recently due to the rapid decline in turbine prices and improvements in technology leading to increased net capacity factors (e.g. increases in average hub height and rotor diameter). National costs of solar PV are expected to fall to 4.5-10 cents/kWh by 2030, with the low-end reduction for utility-scale solar and the high end for residential. With this expected price reduction, solar PV is expected to be competitive with other energy sources throughout the U.S. by significantly before 2030.
>
> Due to the nascent state of the wave and tidal industries (the first commercial power projects have just now been deployed in the United States), it is difficult to make accurate cost estimates. Roughly 50 different tidal devices are in the proof-of-concept or prototype development stage, but large-scale deployment costs have yet to be demonstrated. Although current wave power-generating technologies appear to be expensive, they might follow a learning curve similar to that of the wind power industry. Industry analyses point toward a target annualized cost of 4-11 U.S. ¢/kWh for wave and 5-7 ¢/kWh for tidal power (Asmus and Gauntlett, 2012), although a greater understanding of costs will become available once systems in the field have been in operation for a few years.
>
> …[M]any future wind and solar farms may be far from population centers, requiring long-distance transmission. For long-distance transmission, high-voltage direct-current (HVDC) lines are used because they result in lower transmission line losses per unit distance than alternating-current (AC) lines (Table 1, footnote). The cost of extra-long-distance HVDC transmission on land (1,200-2,000 km) ranges from 0.3-3 U.S. cents/kWh, with a median estimate of ~1 U.S. cent/kWh (Delucchi and Jacobson, 2011). A system with up to 25% undersea HVDC transmission would increase the additional long-distance transmission cost by less than 20%. Transmission needs and costs can be reduced by considering that decreasing transmission capacity among interconnected wind farms by 20% reduces aggregate power by only 1.6% (Archer and Jacobson, 2007).
>
> … [E]ven with extra-long-distance HVDC transmission, the costs of hydroelectric and wind power are already cost competitive with fossil electricity sources. In fact, a state by-state examination of fractional electricity generation by wind versus cost of electricity by state provides the following results. From January-July 2013, two states (South Dakota and Iowa) generated nearly 28% of their electric power from wind. Nine states generated more than 13% from wind (South Dakota, Iowa, Kansas, Minnesota, North Dakota, Oklahoma, Idaho, Colorado, and Oregon). The tenth state, Texas, generated 9.3% of its electricity from wind (EIA, 2013a). The average increase in residential electricity price from 2003-2013 in the 10 states with the highest fraction of their electricity from wind was 3 ¢/kWh. The price increase during the same period in all other 40 states was 4 ¢/kWh. The price increase in Hawaii during the same period

was 19.9 ¢/kWh. This result suggests that states that invested more in wind saw less of a price increase than states that invested less in wind, contrary to the perception that the addition of an intermittent renewable energy source causes an average increase in electricity price.[12]

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Sustainable Energy Options Avoid Expensive Air Pollution Costs and the Damage it Does to Our Health and Lives

Jacobson has also considered the considerable human health implications of converting to WWS.

