NATURAL RESOURCES DEFENSE COUNCIL

July 31, 2014

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Michigan Department of Environmental Quality
PO Box 30256
Lansing MI 48909-7756

RE: NRDC Comments on Oil and Gas Operations Rules Proposed Draft June 2014; Department of Environmental Quality Office of Oil, Gas, and Minerals

Dear Chief Fitch:

Thank you for the opportunity to comment on the Michigan Department of Environmental Quality's (DEQ or "the Department") proposed rules entitled, "Oil and Gas Operations, Proposed Draft June 11, 2014."[1] These comments are submitted on behalf of the Natural Resources Defense Council (NRDC) and our over 35,000 members and activists in the state of Michigan. While we write separately to emphasize certain issues omitted from DEQ's current proposal, we also support the comments being submitted by our colleagues at Anglers of the Au Sable, Michigan Environmental Council, Michigan League of Conservation Voters, National Wildlife Federation, Tip of the Mitt, and Trout Unlimited, proposing specific changes to the current draft rules.

As noted in comments by these same groups earlier this year, Michigan is a relatively new entrant into high volume, horizontal hydraulic fracturing, or "hydrofracking." With this more intensive form of oil and gas development comes a host of potential threats to the state's natural resources and the health of its people, including contamination from chemicals used in the hydrofracking process and draw down of local water resources to supply the fracturing process.

Significant work remains to be done to evaluate the risks posed by hydrofracking—some of which is already being conducted by a variety of public and private actors, including an examination by the U.S. EPA into the potential impact of hydrofracking on drinking water resources and significant new research by academics and health professionals, such as the Graham Institute's Integrated Assessment of Hydrofracking in Michigan. In recognition that additional study is necessary to assess the full measure of risks from

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[1] The proposed rules are available at http://www7.dleg.state.mi.us/orr/Files/ORR/1298_2013-101EQ_orr-draft.pdf. The comment period for the proposed rules closes on July 31, 2014.

hydrofracking, and how, if at all, they can be addressed, states like New York have put off the permitting of proposed new hydrofracking until this critical analysis can be performed. Michigan should similarly pause to allow time both for independent study and its own more thorough evaluation of the activity, rather than rushing forward. Promulgation of a few purported fixes coupled with continued permit issuance under inadequate regulations fails to make good on DEQ's obligation to prevent "waste"—a term that state law broadly defines to include harm to environmental values as well as squandering of oil and gas resources.[2]

Further, both DEQ's current and proposed rules contain significant deficiencies—even with respect to what is known today—in terms of their content and critical omissions. Therefore, to the extent the state fails to take a time out on permit issuance to await a full understanding of the risks, we strongly advise that DEQ strengthen its proposed rules now so as to better protect the public's health and welfare. We are disappointed at the agency's response to date in rejecting the vast majority of the well-reasoned amendments previously proposed by the above-mentioned groups, and hope that the agency takes the opportunity in this round of review to do so.

Along with the concerns highlighted in the above-cited group comments, DEQ should investigate and propose rule amendments to address the following issues:

- Protections for Michigan's local communities;
- Protections for Michigan's natural and historic resources;
- Protections for Michigan's drinking water resources, including long-term water monitoring around well sites;
- Improved responsiveness to resident complaints;
- Comprehensive planning for wastewater management;
- Comprehensive planning for emissions reductions from oil and gas activities;
- The potential for induced seismicity from hydrofracking; and
- Increased transparency and information sharing.

Although we recognize that many of these comment areas fall outside the specific scope set forth for the proposed rulemaking, we believe that DEQ must address these concerns as expeditiously as possible. To the extent that addressing these concerns within the context of the present rulemaking is determined not to be possible or would significantly delay other beneficial proposed regulations from taking effect, DEQ should promptly institute another rulemaking.

Without significant improvements in the areas identified in these comments, Michigan is putting its citizens and natural resources in harm's way, and is falling behind other states and provinces that are making serious efforts to grapple with the impacts of hyrdrofracking. Given advances in these other states and provinces, Michigan falls far short of being a leader on hydrofracking policy.

[2] See Mich. Comp. Laws Ann. § 324.61501(q).

The Proposed Rules Should Provide Enhanced Regulatory Protections for Michigan's Local Communities

Because the rapid intrusion of hydrofracking and/or other oil and gas operations into communities can cause significant harm to their character and development goals—in addition to the health, property, and welfare of individual local residents—the proposed rules should include enhanced protections for Michigan's communities, as well as provisions for mandatory solicitation and response to local feedback on proposed well locations and other land use matters.

Hydrofracking is a heavy industrial activity that is often plainly incompatible with certain community areas—for example, rural or suburban neighborhoods or sensitive agricultural areas. Aside from its aesthetic ugliness, the drilling and fracturing of an oil or gas well often involves days or weeks of twenty-four-hour-a-day illumination and high-decibel noise[3] in addition to the traffic, noise, and road wear and tear caused by the thousands of heavy truck trips necessary to support the well site.[4] Further, because each well pad is capable of carrying up to twelve individual wells,[5] cumulatively, a single site may be the source of years' worth of around-the-clock nuisance activity—a disturbance only compounded where multiple well sites exist within a neighborhood. Inevitably, in areas where residents have cultivated and are accustomed to a tranquil standard of living, these activities interfere with local planning goals, the protection of home values,[6] and the quiet enjoyment of property. Such persistent disruptions may also affect health, potentially contributing to hypertension, psychological symptoms, loss of sleep, and fatigue.[7]

In addition to health impacts from persistent stress factors, hydrofracking also carries risks of direct injury to resident health and the environment. Although the most dramatic incidents are well-explosions, termed "blowouts," which can have grave consequences

[3] The New York Department of Environmental Conservation studied these impacts in a draft environmental impact statement, which remains under review. *See* N.Y. State Dep't of Envtl. Conservation, *Revised Draft Supplemental Generic Envtl. Impact Statement* (2011) [hereinafter "NY Draft EIS"] *available at* http://www.dec.ny.gov/energy/75370.html. That draft report finds that, for a typical well accessing the Marcellus Shale, initial creation of the well requires "four to five weeks of drilling 24 hours per day to complete" during which operational noise is commonly audible for thousands of feet (6-289, 6-293 to 6-296); large drill rigs—about 150 feet high—must be illuminated at night; and during well production (6-274); hydrofracking of the well requires two to five days of up to "20 diesel-pumper trucks operating simultaneously," generating noise levels of up to 84 decibels (6-296).

[4] *See Id.* at 6-301 to 6-303 (each horizontal well requires approximately 1,975 heavy and 1,420 light truck trips).

[5] *See* Jim Ladlee & Jeffrey Jacquet, *The Implications of Muli-Well Pads in the Marcellus Shale*, 43 Cornell Univ. & Penn State Research & Policy Brief Series (2011) *available at* http://cce.cornell.edu/EnergyClimateChange/NaturalGasDev/Documents/PDFs/Policy_Brief_Sept11-draft02.pdf.

[6] *See* Lucija Muehlenbachs et al., *The Housing Market Impacts of Shale Gas Dev*., Nat'l Bureau of Econ. Research Working Paper No. 19796 (Jan. 2014) (finding values of groundwater-dependent homes negatively affected by proximity to hydrofracking wells), *available at* http://public.econ.duke.edu/~timmins/MST_AER_1_3_2014.pdf.

[7] *See* Colo. Sch. of Pub. Health, *Battlement Mesa Health Impact Assessment (2d Draft)* (Feb. 2011) 52–54 *available at* http://www.garfield-county.com/environmental-health/battlement-mesa-health-impact-assessment-ehms.aspx.

for persons or property within the blast or heat radius,[8] more commonplace are air and/or water pollution from accidents, poor well construction, or, disturbingly, normal well operations. In Pennsylvania, for example, state regulators recently confirmed that oil and gas operations had impacted water supplies in at least 209 instances within the past seven years[9] (and other recent revelations about that state's poor record keeping and response to citizen complaints suggest that such incidents may be even more common).[10] Residents in active shale plays also commonly report experiencing headaches, nosebleeds, or nausea (or, in some cases upper respiratory, neurological, and dermatological symptoms) shortly after the commencement of nearby hydrofracking, and these symptoms are consistent with health effects associated with exposure to petroleum hydrocarbons.[11] Additionally, air emissions from standard hydrofracking operations have been detected at levels that pose increased risks of cancer and other health threats to those living near gas wells,[12] and one study also found that living next to hydrofracking wells is correlated with higher rates of birth defects.[13]

These common impacts highlight two important points: (1) even under ideal regulatory conditions, the generation of significant community nuisances—such as constant light, jarring noise, and traffic—happen with predictable regularity, and (2) more severe impacts, whether due to human error, unforeseen circumstances, or gaps in regulatory standards or enforcement, have been observed throughout the nation under a variety of regulatory regimes. In both circumstances, residents may be put at risk personally, their property may be damaged or devalued, and the vitality of the local or regional economy

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[8] *See* Catherine Greene, *Growth Patterns in the U.S. Organic Indus.*, USDA (Oct. 24, 2013) (describing a hydrofracking well blowout that shot "flames several stories into the air and preventing authorities from getting closer than 300 yards because of the blistering heat") *available at* http://triblive.com/state/pennsylvania/5575457-74/dispatcher-county-emergency#axzz2tF5OS3Ka.

[9] Katie Colaneri, *Pa. regulators document 209 cases of water damage from oil and gas operations*, StateImpact (Jul. 22, 2014) [hereinafter "Colaneri (2014)"], *available at* http://stateimpact.npr.org/pennsylvania/2014/07/22/pa-regulators-document-209-cases-of-water-contamination-from-drilling/.

[10] Eugene A. DePasquale, Pennsylvania Auditor General, *DEP's performance in monitoring potential impacts to water quality from shale gas dev., 2009-2012*, (Jul. 21, 2014) *available at* http://www.auditorgen.state.pa.us/reports/performance/special/speDEP072114.pdf.

[11] *See* John L. Adgate, *Potential Pub. Health Hazards, Exposures & Health Effects from Unconventional Natural Gas Dev.*, Envtl. Sci. & Tech. (Feb. 24, 2014) [hereinafter "Adgate (2014)"] *abstract available at* http://pubs.acs.org/doi/abs/10.1021/es404621d; N. Steinzor et al., *Investigating Links Between Shale Gas Impacts and Health through a Cmty. Survey Project in Pa.*, 23(1) New Solutions 55 (2013) (study finding higher percentage of residents living next to oil and gas well sites reported health symptoms that were similar across project locations, regardless of age group or smoking history, and consistent with exposure to oil and gas contaminants detected in ambient air outside residents' homes) [hereinafter "Steinzor (2013)"], *available at* http://www.earthworksaction.org/files/publications/SteinzorSubraSumiShaleGasHealthImpacts2013.pdf.

[12] *See, e.g.*, Lisa M. McKenzie et al., *Human Health Risk Assessment of Air Emissions from Dev. of Unconventional Natural Gas Res.*, Nat'l Center for Biotechnology Info. (2012) [hereinafter "McKenzie et al. (2012)"] *available at* http://bit.ly/1pcNPuF.

[13] *See* Lisa McKenzie et al., *Birth Outcomes and Maternal Residential Proximity to Natural Gas Dev. in Rural Colo.*, Envtl. Health Perspectives (Jan. 28, 2014) (finding, *inter alia*, women who lived close to oil and gas wells had a higher rate of babies born with defects in their hearts than women who lived in areas with no oil and gas wells) [hereinafter "McKenzie, *Birth Outcomes* (2014)"] available *at* http://ehp.niehs.nih.gov/wp-content/uploads/122/4/ehp.1306722.pdf; McKenzie et al. (2012).

may be diminished (for example, nuisances from hydrofracking may impair local tourism,[14] or a water contamination incident may significantly damage or shutter local food production industries like breweries or farms).[15]

In many states, such as Texas, New York, and Pennsylvania, local communities are able to exercise traditional zoning and land use authority to either mitigate significant community risks from hydrofracking or avoid them altogether.[16] In Texas, for example, the nation's top gas producing state,[17] municipalities have broad authority not only to control the location of proposed hydrofracking operations, but also may enact regulations controlling technical aspects of extraction, production, and well closure.[18] In Michigan, however, it may be determined that certain local governments, such as the state's townships and counties, are more limited in their ability to influence decisions regarding the location and operation of oil and gas activities.[19] Accordingly, while NRDC strongly supports the rights of all Michigan communities to determine where and how oil and gas drilling activities occur within local boundaries, in the absence of clear local authority, the gravity of the potential community harms from hydrofracking demands more robust community protections than are present in the current or proposed regulations.

As an initial matter, the proposed rules should contain stronger mandatory community protections, especially for sensitive areas. For example, the proposed rules preserve a previously applicable 300 foot setback for wells and surface facilities from "existing structures used for public or private occupancy,"[20] but this distance is generally insufficient to protect community character and health,[21] particularly in view of research

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[14] See, e.g., Christopherson, Ph.D., Comments on the 2011 Revised Draft Supplemental Generic Impact Statement regarding the social and econ. impacts of natural gas dev., 12-14 (Jan. 11, 2012) (citing evidence of disruption of tourism by hydrofracking in Western states, and potential serious and long-term consequences to tourism in New York from the possible future cumulative impacts of hydrofracking) available at http://docs.nrdc.org/energy/files/ene_12011201c.pdf at Attachment 5.