> *The top-down approach to estimate air-pollution mortality in the U.S.* The premature human mortality rate in the U.S. due to cardiovascular disease, respiratory disease, and complications from asthma due to air pollution has been estimated conservatively by several sources to be at least 50,000-100,000 per year. In Braga et al. (2000), the U.S. air pollution mortality rate was estimated at about 3% of all deaths. The all-cause death rate in the U.S. is about 833 deaths per 100,000 people and the U.S. population in 2012 was 313.9 million. This suggests a present-day air pollution mortality rate in the U.S. of ~78,000/year. Similarly, from Jacobson (2010), the U.S. death rate due to ozone and particulate matter was calculated with a three-dimensional air pollution-weather model to be 50,000-100,000 per year. These results are consistent with those of McCubbin and Delucchi (1999), who estimated 80,000 to 137,000 due to all anthropogenic air pollution in the U.S. in 1990, when air pollution levels were higher than today.
>
> *The bottom-up approach to estimate air-pollution mortality in the U.S.* This approach involves combining measured countywide or regional concentrations of particulate matter ($PM_{2.5}$) and ozone (O_3) with a relative risk as a function of concentration and with population by county. From these three pieces of information, low, medium, and high estimates of mortality due to $PM_{2.5}$ and O_3 pollution are calculated with a health-effects equation (e.g., Jacobson, 2010)…The medium values for the U.S. for $PM_{2.5}$ were ~48,000 premature mortalities/yr…and for O_3 were ~14,000 premature mortalities/yr, with a range of 7,000-21,000/yr. Thus, overall, the bottom-up approach gives ~62,000 (19,000-116,000) premature mortalities/year for $PM_{2.5}$ plus O_3. The top-down estimate (50,000–100,000), from Jacobson (2010), falls within the bottom-up range.
>
> …[T]he total social cost [of fossil fuel-based energy] due to air pollution mortality, morbidity, lost productivity, and visibility degradation in the U.S. today is conservatively estimated from the ~62,000 (19,000-116,000) premature mortalities/yr to be $510 (158-1,155) billion/yr (using an average of $8.2 million/mortality for the low and medium numbers of mortalities and $10 million/mortality for the high number). Eliminating these costs today represents a savings equivalent to ~3.15 (0.98-7.13)% of the 2012 U.S. gross domestic product.
>
> Energy-related greenhouse gas emissions from the U.S. cause climate-related damage to the world… Ackerman et al. (2008) estimated global warming damage costs (in 2006 U.S. dollars) to the U.S. alone due to world emissions of greenhouse gases and warming aerosol particles of $271 billion/yr in 2025, $506 billion/yr in 2050, $961 billion/yr in 2075, and $1.9 trillion/yr in 2100. That analysis accounted for severe storm and hurricane damage, real estate loss, energy-sector costs, and water costs. The largest of these costs was water costs. It did not account for increases in mortality and illness due to increased heat stress, influenza, malaria, and air pollution or increases in forest-fire incidence, and as a result it probably underestimated the true cost.
>
> …[C]onverting the U.S. to WWS would avoid $510 (158-1,155) billion/year in air pollution

12 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 24-27.

health costs to the U.S. and ~$730 billion/yr in global-warming damage costs worldwide by 2050. The U.S.-mean installed capital cost of the electric power system proposed here, weighted by the proposed installed capacity of each generator, is approximately $1.8 million/MW. Thus, for new nameplate capacity, summed over all generators, of 7.63 TW (Table 1), the total capital cost of a U.S. WWS system is ~ $13.7 trillion. As such, the health-cost savings alone to the U.S. due to converting to WWS may equal the installation cost of WWS generators within 27 (12-87) years. The health-cost savings to the U.S. plus the climate-cost savings to the world may equal the generator cost within 11 (7.3-15.4) years.

…[M]odels predict the creation of ~4.95 million 40-year construction jobs and ~2.4 million 40-year operation and maintenance jobs for the WWS generators proposed. The shift to WWS will simultaneously result in the loss of ~3.88 million in the current fossil-based electricity generation, petroleum refining, and uranium production industries in the U.S. Thus, a net of ~3.48 million 40-year jobs will be created in the U.S. The direct and indirect earnings from WWS amount to $271 billion/year during the construction stage and $152 billion/yr for operation. The annual earnings lost from fossil-fuel industries total ~$233 billion/yr giving a net gain in annual earnings of ~$190 billion/yr. These numbers are not meant to be a precise forecast, but rather an indication of the economic effect WWS electricity generation may have on the U.S. The actual job and revenue impacts are subject to various uncertainties associated with progress in technology, projects scale and policies. Overall, the positive socio-economic impacts of WWS resource electricity implementation are expected to exceed significantly the negative impacts."[13]

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A Sustainable Energy Future is Achievable

Sustainable energy to fuel our future is within our grasp. To get the health, environment and economic benefits of sustainable energy and leave behind the damage of shale gas and continued use of fossil fuels, we just need to take the steps to make it happen.