[15] *See* Michelle Bamberger & Robert E. Oswald, *Impacts of Gas Drilling on Human & Animal Health*, 22 New Solutions 51, 72 (2012) *available at* http://www.psehealthyenergy.org/data/Bamberger_Oswald_NS22_in_press.pdf; Rebecca Lesser, *New Test Assesses Impact of Gas Drilling, Pipeline Constr. on Soil Health*, Chronicle Online, Cornell Univ. (Mar. 31, 2010) (fallow agricultural lands "were found to have marked negative effects from pipeline construction") *available at* http://www.news.cornell.edu/stories/March10/soiltestdrilling.html.

[16] *See Unger v. State*, 629 S.W.2d 811, 812 (Tex. App. 1982); *Wallach v. Town of Dryden*, 2014 WL 2921399 (N.Y. June 30, 2014); *Robinson Twp., Washington Cnty. v. Commonwealth*, 83 A.3d 901 (Pa. 2013).

[17] U.S. Energy Info. Admin., *Which States Consume and Produce the Most Natural Gas*, *available at* http://www.eia.gov/tools/faqs/faq.cfm?id=46&t=8.

[18] *Unger*, 629 S.W. 2d at 812 ("[A]ppellee asserts that [a municipality], under its police power has full authority to both regulate and prohibit the drilling of oil wells within its city limits. We agree.").

[19] Mich. Comp. Laws § 125.3205.

[20] Proposed R 324.301(2).

[21] For example, a West Virginia study found health-threatening levels of diesel particulate and benzene in the air at 650 feet from well sites. Michael McCawley, Ph.D., *Air, Noise, and Light Monitoring Results For Assessing Envtl. Impacts of Horizontal Gas Well Drilling Operations (ETD-10 Project)*, prepared for the West Virginia Department of Environmental Protection (May 3, 2013) *available at* http://wvwri.org/wp-content/uploads/2013/10/A-N-L-Final-Report-FOR-WEB.pdf. And a study in rural Utah found levels of benzene higher than urban areas measured 950 feet away from the closest well, Detlev Helmig, *Highly Elevated Atmospheric Levels of Volatile Organic Compounds in the Uintah Basin, Utah*, Envtl. Sci. &

indicating that significant health risks associated with air emissions occur within at least half a mile from active wells.[22] Further, setbacks only from "occupied structures" leave other important of the community areas wholly unprotected. They do not, for instance, prevent a well site from being placed adjacent to a school playground or a residential backyard.

Perhaps in recognition of potential harms that even less-intensive conventional drilling presents to communities, the current rules prevent the siting of oil or gas surface facilities, flare stacks, pump jacks, and drilling mud pits in areas zoned as residential *before January 8, 1993*.[23] Worryingly, however, the rules do not justify why areas zoned residential in the last two decades are either more resilient or less deserving of protection than those designated before 1993.[24] The proposed rules should extend these protections to all residential zones, whenever so designated, and should also identify and establish protections for other common types of community areas in which oil and gas activities would likely be incompatible.

DEQ should also strengthen and expand protections within the existing rules that relate to the control of nuisances generated by oil and gas operations. For example, while both the proposed and current R 324.1015 forbid the generation of a "nuisance noise" and empower DEQ to require abatement, whether noise monitoring or abatement occur are largely discretionary. DEQ should modify R 324.1015 to include triggers for mandatory testing for and abatement of noise nuisances, and also modify its test for finding a noise nuisance to place the greatest weight on the decibel level actually recorded in the "noise-sensitive area."[25] Additionally, DEQ should consider whether other rules within Part 10 of the oil and gas regulations regarding nuisance controls may be strengthened, or new sections added (such as a section providing limitations on well-site-related-traffic).

In addition to providing these heightened protections, DEQ should also recognize that it will not be possible for it to identify, on a statewide basis, all of the community areas where the siting of hydrofracking or other oil and gas activities may cause injury. Indeed, the probable impact of the introduction of hydrofracking into a community will, to a large extent, only be foreseeable by its residents—who are the most familiar with and invested in the particularities of its history, existing economy, and character. To tap into this valuable local expertise, DEQ should also create a mandatory mechanism to actively solicit and incorporate community input into its permitting decisions (including whether to deny a permit in some circumstances) and other regulatory decisions that may have

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Tech. (Mar. 13, 2014) [hereinafter "Helmig et al. (2014)"] *available at* http://catskillcitizens.org/learnmore/es405046r.pdf.

[22] McKenzie et al. (2012).

[23] R 324.407; R 324.505; R 324.506.

[24] Similarly, there is little justification as to why a 450 ft. setback for residential buildings applies only in a "city or township with a population of 70,000 or more" but not to the Michiganders' homes in the rest of the state. M.C.L. § 324.61506b(b).

[25] Currently, it appears as if the noise level recorded at an arbitrary distance of 1,320 feet from the offending "surface facility" controls whether noise abatement orders will be issued. This is little comfort to those living, working, or recreating within 1,320 feet of the facility. R 324.1015(2) Further, the definition of "noise-sensitive area" should be expanded to include commercial areas where noise may interfere with business operations or attracting customers.

consequences for the communities in which Michiganders live, work, and raise their families.[26]

<u>The Proposed Rules Should Include Mandatory Protections for Michigan's Natural and Historic Resources</u>

The proposed rules fail to adequately identify or protect many of the state's vital natural and historic resources most at risk from the potential harms of nearby oil and gas drilling. These resources include:

- State designated natural rivers and federally designated wild or scenic rivers;
- Other surface water bodies or significant aquifers or watershed areas;
- Publicly owned or designated wildernesses, forests, parks, or wildlife areas;
- State designated critical dune areas;
- The presence or habitats of state or federally designated endangered or threatened species or other species of concern;
- State, federal, or locally designated historical or archeological areas;
- Regulated wetlands or important aquifer recharge areas; and
- Floodplains.

In the first instance, both the current and the proposed rules do not require identification of certain sensitive resources—such as, for example, historic or archaeologically significant areas—that are at risk of harm from oil and gas operations. This makes it impossible for DEQ to assess the impact of proposed drilling on these resources or ascertain what conditions may be necessary to prevent or mitigate any damage.

Further, even where sensitive resources are required to be identified, no modifications have been proposed to the existing survey requirements to account for the increased industrial footprint associated with hydrofracking.[27] Although inventory of a number of natural features is required for well permit applications, identification continues to be largely limited to within 1,320 feet of the surface location of only the vertical portion of a well.[28] This is irrespective of whether activities occurring on well pads or proposed access roads are likely to have impacts on sensitive resources beyond 1,320 feet from the drilled well. At a minimum, DEQ should increase the mandatory survey radius to 4,000 feet[29] and ensure that the radius extends from the full area where oil and gas activities are

[26] It is worth noting that in at least one state, Pennsylvania, the failure of the state to take into account individualized community considerations when establishing a statewide plan for the siting of hydrofracking and other oil and gas extraction activities was considered a violation of constitutional substantive due process. *Robinson Twp., Washington Cnty. v. Commonwealth*, 284 M.D. 2012, 2012 WL 1429454 (Pa. Commw. Ct. Apr. 20, 2012).
[27] *See* Proposed R 324.201.
[28] See Id.
[29] The current regulations already provide increased survey radii for certain resources. For example, R 324.201(2)(b)(iv)(H) requires that applicants identify "[a]ll public water supply wells identified as type I and IIa that lie within 2,000 feet of the proposed well location." As noted, however, a 4,000 foot radius is recommended.

actively occurring—such as from the perimeters of the well pad, the horizontal wellbores or "producing intervals," and access roads.

The Department should also require permit applicants to consult with appropriate agencies charged with the care of the state's sensitive resources. In Pennsylvania, for example, the state Department of Environmental Protection has proposed rules that would require applicants to provide "proof of consultation with the Pennsylvania Natural Heritage Program (PNHP) regarding the presence of a State or Federal threatened or endangered species where the proposed well site or access road is located."[30] The proposed rules should similarly require consultation with Michigan state agencies such as the Department of Natural Resources and the State Historic Preservation Office.

Sensitive resources or areas must not only be identified, however, they must also be protected. While the current draft of the proposed rules does maintain previously applicable setbacks from certain drinking water resources (specifically, recorded and reasonably identifiable fresh water wells and public water supply wells),[31] there are no similar mandatory prohibitions relating to other natural or historic resources or sensitive areas as have been proposed in other states. Illinois law, for example, prevents high volume hydrofracking within certain distances from a "perennial stream or from the ordinary high water mark of any river, natural or artificial lake, pond, or reservoir" or a nature preserve.[32] And in New York, the state's most recent draft of proposed rules for hydrofracking would prevent all high volume hydraulic fracturing on state lands (including state parks), 100-year floodplains, or within 4,000 feet of the New York City watershed.[33] Similarly, Michigan's proposed rules should include mandatory protections for the state's valuable natural and historic resources.

The Proposed Rules Should Increase Protections for Michigan's Drinking Water Resources

The proposed rules preserve existing setbacks from well sites to recorded or reasonably identifiable fresh water wells (300 feet), and from well separators, storage tanks, and treatment equipment to public water supplies (800 to 2,000 feet),[34] but more can be done to protect Michigan's valuable drinking water resources. As noted above, other states have proposed stronger measures to prevent contamination of important state drinking water resources.[35] In addition to prohibiting high volume hydraulic fracturing activities within 100-year floodplains or within 4,000 feet of the New York City watershed, New York's Department of Environmental Conservation has also proposed prohibiting hydraulic fracturing well pads within 2,000 feet of the intake of a public drinking water

[30] Proposed 25 Pa. Code § 78.15(d).
[31] R 324.301(2), (3).
[32] 225 ILCS 732/1-25(a)(4), (5)
[33] Proposed 6 NYCRR §§ 52.3, 750-3.3(a).
[34] R 324.301.
[35] For example, in Illinois, wells may not be located within 1,500 feet of a public water supply intake. 225 ILCS 732/1-25(a)(6).

supply (including a 1,000 foot prohibition zone on each side of an upstream water body or tributary for one mile) and on or within 500 feet of a "primary aquifer."[36]

Events like last summer's flooding of a number of Colorado hydrofracking sites,[37] recent revelations about industry-wide issues with well integrity,[38] and reports that that hundreds hydrofracking wells across the country are either believed or confirmed to have contaminated drinking water supplies[39] all demonstrate the need to zealously guard the state's water resources. Accordingly, the proposed rules should establish a 4,000 foot setback from all current or potential drinking water resources, such as primary aquifers, public water supplies, private drinking water wells, surface water bodies, and aquifer recharge zones.

Also, as noted above, where multiple wells are drilled at a pad or multiple well pads are developed within the same general area, the risk of impacts, including water contamination, increases.[40] The proposed rules should therefore also require DEQ to consider the potential short and long term cumulative impacts of oil and gas operations whenever the Department is considering simultaneously permitting a large number of oil and gas activities in a single area, or in an area with existing oil and gas activities or other industrial development.

The Proposed Rules Should Include a Provision for Concurrent and Long-Term Monitoring of Water Supplies

The proposed rules do not adequately consider or address the risks of water contamination that can persist long after well site operations have ended. A leading cause of water contamination from oil and gas activity is well integrity failure resulting from problems with the cementing or casing of the well itself, which happen often during oil and gas operations,[41] but can also occur several years or decades after well closure and

[36] Proposed 6 NYCRR § 750-3.3(a). As noted below, we recommend that *at least* a 4,000 foot setback be established for all drinking water resources, including primary aquifers ("Primary aquifer" is defined in New York as "a highly productive aquifer presently being utilized as a source of water supply by a major municipal supply system." Proposed 6 NYCRR § 560.2(b)(20)).

[37] Cathy Proctor, *Colo. flood-related oil spills total nearly 43,000 gallons*, Denver Business Journal (Sep. 30, 2013) *available at* http://bit.ly/1lYDf86.

[38] *See* Richard Davies et al., *Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation*, 56 Marine and Petroleum Geology (Sep. 2014) *available at* http://bit.ly/UAkalm.

[39] Katie Colaneri (2014); Kevin Begos, *4 states confirm water pollution from drilling*, Associated Press (Jan. 5, 2014) *available at* http://www.usatoday.com/story/money/business/2014/01/05/some-states-confirm-water-pollution-from-drilling/4328859/.

[40] *See* NY Draft EIS at 6-16 ("The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure").

[41] *See* Anthony R. Ingraffea et al., *Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pa., 2000–2012*, Proceedings of the Nat'l Acad. of Scis. (May 30, 2014) (projecting that over 40 percent of shale gas wells in Northeastern Pennsylvania will leak methane into groundwater or the atmosphere over time, identifying high occurrences of casing and cement impairments inside and outside the wells, and finding that newer, unconventional (horizontally fractured) shale gas wells were leaking at six times the rate of conventional (vertical) wells drilled over the same time period) *available at* http://www.pnas.org/content/early/2014/06/25/1323422111.abstract; Maurice Dusseault et al.,

site abandonment.[42] Additionally, at least one study has shown that longer-term vertical contaminant migration from the shale itself may be possible under certain conditions.[43] Despite the fact that contamination may occur years or even decades after an oil or gas well has been plugged, the proposed rules only provide for concurrent water supply monitoring near *water withdrawal* wells and baseline water quality sampling around oil and gas well sites before the commencement of operations.[44] No provision is made for regular sampling of water supplies during oil and gas operations or after well completion and abandonment.

DEQ should require water quality monitoring around oil and gas well sites that is designed to detect both concurrent and long-term contaminant migration around oil and gas well sites. To give the Department a sense of what such a monitoring program may look like, we attach the expert report of Doctor Tom Myers as Exhibit A to these comments,[45] which was earlier submitted as part of joint technical comments on New York's regulatory proposal for the regulation of high volume hydraulic fracturing in that state. In particular, we call DEQ's attention to pages 16-19 of the report regarding groundwater quality monitoring.

Lastly, DEQ should also require that where any contaminant migration is detected as a part of concurrent or long term monitoring, any persons using the affected or potentially affected water supply should be immediately notified and provided with any relevant detection results in an easy-to-understand format.

<u>The Proposed Rules Should Require Water Testing in Response to Pollution Complaints Received After Drilling or Stimulation of a Well</u>

Water-users who observe or suspect diminution or contamination of their water supply after commencement of oil and gas operations should be able to obtain accurate and cost-free information regarding the safety and potability of their water. Although proposed R 324.1404 requires provision of baseline water quality results to nearby landowners, there is no mechanism for water users to request further testing after observing a change in their water quality or quantity, such as those which exist in other shale-bearing states.[46] In Pennsylvania, for example:

Towards a road map for mitigating the rates and occurrences of long-term wellbore leakage, Geofirma (May 22, 2014) *available at* http://www.geofirma.com/Links/Wellbore_Leakage_Study%20compressed.pdf.

[42] Maurice Dusseault et al., *Why Oilwells Leak: Cement Behavior and Long-Term Consequences*, SPE 64733 (2000) *available at* http://bit.ly/1xBGdVD.

[43] Tom Myers, *Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers*, Groundwater (2012) (concluding that contaminants from horizontal fracking wellbores may appear in aquifers in "tens or hundreds of years"), *available at* http://catskillcitizens.org/learnmore/Fracking-Aquifers.pdf.

[44] Proposed R 324.1403, 1404.

[45] The curricula vitae for Dr. Myers and Briana Mordick (cited below) are attached at Exhibit D to these comments.

[46] *See, e.g.*, Md. Code, Envir. § 14-110.1 (Maryland); 225 ILCS 732/1-85 (Illinois); 58 Pa. C.S. § 3218 (Pennsylvania); W. Va. Code § 22-6A-18(b) (West Virginia).

> [a] landowner, water purveyor or affected person suffering pollution or diminution of a water supply as a result of drilling, altering or operating an oil or gas well may so notify the Department and request that an investigation be conducted.[47]

Once a request is filed, the Pennsylvania Department of Environmental Protection must investigate the claim by taking water samples at the affected property and make a determination as to the cause of any contamination within 45 days of receiving the request.[48]

The proposed rules should provide a similar no-cost mechanism for affected water-users to request information regarding an observed contamination or diminution of their water supplies. Testing may be conducted by DEQ itself, or the Department may require testing at the expense of the oil or gas operator, such as it does with respect to noise complaints under R 324.1015(2). If testing is conducted at the expense of an operator, such testing should be conducted by an independent certified laboratory.[49]

<u>The Proposed Rules Should Require Provision of Temporary Water Where Liability for Pollution or Diminution is Determined or Presumed</u>

To ensure water contamination incidents or interruptions are addressed swiftly, a number of states have mechanisms by which oil and gas operators may be presumed liable for pollution or diminution of water supplies.[50] For example, in Maryland, within 2,500 feet of a vertical wellbore and one year of well drilling, completion, or hydraulic fracturing of a well:

> there is a presumptive impact area around the gas well in which it is presumed that contamination of a water supply was caused by the activities of gas exploration or production.[51]

These presumption provisions decrease the burdens for affected water-users seeking to obtain restoration or replacement of water supplies likely to have been contaminated or diminished by oil or gas drilling operations. These provisions are even more effective at protecting the health and property of local residents where the presumption of contamination is coupled with an obligation on the oil or gas operator to provide emergency temporary water until the affected water supply can be permanently replaced or restored.[52] To avoid unfair liability for an already contaminated water supply, the presumption of liability may be rebutted by an operator where baseline testing shows the

[47] 25 Pa. Code § 78.51(b); *see also* 58 Pa. C.S. § 3218(b).
[48] *See* 25 Pa. Code § 78.51(c).
[49] To rebut a presumption of contamination, Pennsylvania requires that operators conducting optional baseline water testing use independent certified laboratories. 58 Pa. C.S. § 3218(e).
[50] *See, e.g.*, Md. Code, Envir. § 14-110.1; 225 ILCS 732/1-85; 58 Pa. C.S. § 3218; W. Va. Code § 22-6A-18(b).
[51] Md. Code, Envir. § 14-110.1(b).
[52] *See* 58 Pa. C.S. § 3218(c.1).

water was previously of the same quality or the owner of the water supply refuses to allow baseline testing.[53]

To assure water-users in Michigan the same protections enjoyed by residents in states like Pennsylvania, West Virginia, Illinois, and Maryland, Proposed R 324.1404 should be amended, or a new section added, to include similar regulatory standards for when liability for contamination of a water supply may be found or presumed. Further, these standards should also trigger provision of an adequate temporary water supply by the operator until a permanent supply is provided or liability is disproven.[54] Although Michigan law does not have a statutory liability presumption for water contamination incidents, we believe DEQ has the authority to set regulatory standards that may recommend or necessitate a finding of liability and/or issuance of an order to provide temporary water.[55]

The Proposed Rules Should Have a Comprehensive Plan for Addressing the Large Volume of Toxic Wastewater Produced by Hydraulic Fracturing Operations

The proposed rules should create a comprehensive plan to address the substantial environmental issues posed by management and disposal of the considerable volumes of contaminated wastewater generated by hydrofracking. This wastewater is highly toxic, often containing heavy metals, volatile organic compounds, salts, and naturally occurring radioactive materials such as radium-226 and radium-228.[56] A recent study on the characteristics of hydraulic fracturing wastewater concluded that "[f]lowback water from later stage flowback from Marcellus wells contains very high concentrations of [total dissolved solids (TDS), chloride (Cl), bromine, sodium, calcium, strontium, barium, radium] and other elements. The levels of TDS, Cl and some other constituents can be 5–10 times the concentration in seawater."[57]

If mismanaged, flowback and produced water can enter and contaminate soil and water through a variety of means: via spills and leaks of the wastewater stored at the well site; by accidents during transportation of the waste by tanker truck; and through inappropriate

[53] *See, e.g.*, 225 ILCS 732/1-85(c); Md. Code, Envir. § 14-110.1(g); 58 Pa. C.S. § 3218(d); W. Va. Code § 22-6A-18(c).
[54] Pennsylvania, for example, where the presumption applies, operators are required to provide the affected water user a "temporary water supply" that "shall be adequate in quantity and quality for the purposes served by the supply." 58 Pa. C.S. § 3218(c.1).
[55] Specifically, DEQ has authority to: prevent "waste," including the "unreasonable damage to underground fresh or mineral waters," M.C.L. §§ 324.61505; 61506(a); control the pollution of underground waters of the state, M.C.L. § 324.3103; and to take action in response to an imminent and substantial endangerment to the public health, safety, or welfare, or the environment, because of a release or threatened release of a hazardous substance, M.C.L. § 324.20119.
[56] NY Draft EIS at ES-6 to ES-8; G.Allen Burton et al., *Hydraulic Fracturing in the State of Michigan: Environment/Ecology Technical Report*, Graham Sustainability Inst. 5 (Sep. 3, 2013) *available at* http://catskillcitizens.org/learnmore/HF-04-Environment-Ecology.pdf.
[57] Lara O. Haluszczak et al., *Geochemical evaluation of flowback brine from Marcellus gas wells in Pa., USA*, Applied Geochemistry (2012), *available at* http://catskillcitizens.org/learnmore/Fracking-Flowback-Brine.pdf.

or illegal disposal.[58] Practically speaking, without effective management, increases in the volume of wastewater will increase the probability and possible magnitude of contamination incidents—which is cause for concern given the potential for expansion of hydrofracking in the state. DEQ estimates that up to twenty million gallons of fresh water may go into fracturing a single horizontal well, and that typically 25% to 75% of water used in fracturing returns as contaminated "flowback" water.[59] If multiplied times the number of potential new horizontal wells in the state, the total volume of wastewater that would need to be managed could very easily reach into the billions of gallons.

While the proposed rules do address some of the concerns associated with this increased volume of wastewater—such as the general requirement that flowback fluid be stored in closed tanks[60]—more can be done. As a preliminary matter, the proposed rules can modify the definition of "flowback fluid" to include all wastewater recovered from a well until the well is ultimately plugged in accordance with Part 9 of the current oil and gas regulations, thereby also capturing what is commonly termed "produced water" or "production brine."[61] The current definition applies to all such fluids recovered until "the conclusion of test production under R 324.606," but DEQ provides no justification as to why fluids collected after such production testing should be held to less stringent regulation. Indeed, "produced water" can often contain a substantially greater variety and concentration of toxic compounds than does "flowback fluid." DEQ should also clarify that all wastewater produced from a well site—whether colloquially termed fracturing fluid, produced waters, or brine—constitutes "brine" as defined at R 324.102(f), and to the extent that it is not recycled for the purposes of future hydrofracking, must be disposed of in an underground injection well in accordance with Part 7 of the current oil and gas regulations (Part 7).[62]

DEQ should also lift the regulatory exemption for flowback fluid and other oil and gas production wastes from the state's program for disposal of hazardous wastes.[63] As described above, wastewater produced by modern hydrofracking operations is often

[58] For example, the Pennsylvania Attorney General recently brought charges against a subsidiary of ExxonMobil for illegally discharging more than 50,000 gallons of toxic waste water from a Marcellus Shale gas well site in Penn Township, PA. Pennsylvania Attorney General, *XTO Energy Inc. charged with illegally discharging waste water from Marcellus Shale gas well site in Lycoming Cnty.* (Sep. 10, 2013), *available at* http://www.attorneygeneral.gov/press.aspx?id=7191. And in Ohio, a waste hauler recently pled guilty to dumping thousands of gallons of wastewater in the Mahoning River. *Ohio man admits illegally dumping drilling waste in Youngstown case*, Timesonline (Aug. 30, 2013), *available at* http://www.timesonline.com/news/energy/ohio-man-admits-illegally-dumping-drilling-waste-in-youngstown-case/article_734e6cb3-3d34-522c-8f5c-3c2e5b7c8c8f.html.

[59] DEQ, Office of Oil, Gas, and Minerals, *Hydraulic Fracturing of Oil and Gas Wells in Michigan*, at 2, 4 (Apr. 2013), *available at* http://www.michigan.gov/documents/deq/Hydraulic_Fracturing_In_Michigan_423431_7.pdf.

[60] Proposed R 324.1405(3).

[61] R 324.901-324.904.

[62] R 324.701- 705. R 324.102(f) defines "brine" as all nonpotable water resulting, obtained, or produced from the exploration, drilling, or production of oil or gas, or both. As even the downhole fluids used in fracturing operations are non-potable, all flowback fluid should easily meet this definition.

[63] R 299.9204(2)(e) (excluding "[d]rilling fluids, produced waters, and other wastes that are associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy" from the definition of "hazardous waste.").

highly toxic, therefore exhibiting the traits that would otherwise characterize it as "hazardous waste" under state and federal law, were it not exempt.[64] Because these fluids present the same risks to human health and the environment as other substances regulated as hazardous wastes, Michiganders should enjoy, at a minimum, the same protections against their inappropriate release or disposal.

Even if DEQ does not lift the hazardous waste exemption for flowback fluids, the Department should expand Part 7 to create a more comprehensive plan for the management of oil and gas wastewater. At a minimum, this plan should:

- Require geochemical analysis of all wastewater, including methods for retesting for wastewater not immediately disposed of at appropriate intervals to determine changes in chemical composition;[65]
- Require reporting of geochemical information, as well as monthly wastewater volumes, and the method of handling and disposal for all wastewater. This information should be made publicly available on a well-by-well basis through an online, geographically based reporting system;
- Encourage the recycling of wastewater for use in future hydrofracking to the maximum extent possible;[66]
- Create a manifest system for tracking the transportation and ultimate disposal of all wastewater;
- Increase the period of time for maintaining records on the disposition of all wastewater; and
- Clarify that the prohibition of on the use of flowback fluids for ice or dust control or road stabilization purposes in proposed R 324.1405 applies notwithstanding the provisions of R 324.705, allowing the use of brines for such purposes in limited circumstances.

<u>The Proposed Rules Should Have a Comprehensive Plan for Addressing Oil and Gas Related Air Emissions that May Harm Michiganders' Health</u>

The proposed rules fail to create a framework for addressing a significant and immediate concern for Michiganders living, working, or recreating near oil and gas operations—harmful air emissions that may cause acute and/or long term health problems.

Particularly with respect to hydrofracking, a growing body of evidence is documenting air-borne pollutants at or near hydrofracking sites that are known to cause cancer and harm the nervous, respiratory, and immune systems. As described above, air emissions

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[64] *See* R 299.9208 (incorporating 40 C.F.R. §261.10).

[65] This analysis, at a minimum should include measurements for all contaminants for which EPA has set primary and secondary drinking water standards, hydrocarbons, standard inorganic ions, radionuclides, and hydraulic fracturing chemicals.