> Manpower, materials, and energy resources do not constrain the development of WWS power; the obstacles to realizing this transformation are primarily social and political, not technological.[14] With clear direction in the form of broad-based policies and relatively small social changes "it may be possible for a 25% conversion in 10-15 years, 85% in 20-30 years, and 100% by 2050."[15]
>
> Least-cost energy system optimization studies and practical implementation considerations will determine the most efficient design and operation of the energy system… Several methods exist to match renewable energy supply with demand and to smooth out the variability of WWS resources" and to reduce costs associated with the transition.[16]

In the United States, approximately 40% of the total annual carbon dioxide emissions are associated with the generation of electricity.[17] Implementation of a WWS energy system will essentially "eliminate the costs related to these emissions such as energy-related global warming; air, soil, and water pollution; and energy insecurity.[18]

13 Jacobson et al., 2014. 100% Wind, Water, Sunlight (WWS) All-Sector Energy Plans for the 50 United States, July 17, 2014 *Draft*, 36.

14 Delucchi and Jacobson, 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies, Energy Policy 39, 1170.

15 Delucchi and Jacobson, 2011. Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies, Energy Policy 39, 1179.

16 Jacobson, et al., 2014. A 100% Wind, Water, Solar (WWS) All-Sector Energy Plan for Washington State, July 14, 2014 *Draft*, 44.

17 Hart and Jacobson, 2011, A Monte Carlo approach to generator portfolio planning and carbon emissions assessments of systems with large penetrations of variable renewables, Energy Policy 36, 2278, citing Energy Information Administration. Annual energy outlook 2009, table a18, http://www.eia.doe.gov/oiaf/aeo/pdf/appendixes.pdf; 2009.

18 Jacobson, et al., 2014. A 100% Wind, Water, Solar (WWS) All-Sector Energy Plan for Washington State, July 14, 2014 *Draft*, 46.

About the Photographs

All photographs by Delaware Network Staff unless otherwise indicated

Cover: clockwise from top center: Gas flare, Hop Bottom, Pennsylvania; Natural gas pipeline, Pike County, Pennsylvania; Tap water sampling of private well affected by a gas pipeline, Pike County, Pennsylvania; Greenlick Compressor Station, Susquehannock State Forest, Potter County, Pennsylvania, courtesy of PA Forest Coalition; Gas well site, Susquehanna County, Pennsylvania

viii: Outcropping of Marcellus Shale, Holt Preserve in Feura Bush, New York

Page 3: clockwise from top right: Spectra Compressor Station, West Amwell Township, New Jersey; Natural gas pipeline crossing of the West Branch Lackawaxen, Pennsylvania; Drilling rig at Marcellus shale well site, Susquehanna County, Pennsylvania

Page 4: Gas well pad under construction, Susquehanna County, Pennsylvania

Page 6: clockwise from top right: Natural gas pipeline construction, Pike County, Pennsylvania; Gas well pads and pit under construction, Susquehanna County, Pennsylvania; Gas well site, Susquehanna County, Pennsylvania.

Page 16: Drilling services truck, Dimock, PA

Page 18: top: Gas well flaring, Hop Bottom, Pennsylvania; bottom: West Amwell Compressor Station, Hunterdon County, New Jersey

Page 23: Gas well pad and pit under construction, Susquehanna County, Pennsylvania

Page 24: Completed gas well site, Susquehanna County, Pennsylvania

Page 26: Drilling rig at Marcellus Shale gas well site, Dimock, Pennsylvania

Page 41: Private well being vented due to methane contamination, Franklin Forks, Pennsylvania

Page 42: top: Frack waste tanker, Dimock, Pennsylvania; bottom: Frack pit, shale gas well site, Washington County, Pennsylvania

Page 44: clockwise from top right: Air monitor outside home near well site in western Pennsylvania; Gas well pad under construction, Susquehanna County, Pennsylvania; Completed gas well site, Susquehanna County, Pennsylvania; Filling of a basin at gas well site, Dimock, Pennsylvania

Page 52: Tanks, completed gas well site, Susquehanna County, Pennsylvania

Page 54: clockwise from top left: Tap water sampling of private well affected by a gas pipeline, Pike County, Pennsylvania; Shale gas well, Washington County, Pennsylvania; Drilling rig at Marcellus shale well site, Dimock, Pennsylvania

Page 64: Shale gas well site next to cattle farm, Susquehanna County, Pennsylvania

Page 65: Frack pit, shale gas well site, Washington County, Pennsylvania

Page 66: Windmills, Wayne County, Pennsylvania

Inside back cover: The East Branch Delaware River near Downsville, New York

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