[66] For example, New York's most recent proposed regulations for hydrofracking included provisions encouraging recycling of wastewater for use in hydrofracking operations to the maximum extent feasible. See Proposed 6 N.Y.C.R.R. § 554.1 *available at* http://www.dec.ny.gov/regulations/77353.html. NRDC in no way encourages recycling of hydrofracking wastewater for other uses, such as ice management or dust suppression.

from standard hydrofracking operations have been detected at levels that pose increased risks of cancer and other health threats to those living near gas wells,[67] and correlations have been found between residential proximity to hydrofracking and higher rates of birth defects.[68] One recent comprehensive literature review identified at least fifteen different sources—including the drilling process, wastewater storage units, and condensate tanks—where air contaminants can be released during hydrofracking, concluding that "there is legitimate concern that local air pollution may produce adverse effects in individuals who live near the high emitting site or processes."[69] Another recent literature review similarly concluded "a number of studies suggest that shale gas development contributed to levels of ambient air concentrations known to be associated with increased risk of morbidity and mortality."[70] These findings appear to be consistent with "anecdotal" evidence of health problems reported by residents living in areas with high hydrofracking activity —which include headaches, nausea, nosebleeds, and, in some cases, respiratory, neurological, and dermatological problems.[71]

While the current regulations contain extensive provisions on the regulation of one common air toxic produced by oil and gas operations, hydrogen sulfide,[72] such operations produce a range of air pollutants that can harm nearby residents, workers, or passersby. Accordingly, DEQ should propose rules that create a comprehensive system for controlling emissions of and monitoring harmful air pollutants commonly produced by oil or gas operations. The pollutants addressed should include, at a minimum, the following categories:

Diesel Emissions

Diesel emissions originate from the combustion engines of heavy trucks and machinery that are used during well preparation, drilling, and production. As part of an investigation into threats to worker health, the National Institute for Occupational Safety and Health (NIOSH) expressed concern about the levels of diesel particulate matter measured at eleven oil and gas sites in Colorado, Arkansas, Pennsylvania, Texas, and North Dakota.[73] The health impacts of diesel pollution are well characterized in the scientific literature and include cancer, respiratory and cardiovascular impacts, premature mortality and adverse birth outcomes.

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[67] *See, e.g.*, McKenzie et al. (2012).

[68] *See Id.* (discussing increased cancer as well as chronic and acute non-cancer risks for residents living near hydrofracking operations); *supra*, McKenzie, *Birth Outcomes* (2014) (finding, *inter alia*, women who lived close to oil and gas wells had a higher rate of babies born with defects in their hearts than women who lived in areas with no oil and gas wells).

[69] Adgate (2014).

[70] Seth Shonkoff et al., *Environmental Public Health Dimensions of Shale and Tight Gas Development*, National Institute of Environmental Health Sciences (Apr. 16, 2004) a*vailable at* http://ehp.niehs.nih.gov/wp-content/uploads/advpub/2014/4/ehp.1307866.pdf.

[71] *See* Adgate (2014); Steinzor et al. (2013).

[72] R 324.1101-1130.

[73] Eric J. Esswein et al., *NIOSH Field Effort to Assess Chemical Exposures in Oil and Gas Workers: Health Hazards in Hydraulic Fracturing* (2012).

BTEX and Other Air Toxics

Volatile organic compounds such as benzene, toluene, ethyl-benzene, and xylene (BTEX) and other toxic hydrocarbons released during well drilling, fracturing and production can lead to health impacts ranging from mild irritation of eyes, mouth and throat to headaches, nosebleeds, aggravation of asthma and other respiratory conditions, blood disorders (anemia), immunological diseases, and cancer (e.g., leukemia, non-Hodgkins lymphoma). A health risk assessment in heavily drilled Garfield County, CO, identified many hydrocarbon pollutants (including BTEX, tri-methyl-benzenes, and aliphatic hydrocarbons) associated with increased risk of cancer and adverse respiratory and neurological effects, especially during the well completion process.[74]

Ozone smog

Hydrofracking-related processes and other stages of the oil and gas production process release nitrogen oxides and volatile organic compounds (VOCs), which react in the presence of sunlight to form ozone smog. Ozone smog is associated with a variety of respiratory and cardiovascular effects, including shortness of breath, reduced lung function and aggravation of asthma and chronic respiratory disease symptoms, inflammatory processes, and premature death.[75] A growing number of studies have attributed emissions of ozone precursors from rapidly growing oil and gas development[76] to significantly elevated ozone concentrations in Wyoming,[77] Colorado,[78] Utah,[79,] Pennsylvania,[80,] Texas,[81,] and Oklahoma.[82]

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74 McKenzie et al. (2012).

75 U.S. EPA, *Health Effects of Ozone in the General Population* (2014), *available at* http://www.epa.gov/apti/ozonehealth/population.html.

76 Christopher Moore et al., *Air Impacts of Increased Natural Gas Acquisition, Processing, and Use: A Critical Review*, 11 Envtl. Sci. & Tech. (2014), *available at* http://biology.duke.edu/jackson/est2014a.pdf.

77 Wyo. Dep't of Envtl. Quality, *WDEQ Winter Ozone Update*, Public Meeting, Pinedale, Wyo. (Mar. 22, 2011).

78 Gabrielle Pétron et al., A New Look at Methane & Non-Methane Hydrocarbon Emissions from Oil & Natural Gas Operations in the Colo. Denver-Julesburg Basin, Journal of Geophysical Research (2014) abstract available at http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract.

79 Helmig et al. (2014); Seth Lyman & Howard Shorthill, *Final Report: 2013 Uintah Basin Winter Ozone & Air Quality Study*, Utah State Univ. (Sep. 30, 2013) *available at* http://rd.usu.edu/files/uploads/ubos_2011-12_final_report.pdf; P.M. Edwards et al., *Ozone Photochemistry in an Oil & Natural Gas Extraction Region during Winter: Simulations of a Snow-Free Season in the Uintah Basin, Utah*, Atmospheric Chemistry & Physics 13:8955-71 (Mar. 20, 2013), available at http://www.atmos-chem-phys.net/13/8955/2013/acp-13-8955-2013.pdf.

80 Anirban A. Roy et al., *Air Pollutant Emissions from the Dev., Prod., & Processing of Marcellus Shale Natural Gas*, Journal of the Air & Waste Mgmt. Ass'n 64 (1): 19-37 (Jan. 2014), *abstract available at* http://www.tandfonline.com/doi/abs/10.1080/10962247.2013.826151#.U9lhgvldVkg.

81 Susan Kemball-Cook et al., *Ozone Impacts of Natural Gas Dev. in the Haynesville Shale*, Envtl. Sci. & Tech. 44 (24): 9357-63 (2010), *available at* http://1.usa.gov/XjKd28; Eduardo Olaguer, *The Potential Near-Source Ozone Impacts of Upstream Oil & Gas Indus. Emissions*, Journal of the Air & Waste Mgmt. Ass'n 62 (8): 966-77 (2012), *available at* http://bit.ly/1txPzUK.

82 A.S. Katzenstein et al., *Extensive Regional Atmospheric Hydrocarbon Pollution in the Sw. United States*, Proceedings of the Nat'l Acad. of Scis. 100 (21): 11975-79 (2003) *available at* http://www.pnas.org/content/100/21/11975.full.

Silica

Silica, or 'frac sand', is used widely and in large quantities to hold open the fractures created during the hydrofracking process. Inhalation of silica is known to cause the irreversible lung disease silicosis as well as lung cancer in miners, sandblasters, and foundry workers. Silica inhalation is now also a recognized health hazard among oil and gas workers: researchers at NIOSH collected one hundred eleven personal breathing zone samples at eleven sites in five states and found that at each of the sites, full-shift samples exceeded standards set to protect workers.[83]

The Proposed Rules Should Encourage Reduction of Leaked or Vented Methane

In addition to developing rules for control of air pollutants which may cause immediate or long-term health impacts, DEQ should adopt available and reasonable cost measures for reducing waste in the form of leaked and vented methane, a major contributor to climate change. As a greenhouse gas, methane is twenty-five times as potent then carbon dioxide on a one hundred year time scale and seventy-two times more potent on a twenty year time scale.[84] Further, according to the 2014 Greenhouse Gas Inventory published by the U.S. Environmental Protection Agency (EPA), the oil and gas sector is the largest source of anthropogenic methane emissions in the country.[85] There are currently no federal regulations requiring control of methane from the oil and gas sector, so such state standards would not exceed any federal rules or standards.

EPA's New Source Performance Standards (NSPS) for volatile organic compounds (VOCs) from the oil and gas sector, adopted in 2012,[86] will result in some methane reductions as a co-benefit of the VOC requirements, but they fail to address large quantities of wasted methane from this sector. The shortfall on methane control results because the 2012 NSPS do not reach (a) sources where methane emissions are high but VOC emissions low, such as in segments downstream of natural gas processing plants, or (b) existing equipment that emits methane.[87] Thus there remains a significant methane waste problem for the state to address.

To address the problem of leaked or vented methane DEQ should promulgate rules that encourage reduced emissions completions (RECs) at well sites—including coordination of drilling and well completion operations with gas line installation—and require natural gas operators to install methane emission controls on gas dehydrators, unless technically infeasible. Further, DEQ should promulgate rules that regulate the use of pneumatic

[83] Eric Esswein et al., *Occupational Exposures to Respirable Crystalline Silica during Hydraulic Fracturing*, Journal of Occupational and Environmental Hygiene 10 (7): 347–56 (Jul. 1, 2013) *available at* http://digitalcommons.unl.edu/cgi/viewcontent.cgi?article=1280&context=publichealthresources.

[84] Intergovernmental Panel on Climate Change, *Direct Global Warming Potentials: Table 2.14* (last accessed Jul. 30, 2014) http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

[85] *See* U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions & Sinks, 1990-2012*, Chapter 3, "Energy," (Apr. 2014), *available at* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Chapter-3-Energy.pdf (total for the oil and gas sector is derived through summing methane figures for "natural gas systems" and "petroleum systems").

[86] *See* 40 C.F.R. §§ 60.5360-60.5430.

[87] *Id.*

controllers at oil or natural gas production facilities, natural gas gathering or transmission compressor stations, or natural gas processing plants and set standards for leak detection and repair at well production facilities and natural gas gathering and transmission compressor stations. Regarding these last points, we attach recommended regulatory language at Exhibit B to these comments.

The Proposed Rules Should Address the Potential for Induced Seismicity from Well Stimulation

The proposed rules fail to address harms that may arise from the potential for induced seismicity (i.e., man-made earthquakes) resulting from well-stimulation or fracturing. Hydrofracking has been confirmed or is suspected as the cause of induced seismicity strong enough to be felt at the surface in a number of incidents, and seismic activity has also been linked to underground injection of hydrofracking wastewater. To highlight the concerns with induced seismicity from hydrofracking and identify regulatory steps DEQ may take to address them, we attach comments prepared by NRDC staff petroleum geologist Briana Mordick at Exhibit C to these comments, which were earlier submitted as part of technical comments on proposed amendments to Pennsylvania's regulatory code regarding the regulation of oil and gas operations. These comments have equal relevance in Michigan, particularly considering that, like Pennsylvania, Michigan has not assumed primacy for implementing its underground injection control program pursuant to the federal Safe Drinking Water Act.

DEQ Should Create an Easily and Publicly Accessible Web Platform for Submission and Publication of Oil and Gas Well Information

DEQ should create an easy-to-use, publicly-available internet platform to collect and disseminate important information regarding oil and gas activities—such as documents submitted for well applications, inspection reports, and well closure information. Creation of such a web platform would facilitate agency analysis and enforcement and provide Michiganders with access to critical information about oil and gas activities occurring in their communities.

While DEQ does currently provide information about oil and gas activities electronically, this information is spread out among a variety of sources with differing interfaces,[88] some of which are difficult to use, and certain information—such as violation or inspection information—still remains unavailable.

DEQ now proposes to require applicants to submit information regarding chemical additives used in hydraulic fracturing operations to another website, the FracFocus

[88] For example oil and gas well information is spread out between DEQ's GeoWebFace Portal (http://www.michigan.gov/deq/0,4561,7-135-3311_60700---,00.html), the Michigan Online Oil and Gas Information System (http://ww2.deq.state.mi.us/mir/), various pages on the DEQ website (see, e.g., http://www.michigan.gov/deq/0,4561,7-135-3311_4111_4231-262172--,00.html), and mineral leasing information maps kept on the Michigan Department of Technology, Management, and Budget website (http://www.michigan.gov/cgi/0,4548,7-158-52927_53037_12540_13817_13818-30992--,00.html).

Chemical Disclosure Registry.[89] While disclosure of this information to FracFocus is better than none at all, DEQ should also increase transparency regarding its regulation of oil and gas activities by creating a centralized, easy-to-use web platform that, at a minimum, makes the following information readily available to the public:

- All well application information—including information regarding water withdrawals and groundwater baseline water sampling information;[90]
- Information associated with conformance bonds, required under R 324.206;
- Requests for modification of permits or well status and information associated with change of ownership, and the disposition of any requests;
- All information associated with voluntary or statutory pooling, including any requests for or issuance of pooling orders;
- Information submitted to DEQ regarding activities at the well site, such as drilling and cement logs, the reporting of serious accidents, or the required submissions under proposed rule R 324.1405 regarding hydraulic fracturing;
- All inspection reports;
- All investigation reports of spills, leaks or other accidents, and all notices of violation issued for oil and gas activities;
- Waste disposal information;
- Well closure information.

Complete and easy-to-access information about oil and gas activities is important to ensure the maximum effectiveness of state regulation and accountability, and it is critical to Michiganders living next door to oil and gas activities who wish to understand and take precautions against the potential harms of those activities.

Conclusion

As discussed above, significant work remains to be done to evaluate the risks posed by hydrofracking before it can be determined if and how best the activity should be allowed proceed in Michigan. Accordingly, NRDC urges that DEQ avoid rushing forward in permitting an understudied and broad-ranging industrial activity before this critical research and analysis can be performed.

To the extent, however, that DEQ insists continuing to permit hydrofracking operations—knowing fully that it has an incomplete understanding of the potentially significant risks that hydrofracking poses to citizen health, property, and welfare as well as the integrity and vitality of the state's communities and natural resources—NRDC strongly advises that DEQ, at minimum, correct the substantial deficiencies in its current and proposed rules, identified above, as expeditiously as possible. Without these changes, Michigan will far short of being a leader on hydrofracking policy and fail to

[89] Proposed R 324.1406(1).
[90] With appropriate redactions as necessary to protect the private information of landowners who have allowed baseline testing at their property.

codify many currently available protections enjoyed by residents of other states, and which all Michiganders deserve.

Respectfully Submitted,

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EXHIBIT A

Technical Memorandum

Review and Analysis

Revised Draft

Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

September 2011

January 5, 2012

Prepared for:

Natural Resources Defense Council

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Contents

INTRODUCTION

This technical memorandum reviews aspects of the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) on the *Oil, Gas and Solution Mining Regulatory Program regarding Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoir*. The New York State Department of Environmental Conservation (NYSDEC) is the lead agency. Throughout this review, I refer to the document as the RDSGEIS. The document was "revised" since its initial publication in 2009. I had prepared a review of the 2009 DSGEIS as Myers (2009).

Appendix A to this technical memorandum is my specific review of Appendix 11 in the RDSGEIS, which has been excerpted from the 2009 DSGEIS without change. Appendix B to this technical memorandum is a paper I wrote which is currently undergoing peer review for a journal; this paper concerns vertical transport of contaminants from the shale to freshwater groundwater.

Since the 2009 DSGEIS, the New York State Energy Research and Development Authority (NYSERDA) contracted with Alpha Geoscience (Alpha) to review the comments I prepared on the 2009 DSGEIS (Myers, 2009). Alpha produced a report titled: *Review of dSGEIS and Identification of Best Technology and Best Practices Recommendations, Tom Myers: December 28, 2009*, prepared by Alpha. The RDSGEIS does not reference, or apparently rely, on this Alpha review in any meaningful way; the bibliography includes a list of 2011 reports by Alpha, but the apparent reference to this review (Alpha 2011) does not include my name. The consultants bibliography includes a subheading with Alpha's report, with "Myers" misspelled, but no apparent use of this reference either. Alpha's reviews prepared for NYSERDA were not available directly on the RDSGEIS web page other than through an obscure link. Appendix C to this technical memorandum is my response to Alpha (2011).

This technical memorandum also reviews the water resources/hydrogeology aspects of the revised regulations, published as *Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560, Subchapter B: Mineral Resources*, referred to throughout as the proposed regulations. This technical memorandum proposes additional regulations throughout the review, and then includes a separate section regarding specific proposed regulations.

The report focuses on three main aspects of the RDSGEIS: (1) hydrogeology, including the hydraulic fracturing (fracking) process, (2) low flow surface water resources, and (3) water-resource-related setbacks. Hydrogeology includes review of the geology, contaminant transport, shale hydrogeology, groundwater quality, and induced seismicity analyses. Low flow

surface water resources include an assessment of the analysis required to determine passby flows and the requirements/restrictions on pumping from aquifers. Consideration of the proposed setbacks includes whether the proposed setback is based on facts or analysis. Specific setbacks considered include those proposed to protect aquifers, wells, springs, and other water-related resources.

The RDSGEIS provides data and analysis almost exclusive to the Marcellus shale, although the regulations purport to govern all low-permeability formations, including the Utica shale (which is mentioned in the RDSGEIS). Developing different low-permeability formations would have different effects than would development of the Marcellus shale, which is the focus of the RDSGEIS. Deeper shale, such as the Utica shale, would generate far more cuttings and use more drilling mud, which present different disposal issues. The amount of water used for fracking could be different, as well. Development of shallower shales would increase the regional hydrogeology impacts and increase the potential vertical contaminant transport and the prevalence of improperly plugged abandoned wells. Additionally, the RDSGEIS focused its analysis from the total amount of surface water withdrawals to wastewater disposal on the wells expected in the Marcellus shale. Additional shale development would vastly increase the impacts beyond those revealed in this RDSGEIS

- *The RDSGEIS and proposed regulations should acknowledge that they apply only to the Marcellus shale.*
- *Additional low-permeability gas plays require additional supplemental GEIS analyses as suggested in RDSGEIS 3.2.1*.

The focus on this review is on development of the Marcellus shale, because except for Chapter 4, the RDSGEIS discussion is limited to the Marcellus shale.

SUMMARY OF FINDINGS

The RDSGEIS only poorly describes the hydrogeology of the Marcellus shale area and of the shale in particular. It does not provide a description of what fracking does to the shale or how it affects the regional hydrogeology. There is no description provided of the geologic formations between the shale and the surface beyond the general stratigraphy and stating that it would be nonconductive to upward flow, a point not supported with data or by the literature. The fault mapping is outdated.

Industry should be required to complete geophysical logging, including conductivity, to determine the lower extent of freshwater (Williams 2010). The definition of freshwater should

be as protective as federal standards, meaning that surface casing should extend to TDS at 10,000 ppm.

The description of fracking is incomplete and incorrect from a hydrogeologic perspective. The contention that out of formation fracking is rare is incorrect based on industry data which has documented fractures as much as 2000 feet above the top of the shale in other states. Also, the contention that fracking pressure dissipates immediately upon cessation of injection is also incorrect, except right at the well. Model simulations show that pressure in the shale remains elevated for more than three months and that that prevents some of the injected fluid from flowing back to the gas well. The injected fluid displaces substantial amounts of formation fluid from the shale into surrounding formations; existing and new fractures allows that fluid to move much further from the shale than expected due simply to the volume injected.

The RDSGEIS dismisses the concept of contaminant transport from the shale to the near-surface aquifers, but there is overwhelming evidence that it is at least possible. Fracking fluids and methane have been found in water wells from fracking in different areas. Simulations indicate it could occur much more in the future. Fracking displaces large quantities of brine, and fractures provide pathways to the surface; fracking may also widen those existing pathways. Areas of natural artesian pressure would allow advection to move fluids and contaminants vertically upward. Mapping areas of artesian pressure, improved regional fault mapping, and site-specific project by project fault mapping should be employed to avoid areas of enhanced vertical transport potential. Long-term multilevel monitoring is also needed to track the future potential of vertical contaminant movement.

NYSDEC proposes setbacks that are not obviously based on observed data. If the setback from fracking in a protected watershed is 4000 feet, the setback from primary or principal aquifers or from public water supply wells should be no less, unless justified by site-specific analyses. Wells located in a 100-year floodplain have a greater than 1 in 4 chance of being flooded in a 30-year project life, therefore wells should be setback further from streams.

The proposed monitoring plans are paltry and insufficient. Simply monitoring existing water wells only shows when that user is affected, it does not protect the aquifer. Water wells are not designed for monitoring. The industry should establish a dedicated groundwater monitoring system downgradient from every well pad, out to at least the distance that a contaminant would travel in five years. Monitoring should continue for at least five years after the cessation of production.

The required passby flows have improved since 2009, as has the method for determining them. In general requiring the Q60 and Q75 monthly flow avoids diversions at all when flows are in the bottom 40 or 25 percent of their normal monthly flow regime, depending on area and

month. Q75 only applies to larger streams (> 50 square mile watershed) during the winter months when flow is generally higher. The RDSGEIS should provide some data to show the estimation methods for ungaged sites is accurate.

HYDROGEOLOGY

This section considers all aspects of the RDSGEIS that concern underground resources, including aspects of geology, shale hydrogeology, contaminant transport, the descriptions of fracking and the potential for fracking-induced seismicity. The toxicity of fracking fluid additives was considered was considered by Dr. Glenn Miller.

General Hydrogeology

The distinction between primary and principal aquifers and other sources (RDSGEIS, p. 2-20) ignores the connections between surface and groundwater. Groundwater from principal aquifers may seep into streams, especially during periods of low flow. Because those aquifers are also used by New Yorkers for water supply, the assertion in the RDSGEIS that "one quarter of New Yorkers … rely on groundwater as a source of potable water" (Id.) understates the number of people who may be affected by groundwater contamination

RDSGEIS Figure 2.1 shows that the north end of the shale parallels a large principal aquifer north of Syracuse. This coincidence deserves explanation at some point in the document.

The RDSGEIS mentions that one quarter of New Yorkers rely on groundwater as a source of potable water (RDSGEIS, p. 2-20). This downplays the connection of groundwater with surface water; many aquifers support stream flow, especially during low flow period, therefore aquifer contamination potentially affects many more people.

Safe yield (RDSGEIS, p. 2-29) is an outdated and flawed concept which should not be repeated in the RDSGEIS. It is flawed because all pumping depletes the aquifer, which contradicts the definition of the phrase (Id.). The preferable concept is sustainable yield which is the amount of water that can be pumped without having significant negative effects on the aquifer and on resources connected to that aquifer; what is significant is a societal question related to the values that depend on the aquifer (Alley et al, 1999).

Presence of Fresh and Salt Water

The federal Safe Drinking Water Act (SDWA) defines an underground source of drinking water (USDW) as "[a]n aquifer or portion of an aquifer that supplies any public water system or that

contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer" (http://water.epa.gov/type/groundwater/uic/glossary.cfm). However, NYSDEC apparently ignores this federal requirement where it specifies that surface casings be extended to 75 feet below the transition from fresh- to saltwater but also specifies 850 feet below ground surface (bgs) as a "practical generalization for the depth to potable water", the point at which near-surface freshwater transitions to saline water, which corresponds to 1000 ppm total dissolved solids (TDS) and 250 mg/l chlorides (RDSGEIS, p. 2-23, 6NYCRR §550(at)). The NYSDEC regulations, by only protecting water to a 1000 ppm cutoff for TDS may not provide protections that for some waters that could apparently meet the definition under the SDWA.

The hydrogeology of southern New York over the Marcellus gas play does suggest that there may be very little water with a TDS higher than the threshold that could actually be developed. Williams (2010) found that freshwater transitions to salt water at about 200 feet bgs in valley areas and about 800 ft bgs in upland areas in three counties in the middle of the Marcellus shale gas play. There was uncertainty around the depth estimates with some freshwater observations at deeper depths. Also the distinction between fresh- and saltwater in his survey of both water and gas wells was based on taste tests rather than any scientific measurement. Williams et al (1998) found similar results in similar geology just across the border in Pennsylvania. Many electric conductivity logs for bedrock water wells in the north Catskill Mountains (Heisig and Knutson 1997) showed that EC would jump from low values representing freshwater to high values representing salt water in a short transition zone or threshold. This suggests that many of the bedrock areas over the Marcellus shale gas play have either high-quality, low-TDS water, or very poor-quality high-TDS water; few wells apparently have water quality near the actual cut-off value. Considering the geology of the area, the zones that have high TDS are also mostly very low hydraulic conductivity zones, so they would not be considered an aquifer because they would not produce sufficient water to support a water supply.

However, the presence of salt water welling up under the alluvial aquifers, which often coincides with fault zones, suggests that salt water does move upward in fractured areas. Water with TDS up to 10,000 ppm may be developable in these higher conductivity fracture zones. In these areas, the NYSDEC regulations may be violating the SDWA requirements to protect USDWs, although the regulations regarding development in primary and principal aquifer may limit drilling in the areas underlain by fractured rock which could have developable high TDS water. Regardless of those aquifer regulations, the threshold for protection should include all areas that qualify as underground sources of water as defined under the Safe Drinking Water Act. These would include waters with TDS up to 10,000 ppm where they exist in an aquifer, and to 1000 ppm or

250 mg/l Cl- in areas underlain by unconductive bedrock. See the separate technical review submitted by Harvey Consulting LLC, for further discussion of the requirements on the SDWA.

- The operator should extend the surface casing to below the 10,000 ppm TDS threshold, unless the operator can show that the formation containing groundwater between 1000 and 10,000 ppm could not produce water in usable quantities. In this case, the operator should extend the surface casing to below the 1000 ppm TDS threshold.

The RDSGEIS does not indicate that the regulations will require the driller to actually locate the transition depth, which would define the depth below which the surface casing would extend a minimum of 75 feet (RDSGEIS, p. 7-50).

- *The regulations should require the operator to complete geophysical logging, including specific conductance logging, prior to casing the well, to determine the actual depth of protected water to which to apply the casing regulations.*

Hydrogeology of the Shale

RDSGEIS Section 4.0 covers Geology, but leaves out most of the important aspects of the Marcellus shale. There is no discussion of hydrogeology of the formations between the targeted shales and the surface, including no discussion of the hydrogeology of the shale itself beyond mention of the permeability. This failure means there is no baseline against which to compare the hydrogeologic changes caused by fracking. There is no hydrogeologic description of the sedimentary layers between the shale and the surface other than very cursory mentions of how it has low permeability. The lack of data on the hydrogeology of formations between the target shale and ground surface is important because NYSDEC relies on geology to “limit or avoid the potential for groundwater contamination” (RDSGEIS, p. 6-2).

Formations that lie between the shale and the surface are generally considered a natural control on fracture propagation and contaminant transport vertically from the shale (RDSGEIS, p. 6-54). RDSGEIS Figure 4-2 does not support the statement that overlying formations will prevent vertical movement of contaminants (RDSGEIS, p. 6-54) because it shows that layers above the Marcellus are primarily sand, limestone, and shale, with no indication of the proportion of each, which controls their conductivity and their propensity to propagate fractures. Most important from the perspective of contaminant transport from the shale to the surface is the prevalence of fractures, both due to faults and otherwise. Faults could be a pathway for vertical contaminant transport (Osborn et al 2011; Myers in review) and could also allow fractures to propagate further from the shale. The RDSGEIS discusses faults only with regard to present day seismicity and the potential for induced seismicity and presents an outdated map (Isachsen and McKendree 1977). A more detailed an integrated analysis of faults and fractures revealed there are many more faults in New York’s Appalachian Basin than

previously suspected (Jacobi 2002). The RDSGEIS should include up-to-date information and acknowledge that more faults are probably yet to be found.

There is little information provided in the geology or hydrogeology sections about the make-up of the shale, beyond the amount of organic carbon. The geology chapter does not even mention the presence of pyrite in the Marcellus shale, although there is a brief reference to it for the Utica shale. The sections on "Solids Disposal" mentions pyrite and acid rock drainage of cuttings derived from the Marcellus shale. "As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral), there exists the potential that cuttings derived from this interval and placed in reserve pit may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD)" (RDSGEIS, p 7-67). ARD will be discussed more below in the Regulations section.

Most industry references state the Marcellus shale is "low-permeability" (RDSGEIS, p. 2), and the proposed regulations apparently rely on this categorization, although not all sources agree with it. Soeder (1988) described Marcellus shale as "surprisingly permeable" and presented data showing the permeability ranges up to 60 microdarcies, as compared to the Huron shale with permeability two orders of magnitude lower. Most reported permeability values are estimated from core samples, but, in a hydrogeologic sense, these estimates do not represent the formation-wide conductivity; point estimates due to scaling effects can be several orders of magnitude less conductive than the formation as a whole due to preferential flow through fractures (Schulze-Makuch et al, 1999), which are prevalent in this area. RDSGEIS Figure 4-2 also does not show the fractures in the overlying formations which prevail throughout New York including in the Marcellus shale zone (Myers in review).

The assertion that the shale requires fracturing "to produce fluids" (Id.) does not prove that the shale above the Marcellus is equally poorly transmissive. Shales above the Marcellus have not apparently trapped gas or fluids for significant time periods, a fact which undercuts the claim they are not transmissive or there is a lack of vertical flow. Fractures that go out-of-formation above the shale connect the shale with the much more transmissive formations above the shale.

The Geology section should also discuss general groundwater flow paths in the formations above the shale; this should include vertical gradients and recharge zones.

- *The RDSGEIS should discuss the hydrogeology of the formations between the targeted shale and ground surface, including data on the hydraulic conductivity of the formations.*

- *The RDSGEIS should also map the groundwater gradients for the formations just above the targeted shale using water level data obtained from geothermal applications and previous deep wells.*
- *The NYSDEC should require the industry to do a seismic survey to locate faults near proposed drilling, within half a mile of the center of the well pad or 1000 feet beyond the projected end of the horizontal wells, whichever is further from the well pad.*
- *The RDSGEIS should include up-to-date fault mapping.*
- *Industry should be required to complete and provide to the NYSDEC geophysical logging of the formations above the targeted shale showing fractures, lithology, and groundwater characteristics.*

Description of Hydraulic Fracturing

RDSGEIS Chapter 5 describes the fracking process, but it does not describe what actually happens to the shale – what does it look like after fracking and what are its properties. It is much more permeable to gas flow, perhaps substantially so, therefore it must also be much more transmissive to water flow. With up to an expected 40,000 horizontal wells over the next 30 years in New York (RDSGEIS, p. 6-6), the properties of the shale, which currently is an aquitard, will change substantially. The RDSGEIS completely fails to address these changes.

Industry designs fracking jobs to keep the fractures in the shale, but data show that the results of the fracking do not always or even often verify the design. The industry rarely monitors or measures the actual extent of fractures (RDSGEIS, p. 5-88), beyond monitoring pressure and injected fluid during fracking. The RDSGEIS references Fisher (2010) as being proof that fractures do not extend into the aquifer zone, but his data actually show that fractures commonly go out of formation (Figure 1). His data show many instances of the top of the fracture zone being more than 1000 feet above the centerline of the shale. As the depth to the centerline of the shale decreases from 8000 to 5000 feet, the vertical fracture growth also appears to decrease from 2000 feet above to 500 feet above the centerline of the shale. The apparent trend to fracture growth above the formation decreasing with decreasing depth may relate to the pressure on the rock or its hardness. The data were not sorted according to formation type and there is no data concerning shale thickness, therefore it is unknown whether fractures extend further in some types of rock or whether out-of-formation fractures are more common with thinner shales.

- *The RDSGEIS should not rely on industry's alleged intent to avoid out-of-formation fracking as a means of preventing the consequences of out-of-formation fracking.*

- *The RDSGEIS and regulations should require geophysical logging and microseismic tests to map how far fractures extend out of formation, and the density of the fractures in different formation. This information should be publically available so that all companies can benefit from experience and so that the public can better understand the process.*

FIGURE 2

Marcellus Shale Mapped Fracture Treatments (TVD)

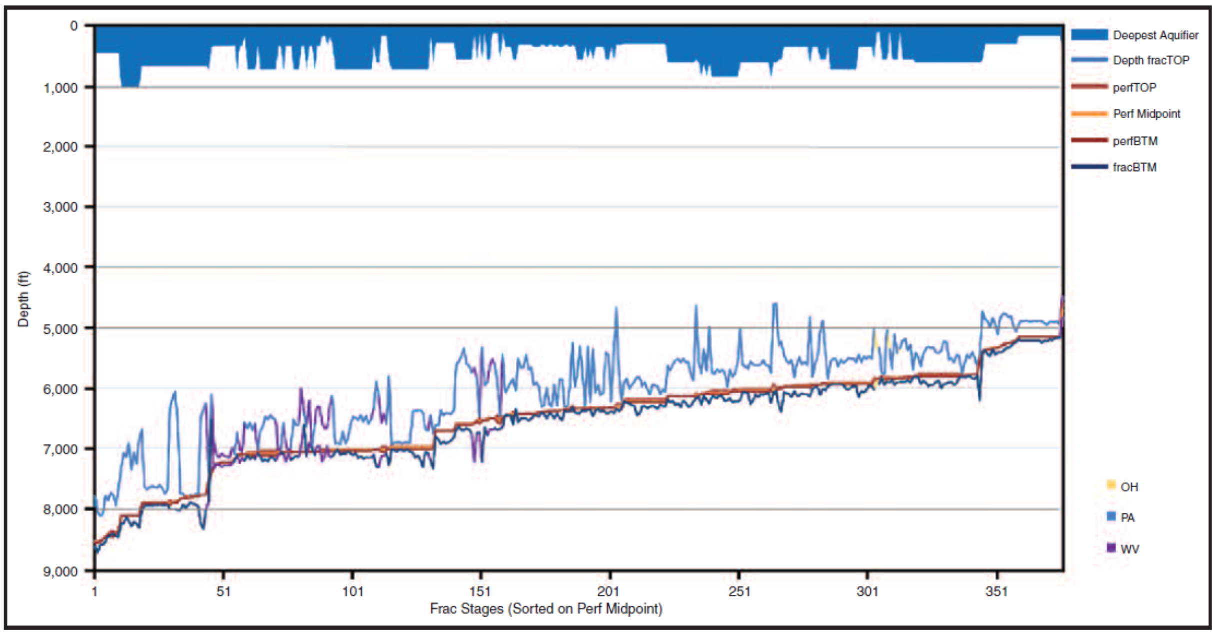

Figure 1: Figure 2 from Fisher (2010) showing the well centerline and a depth to the top of the fracture zone.

It is common practice to compare pressure and flow rate monitoring results from fracking operations to expected values from pre-fracking modeling as a method for evaluating the results of a fracking procedure (RDSGEIS, p. 5-88). Considering that many things affect the pumping flow rate, including pores between the well and the leading extent of the fluid moving away from the well, hydraulically it is difficult to imagine that a significant pressure drop would accompany the leading edge of the fluid reaching surrounding formations. Fracturing into surrounding formations would not bring additional water into the shale, as suggested (Id.), because of the pressures as described elsewhere (Myers in review). The increased porosity in the shale would release substantial brine bound in the shale.

Fracking injects up to 7.2 million gallons of frack fluid into the shale over a well bore up to 4000 ft long – the RDSGEIS suggests these are general upper limits based on fracking in the Marcellus shale in other states. Fractures form or widen as the injection pressure exceeds the normal stress in the shale (RDSGEIS, p. 5-95). The injection would slowly displace any water and gas

that exists in the (extremely small) pore spaces near the well; it would push the natural fluid away from the well bore. Because less than 35% of the injected fluid returns to the well as flowback, a significant proportion of the injected fluid remains underground, presumably occupying pores extending out from the well bore. Assuming a job injects 5 million gallons and there is 20% flowback, approximate average values, and 10% effective porosity resulting from the fracking, the fluid could occupy all pore spaces in a 21-ft diameter cylinder centered on the well. Assuming a more realistic resulting effective porosity of 1%, the fluid could fully occupy the pores out to 62 feet in all directions from the well. Fluids that existed there prior to fracking would be pushed further from the wellbore, likely into surrounding formations. Thus, simple consideration of the volume of fracking fluid injected shows that fluid would move far from the well bore and displace formation fluids even further The calculation does not account for pre-existing preferential flow paths or heterogeneities in the direction that fractures develop, so the fluid would likely move further from the well bore in some directions. The fluid would also follow pathways created by the fractures above the shale, thus fluids could end up much further from the well bore than simple considerations would indicate. .

Shale NG development will affect a large proportion of the shale in New York with fracking fluid, as can be shown by comparing expected fracking fluid volumes with shale volume. The RDSGEIS does not indicate the total area of Marcellus shale within New York. However, Figure 2 in Myers (in review) shows the extent of shale within New York to be 18,680 sq miles. Assuming an average thickness of 100 ft, the total volume is $5.2\text{x}10^{13}$ ft^3. If the expected 40,000 wells are all developed in the Marcellus shale, the injected water volume will approximate $2.1\text{x}10^{10}$ ft^3, which at porosity of 0.01 means that fracking fluid would occupy all of the pores in about 4% of the total Marcellus shale volume[1]. This assumes that none of the fluid reaches surrounding formations, which as shown above is unlikely. It is also unlikely that development will be evenly spaced over the shale as supposed in this calculation, therefore the effect in areas of concentrated development could be underestimated.

Fracking efficiency does not improve if the well spacing is significantly less than 300 m, or about 1000 ft (Krissane and Weisset 2011). It is therefore appropriate to assume that fracking changes the shale over the entire spacing unit, or an area of 660 by 4000 ft. The total area affected by 40,000 wells would be about 3800 square miles, which is about 20% of the total shale area in New York. Based on the extent that injected fluid reaches from the well and the frequency of out-of-formation fracturing (Fisher 2010), it is reasonable to conclude that most fracking affects the shale to its edge. Fracking, based on these assumptions, will significantly change the hydrogeology over at least 20 % of a shale aquitard that extends over 18,680 square miles of New York. Because not all of the total area will be developed, it is a good assumption

[1] This calculation assumes 5,000,000 gallons injected per well and 20% flowback for each of 40,000 wells.

that where development actually occurs, fracking will substantially change the shale hydrogeology.

The statement, that "the volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer" (RDSGEIS, p. 6-53), is also misleading. The total proportion of pores actually filled by injected fluid may be relatively small, but combined with displaced existing brines the injection will affect groundwater over a much larger proportion of the pores. The boundary between salt and freshwater may be displaced or disrupted by advection and dispersion of and by fluids associated with fracking. Additionally the changed properties of the shale over a large area will affect the upward movement of the natural brines. Simple consideration of advection and dispersion shows that the current balance between fresh and salt water could be substantially upset by fracking.

The RDSGEIS also erroneously claims that the pressure applied for injection will dissipate immediately upon cessation of pumping; in the well bore that may be correct, but the fact that pressure exists to push fluid back into the well bore proves that residual pressure remains in the shale and possibly beyond. The statement that "the amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock" (RDSGEIS, p. 5-94, p. 6-53) is technically correct but highly misleading because pressures and conditions for transport from the shale to the near surface will exist long after fracking has finished. Fluids can move away from the well bore at distances from the well bore after the injection ends until the pressure has dissipated; the contrary statement (RDSGEIS, p. 5-94) is wrong in that respect. Myers (in review) describes the modeling of injection and its effect on the pressure distribution in detail. The following is a simpler and more accurate description that should be what appears in the RDSGEIS:

> Hydraulic fracturing involves high pressure injection of fracking fluid into the shale from a horizontal well. This injection fractures the shale and increases the size and connectivity of existing pores. The high pressure creates a pressure gradient from the well to a point in the shale just beyond the expanding volume of injecting fluid where the pressure remains equal to background. If the fluid disperses from the well evenly, the volume will be a cylinder. As injection continues, the radius of the cylinder increases and pressure gradient is from the well to the edge of the cylinder. Offsetting the decreased pressure gradient is an increased effective cross-sectional area for the fluid to cross. The flow away from the well fractures the shale, creating new fractures and increasing the size of the existing fractures. When injection ceases the pressure in the well drops immediately to atmospheric pressure coincident with the well-bottom depth. However, the pressure in the shale begins to drop more slowly, initially equals that caused by injection. Flow away from the well continues as the pressure in the reservoir

created by the HVHF treatment moves fluids towards the well and away from the well both but since there is no more pressure being applied at the well the pressure in the shale near the well begins to drop.

Descriptions in the RDSGEIS (p 5-94) are therefore wrong. Fracking is a transient situation wherein a pressure divide, where the pressure is higher between the well and the end of the fluid, sets up with some fluid movement toward the well and some away from the bore continues. The modeling (Myers in review) shows that this requires about 90 days to effectively dissipate. This counters several statements in the RDSGEIS implying that all fracturing and flow from the well bore ceases at the end of fracking, in about five days.

The claim that the flow direction away from the wellbore would be reversed during flowback (RDSGEIS, p. 6-54) also cannot be correct if only 10 to 30% of the injected fluid actually returns to the well. Some must continue to flow away from, or at least not toward, the well.

NYSDEC makes an unreasonable assumption regarding the flow around the shale after fracking, regarding a discussion of the period between fracking operations if refracking would occur. "It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore" (RDSGEIS, p. 5-99). Because the goal is to attract gas from the shale, any such low pressure would likely affect just the fracked shale, not formations away from the shale in which fluids would flow according to the background hydraulic gradient. That a small amount of formation water may be produced with time indicates that water from only a small portion of the shale near the well flows toward the well. If the natural gradient in formations above the shale has a vertical component, there will be upward advection of water and contaminants away from the shale.

- *Measurements of the water pressure profile should be made in each well prior to fracking, as it is drilled and before it is cased. This could be a part of the geophysical logging process*.

NYSDEC assumes that it will be rare for a well to be refracked, that is, to repeat the fracking operation years after initially completing it, inappropriately relying on "Marcellus operators'" assurances without reference to a source (RDSGEIS, p. 5-98).

Contaminant Transport from the Shale

The RDSGEIS completely dismisses the concept of vertical contaminant migration from the shale to fresh-water aquifers. Statements suggesting that the only way for the public to be exposed to fracking fluid would be through an accident or spill (RDSGEIS, 5-74) reflect the

dismissal of the potential long-term transport from the shale. This section reviews the evidence and potential for contaminant transport from the shale.

Claiming that regulatory officials from 15 states have "testified that groundwater contamination as a result of the hydraulic fracturing process … has not occurred" (RDSGEIS, p. 6-41 & 6-52) is misleading because they have simply never looked for contamination beyond reports from water well owners. There are no monitoring well networks designed to monitor contaminant transport upward from the fracked shale. The upward transport could also take years, decades, or centuries, not just the few days considered in the RDSGEIS. They are wrong to suggest there is no evidence for such transport.

Two reports have documented or suggested the movement of fracking fluid from the target formation to water wells (EPA 1987; Thyne 2008) linked to fracking in wells. Thyne (2008) had found bromide in wells 100s of feet above the fracked zone. The EPA (1987) documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation. There is also recent evidence of fracking fluid reaching several domestic drinking water wells near Pavillon, WY from a deep source in a sedimentary sandstone and shale formation Diquilio et al 2011). Deep monitoring wells (depth not specified) have detected synthetic organic compounds including glycols, alcohols, and 2-butoxyethanol, BTEX (including benzene at 50 times the MCL), phenols, trimethylbenzenes, and DRO. Dissolved methane was found at near-saturation levels with an isotopic signature similar to production gas. The EPA identified three pathways for fluid movement. One was nearby wellbores. The second was fluid movement from low permeability sandstone into more conductive sandstone nearby. Third was out-of-formation fractures forcing fracking fluid into overlying formations. NYSDEC should consider this example as a cautionary tale of the potential for vertical movement of fracking fluid to near-surface aquifers.

Methane contamination has been observed to occur in many areas near fracking operations. The RDSGEIS acknowledges that gas migration occurs (RDSGEIS, p. 6-42), but suggests it is limited to well construction problems. This assumption ignores the studies which link the source to much deeper formations (Osborn et al 2011, Thyne 2008). Myers (in review) and Osborn et al (2011) indicate that gas transport could indicate pathways which could also be longer-term fluid pathways; if there is a pathway for gas, there is also a pathway for water.

The RDSGEIS dismisses diffusion of chemicals from the shale to the surface because this would dilute their concentrations; this is correct, but diffusion is only a minor process in the movement of chemicals to the surface and is the wrong process to analyze for consideration of

whether vertical transport could occur. Contaminants move by advection, dispersion, and diffusion, with the later being a minor component. Advection would be the most likely transport process (Myers in review). Upward movement of chemicals could occur by advection wherever there is an upward vertical component to the hydraulic gradient; fractures and faults would enhance that flow. Myers (in review) simulated transport through the bulk media as requiring from 100s to 1000s of years, depending on hydraulic properties and gradient; fractures substantially decreased that simulated time.

The RDSGEIS relies on an analysis by ICF (2009), included in the RDSGEIS as Appendix 11, for its dismissal of potential vertical contaminant transport. Dismissing the potential for such transport based on the gradient occurring just for the time of fracking simply illustrates a lack of understanding of the process and associated groundwater and contaminant flow. ICF (2009) had been part of the 2009 version of the DSGEIS. Appendix A of this technical memorandum reviews ICF (2009) again in detail and Appendix B presents a copy of a journal article (Myers in review), which analyzes in detail the potential for transport from the shale to the surface.

The RDSGEIS should reconsider some of its assumptions and implement several regulatory changes, as specified here:

- *ICF (2009) should be removed in its entirety and substituted with an analysis that at least acknowledges the potential risk for long-term contaminant transport from the shale to the surface. All citations to and conclusions based on ICF (2009) should also be removed from the RDSGEIS.*
- *The RDSGEIS should include the foregoing recommendations concerning hydrogeology, and regulations should be promulgated specifically requiring the delineation of properties of the geologic formations above the shale, the locations of fractures, and mapping of the hydraulic gradients near the proposed drillsites.*
- *The RDSGEIS and regulations should require driller to implement a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport, as described below in the section concerning groundwater monitoring.*

Other Pathways for Groundwater Contamination

Section 2.4.5 incorrectly claims that "[i]mproperly constructed water wells can allow for easy transport of contaminants to the well…" (RDSGEIS, p. 2-22). Transport "to the well" depends on flowpaths and gradients near the well which would only marginally be affected by well construction. Improper water well construction does allow transport of contaminants along the casing which could allow contaminants to move among aquifers, once the contaminants reach

the well. Improperly constructed wells can allow contaminants from aquifer layers which were not intended to be screened to transport to the producing layers.

Flowback and produced water are important potential contaminants, primarily in the potential for blowouts or spills just after fracking and in the potential for leaks from the well bore. Estimates are that from 9 to 35% of the injected fracking fluid, expected to vary from 2.4 to 7.8 million gallons per well, would return as flowback (RDSGEIS, p. 5-99). This is a total flowback of 216,000 to 2.7 million gallons per well (Id.). Estimates also indicate that up 60 percent of the flowback would return within the first four days after fracking ceases (RDSGEIS, p. 5-100). The upper estimate based on these ranges is that 60 percent of 2.7 million gallons, or 1.62 million gallons of flowback will occur within four days of the cessation of fracking. Modeling in Myers (in review) confirms both the relative proportion of injected fluid that becomes flowback and the rapid rate.

Flowback is a mixture of returning fracking fluid and formation fluid, but the limited chemistry data presented in the RDSGEIS suffers from being a single sample per well (RDSGEIS, p. 5-105). The RDSGEIS states that some of the data was provided by the Marcellus Shale Coalition, an industry group, but without reference or actually providing the data; it is not possible for the reader to assess or draw independent conclusions that might differ from the statements in the RDSGEIS. The available data does not apparently allow an assessment of the proportion of shale to injected water. For example, samples with very high salt content probably consist more of shale brine than fracking fluid. RDSGEIS Table 5.10 demonstrates, by its illustration of poor water quality, that the water must be contained. The minimum, median, and maximum for TDS, at 1530, 63,800, and 337,000 mg/l, respectively, suggests the proportions vary widely but that more than half of them are saltier than ocean water. The range in chemicals such as benzene, at 15.7, 479.5, and 1950 ug/l, shows that some flowback could be extremely toxic; the NY MCL for benzene is 5 ug/l, thus most of the samples above detect exceed the standard for this contaminant. Because of the toxic chemistry of flowback water, much more data is necessary, as specified here:

- *The RDSGEIS should present temporal flowback data from specific wells, in tabular or graphical form.*
- *The RDSGEIS should present an appendix with raw data provided by the Marcellus Shale Coalition or link to the data on the internet*.
- *Table 5.10 could be made more understandable by including the detect and MCL levels.*

The RDSGEIS promises that flowback would be contained in “water-tight tanks” for onsite handling (Id.), but the document does not discuss the sizing of the tanks. The proposed regulations address flowback and requirements for capturing it at many points (6 NYCRR §560),

but also fails to specify a size. For example, the operator must include “ the number and total capacity of receiving tanks for flowback water” (6 NYCRR § 560.3(a)(12)), and must have secondary containment, “as deemed appropriate by the department”…”sufficient to contain 110 percent of the total capacity of the single largest container or tank within a common containment area” (6 NYCRR § 560.6(x)(26)(i)). Because there are no specifications for the size of the “single largest container”, the required secondary containment sizing is not useful.

- *The RDSGEIS and proposed regulations must specify the necessary total capacity for tanks to contain flowback. The required capacity must reasonably exceed the expected flowback as discussed above. It must be able to capture within four days, 60 percent of the 35 percent of the maximum amount of fluid to be injected for fracking.*

RDSGEIS Chapter 5 lists many chemicals that could be used in fracking fluid, but does not list any properties of these chemicals which could affect their flow through soils or through groundwater. The RDSGEIS does not provide data regarding whether and how much they will be attenuated. However, the RDSGEIS inappropriately relies on attenuation (p. 6-53) to mitigate against the potential for long-distance transport.

- *The RDSGEIS should either provide data concerning the transport properties of the various chemicals or not rely on attenuation as a means of mitigating the transport which could results from spills and leaks.*

Groundwater Quality Monitoring

The previous sections of this report have highlighted the poor water quality of fluids associated with fracking operations – the fracking fluid itself and the produced shale-bed water – and the various pathways for aquifers to be contaminated. Small quantities of either of these fluids can significantly pollute groundwater and surface water. The RDSGEIS provides some setbacks in an attempt to protect various receptors – wells, aquifers, or streams – and the adequacy of these is discussed below. With the potential for spills and leaks from multiple sources associated with these operations, the requirements for groundwater quality monitoring in the RDSGEIS and the regulations is paltry and insufficient, as described here.

The proposed monitoring consists only of testing existing private water wells within 1000 ft of the drill site, or to 2000 ft if none are located within 1000 ft (RDSGEIS, p. 1-10, 7-44). While this is necessary for the protection of the well owner, it is insufficient for the long-term protection of the aquifer. Domestic wells have not been designed to function as water quality monitoring wells which causes many problems in sampling and interpreting the data. Thyne explains clearly why domestic wells are poor monitoring wells:

> First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells are not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply. (Thyne 2008, p 10-11)

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 best way to be certain of intercepting a contaminant passing a point in an aquifer is to span the entire aquifer with well screen. A long screen may increase the chances of detecting the presence of a potential contaminant which may indicate the site being monitored has developed a leak, but will dilute the concentration by mixing contaminated water with cleaner water. A sample extracted from such a well will be a conglomerate of the chemistry of the entire screen thickness; if the screen spans multiple lithologies, the water within the well bore will not be representative of any lithology (Shosky, 1987). It can only be effective only for substances which do NOT naturally exist in the region of the aquifer. Monitoring with long screens is good only for presence/absence determinations.

Concentrations vary throughout an aquifer, both vertically and horizontally. The concentration determined from any well will represent an average over the entire screen length. Therefore, to monitor trends in concentration, screens should span representative vertical sections

The spatial layout of the monitoring well system should be based on the conceptual flow and transport model for flow from the gas well through the aquifer, which includes flow pathways and possible contaminant dispersion. Monitoring wells should be placed as close to the expected flow path as possible, where the concentration will be highest. However, because of uncertainty in the prediction of the flow path, monitoring wells should also be spaced laterally away from the expected flow path. These lateral wells should detect lower concentrations than the one in the predicted flow path. If the lateral wells actually have higher concentration, the predicted flow path may be incorrect and monitoring wells should be added further from the predicted flow path to improve the understanding of the flow and movement of the contaminant plume.

Monitoring wells or piezometers should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that they will intercept the contaminant and to assess the rate of contaminant movement. If many wells detect the contaminant, the concentration variation would indicate the degree of dispersion. Denser well networks will have a better chance of detecting the contaminant and providing accurate description of it dispersal.

Considering the above fundamentals of a monitoring system, the following recommendations, in addition to sampling the existing private wells, should be added to the RDSGEIS and partly replace proposed regulations in 6 NYCCR §560.5(d)

- *The operator should prepare a conceptual flow path model for groundwater and contaminant transport from the drill pad to and through nearby aquifers.*
- *As part of the conceptual model, the operator should estimate the distance that a contaminant would travel from the well pad in various time periods, including one month, six months, one year, and five years.*
- *Dedicated groundwater monitoring wells should be reasonably located along and perpendicular to the projected flow path out to the five-year travel distance. At a minimum, there should be a transect of monitoring wells/piezometers at the one-month travel distance from the well and halfway between the well and important receptors, meaning wells or discharge points such as springs or streams.*
- *Monitor wells should span the surface aquifer and piezometers should have multiport sampling capabilities for twenty foot intervals at the top of the saturated zone and every 100 feet to the bottom of the freshwater zone. This will help establish vertical concentration and hydraulic gradients.*
- *The monitoring system should be established to establish baseline data including seasonal variability for at least one year prior to drilling and fracking.*

Monitoring transport from the deep shale is more difficult because a substantial flux of contaminants could be released from most anywhere in the fractured shale as a result of oil and gas development. Time intervals for transport could be more than 100 years, but fractures could decrease the time frame to as short a time as a few years. Fracture zones therefore could be monitored, but if they are known the industry should avoid fracking near them, both to avoid vertical transport and induced seismicity. It is therefore reasonable to require a dedicated monitoring well in the middle of each well pad wherever there is an upward flow gradient.

- *Industry should establish a multiport piezometer system from the shale to the bottom of the freshwater zone in the center of all well pads.*

- *The industry should provide the funding to maintain the piezometers system for at least 100 years beyond the end of gas production, to account for the long potential travel times.*

WATER RESOURCES

This section concerns primarily the controls on making water withdrawals for fracking. The section focuses on surface water diversions but also considers diversions from aquifers.

The RDSGEIS notes correctly that without proper controls, the withdrawals of water from streams and aquifers to use in fracking could have significant ecologic and hydrologic impacts (RDSGEIS, p. 6-2). The "natural flow paradigm" is a good description of the interdependencies of the stream ecology with all of the hydrologic regimes (RDSGEIS, p. 6-4). The description of the depletion to an aquifer and the interconnection of aquifers with surface water (RDSGEIS, p. 6-5) is also good. Treating the withdrawals as consumptively lost to the system (RDSGEIS, p. 6-9) is appropriate because in essence, with recycling of flowback, the water will not return to the system. These are acknowledgements which should lead to good regulation of withdrawals, if properly considered in the rulemaking.

The discussion and comparison of the withdrawals for fracking with statewide water uses (Withdrawals for High-Volume Hydraulic Fracturing, RDSGEIS, p 6-9 thru 6-13) are scientifically unsupported and irrelevant;. The potential impacts of withdrawals are a matter of scale and depend on their size, the size of the stream, and antecedent moisture conditions.

Much of the regulation of withdrawals from streams focuses on passby flows. The RDSGEIS defines a passby flow as "a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring" (RDSGEIS, p 2-30) which also specifies a low flow condition "during which no water can be withdrawn" (Id.). Specific definitions will be discussed below, but in reality the lower specified values can allow significant damage to occur to streams, especially smaller ones. If the required passby flow is small compared to the average, meaning it has a long return interval, it will only rarely restrict water withdrawals. If flows on the river can be reduced to a low passby flow, then diversions can reduce the flow to low, long return interval rates much more frequently; this is tantamount to imposing low-frequency, high-damaging, drought on the streams much more frequently.

The Delaware River Basin Commission (DRBC) does not have a specific passby flow requirement and usually uses the 7Q10 flow, the seven-day low flow with a ten-year return interval, for water resources evaluation (RDSGEIS, p. 7-13). The RDSGEIS indicates this is not protective (Id.) and as described in the previous paragraph, it would allow the 10-year low flow to manifest

much more frequently. The Susquehanna River Basin Commission (SRBC) regulations are more complicated, but generally use the 7Q10 or from 15 to 25 percent of the average daily flow (RDSGEIS, p 7-15, 16). Neither is protective and the NYSDEC proposes to use the natural flow regime method (NFRM) method for all regions (RDSGEIS, p 7-16).

The RDSGEIS expresses the intent to use the NFRM only in permit conditions, however, as the document acknowledges that guidance has not yet been completed (RDSGEIS, p. 7-3). As authority, the RDSGEIS cites 6 NYCRR § 703.2, which states that "[n]o alteration that will impair the waters for their best usages" will be allowed. "For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit conditions as a protection measure pending completion of guidance." (Id.). NYSDEC also indicates that the requirement could be "imposed via permit condition and/or regulation" (RDSGEIS, p. 7-22).

- *NYSDEC must include the requirement for using the NFRM in the regulations if it is to be consistently enforceable; the proposed regulations do not currently require use of the NFRM to establish the requisite passby flow in a stream.*

The NFRM attempts to protect the distinctive flow patterns for each stream, including the "variable magnitude, duration, timing, and rate of change of flow rates and water levels" (RDSGEIS, p 7-18). The RDSGEIS proposes to use the "Q75 and/or Q60 monthly exceedence values for establishing passby flows" (Id.). An Qx exceedence value is the flow rate which is exceeded x percent of the time. Another way of considering the Q75 and Q60 exceedance values is that the passby flow would be greater than the flow which the stream exceeds 25 or 40 percent of the time. This is much higher than a 7Q10 flow. However, in a small stream, diversions could change a flow regime from wet (higher than average) to significantly below average.

NYSDEC appears to intend that if the watershed exceeds 50 square miles, the passby flow will be Q75 for the winter/spring months of October through June and Q60 for the summer months of July through September, whereas for smaller watersheds (Area<50 sq miles), the Q60 value applies all year (RDSGEIS, p 7-19). NYSDEC at least recognizes that small streams need more protection and that low flows can be more critical during the summer when temperatures are higher. This means that at least 40 percent of the time, withdrawals will not be allowed. For another short time period (up to the time for which the actual streamflow and the required passby flow is less than the preferred withdrawal rate), withdrawals will be limited to prevent the streamflow from being reduced to below the passby flow.

The RDSGEIS does not discuss how the recommended passby flows were chosen, in terms of habitat protected. There is an implication that Q60 and/or Q75 mean the same amount of

habitat would be protected; this may simply be incorrect because streams are not created equal. The NYSDEC should apply a second filter and actually require a determination of the habitat at Q60 and limit the change in habitat. This is one advantage of the Susquehanna River Basin Commission method (RDSGEIS, p 7-15, -16).

The flow estimation method assumes a linear relation between baseflow and drainage area (RDSGEIS, p 7-19). The assumption is that streamflow increases consistently in a downstream direction in proportion to the contributing drainage area. Because it is essential to the method, the RDSGEIS should present data to justify their assumptions. Analyzing streams with two or more gages, the Qx flow at one would be calculated according to the area proportionality relationship with the other gage; the RDSGEIS should present this type of verification to prove the method is suitable.

On streams without gages, the RDSGEIS indicates that NYSDEC will use factors developed from regression equations based on their location in New York (RDSGEIS, Fig 7.1, Table 7.2). The table provides coefficients in cfs/sq mi for the passby flow for the different geographic zone by month. Presumably, they are based on basin areas as discussed above, with different requirements for greater than and less than 50 sq miles. The RDSGEIS should compare values determined with Table 7.2 with the actual value determined for gaged streams to verify the table. Statements such as "[t]he passby flow requirement … would fully mitigate any significant adverse impact from water withdrawals" (RDSGEIS, p 7-22) are unsubstantiated and unjustified.

The passby flow requirements effectively ignore the potential cumulative impacts, irrespective of the following sentence: "The application of the NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time" (RDSGEIS, p. 7-25). The RDSGEIS continues by indicating that "significant adverse cumulative impacts would be addressed by the NFRM … because each operator … would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal" (RDSGEIS, p. 7-25, -26). The RDSGEIS analysis of the prevention of cumulative flow impacts appears limited to these statements. Clearly, several concurrent withdrawals along a stream reach could cumulatively decrease the flow at the more downstream sites to less than the passby flow, if the timing of withdrawals is not controlled and if there are not adequate measurements ongoing at the site which compare the actual flow to the required passby flow. Short of establishing a gaging station with flow/stage relationship, it is difficult to measure flows frequently enough to monitor short-term flow changes, therefore it is unlikely that an operator would be able to react sufficiently to preserve the passby flow.

The following are recommendations for improving the passby flow requirement to be used by NYSDEC

- *The program must be codified into regulations.*
- *The methods for estimating passby flows at ungaged sites must be verified as to their accuracy.*
- *NYSDEC should coordinate operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.*
- *The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.*
- *Passby flows should be maintained with consideration to the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.*

NYSDEC recognizes that groundwater pumping could deplete streams and also recognizes that pumping effects on the aquifers must be limited (RDSGEIS, pp 6-5, -6). Regarding groundwater pumping, the "Department proposes to impose requirements regarding passby flows as stated in this document" (RDSGEIS, p 7-25). The RDSGEIS does not discuss how the potential impacts to a stream will be estimated or how passby flows will be maintained, especially considering the lag time between groundwater pumping and the time for effects to manifest in the streams.

- *NYSDEC should prohibit groundwater pumping in tributary watersheds when analysis indicates that the time for a pumping effect to reach the stream is less than 30 days.*
- *NYSDEC should require a suitable groundwater analysis to estimate the effect on groundwater discharge to streams.*

The RDSGEIS indicates that industry has begun recycling more of its wastewater (RDSGEIS, p. 1-2). Recycling flowback water is good for reducing the amount of water to be disposed of, but it will not significantly decrease the water volume needed for fracking because the amount recovered as flowback is just 10 to 30 percent of the amount originally injected. Tracking the flowback to be recycled should be part of the new "Drilling and Production Waste Tracking" process (RDSGEIS, p. 1-13).

PROJECT MITIGATION MEASURES

The primary mitigation schemes proposed in the RDSGEIS are setbacks, which the RDSGEIS treats as additional precautionary measures (RDSGEIS, p. 1-11). This section considers whether

the setbacks are sufficient or arbitrary. A list in section 1.8 introduces additional precautionary measures; they are repeated in section 3.2.4. The following lists the proposed mitigation setbacks from the RDSGEIS and provides brief comment:

> "Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds."

The primary pathway if wells are prohibited within 4000 feet of the watershed boundary would be underground, since topography would cause contaminants to flow away from the watershed boundary, assuming this coincides with a topographic divide. In general, 4000 feet is probably sufficient, but a site specific consideration of the geology should be included to ascertain that the groundwater divide would not place the well within the watershed and that geologic formations are not dipping in the direction of the watershed.

- *This setback is not specified in the regulations, but should be.*
- *The operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the prohibited watershed.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (6 NYCCR §560.4(a)(2),(subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing)"

The implication of only a 500 –ft setback is that there is no groundwater connection, but if groundwater in the bedrock connects with the aquifer, there is a potential for a rapid transport of contaminants from a spill through fractures to the aquifer. Contamination will easily spread through the highly conductive aquifer (RDSGEIS, p. 6-37). The risk to the aquifer would be the same as to the prohibited watersheds, so there is no reason the distance should be different. If the ground surface slopes from the well to the primary aquifer, there is a significant risk of a spill reaching the aquifer through surface channels.

- *The prohibition in* 6 NYCCR §560.4(a)(2) *should be increased to 4000 feet, unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.*
- *Additionally, the RDSGEIS should publish the area the Marcellus shale zone overlapped by primary aquifers and the area that would be included as buffer; this would help the public to understand how much land the prohibition affects.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (6 NYCCR

§560.4(a)(4)) (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing)"

Essentially, there is no reason for this offset to be less than the offset from a primary aquifer. Considering a public water supply well, the operator should be required to perform a capture zone analysis for the well, and if the well could draw contaminants from a spill to the well, the gas well should not be permitted in that location.

- *The setback for public water supply wells should also be 4000 feet.*
- *Additionally, the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains". (6 NYCCR §560.4(a)(4))

For wells that might operate for 30 years, there is a 26% chance[2] of a 100-year flood occurring during the period the well would be operated.

- *Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, *unless waived by the owner*." (6 NYCCR §560.4(a)(4)), emphasis added.)

NYSDEC should not allow the owner to waive this requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.

- *6 NYCCR §560.4(a)(1) should be changed to remove the waiver from the water well owner unless the owner is required to disclose the waiver to a future buyer in perpetuity.*

In general, some of the points discussed above mention that NYSDEC will revisit the need for the setback in the future. These reconsiderations are not part of the regulations. If so, the NYSDEC should specify in detail the performance standards that must be met in order for the setback requirement to be relaxed, and should acknowledge that a supplemental EIS would be completed to consider those changes.

[2] The probability that a event with a p probability will occur during n observations (years) may be determined with a binomial distribution.

The RDSGEIS also specified the following factors which would require site-specific SEQRA analysis.

1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along any part of the proposed length of the wellbore.
2) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
These requirements should be considered together – if the top of the shale is less than 2000 feet bgs or 1000 feet below the bottom of the aquifer, a site-specific SEQRA review will be required. The depths seem arbitrary, and must be based on a perceived potential for vertical transport from the shale to the receptor.

3) Any proposed well pad within 500 feet of a principal aquifer:
The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond:
Again, rather than allowing development subject toa site-specific study, development within 150 feet of these streams should be prohibited. It is difficult to imagine how study will prevent a spill which is, by its nature, unexpected.

5) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7;
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6) Any proposed water withdrawal from a pond or lake;
7) Any proposed ground water withdrawal within 500 feet of a private well;
8) Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland:
Requirements 5 through 8 are acceptable limits for requiring site-specific study.

9) Any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure

This applies to areas outside the NYC watershed that contain NYC infrastructure (RDSGEIS, p 6-1). It is unclear whether there is any infrastructure that would actually be affected by fracking outside of the watershed. Fracking should not be allowed within 1000 feet of any NYC water supply infrastructure to prevent damage.

Acid Rock Drainage

The RDSGEIS refers in several locations to an acid rock drainage (ARD) mitigation plan which would be required for the on-site burial of Marcellus Shale cuttings (RDSGEIS, p 7-67). In general, our recommendation is that on-site burial not be allowed (see the report by Harvey Consulting, LLC). NYSDEC does not describe an adequate mitigation plan to prevent the leaching of ARD into groundwater. It does not specify testing which is essential to know how much neutralizing rock must be supplied.

For each well, prior to disposal of the cuttings, an adequate set of samples should be collected from the cuttings to test for acid generation. Adequate sampling would be representatively spaced along the horizontal well bore; initially, many samples would be needed to determine the variability among samples; samples every 100 feet would be desirable until sufficient data is collected from New York shales to characterize the variability along the horizontal well bore.

At least three types of testing should be completed:

- Acid base accounting – Modified Sobek procedure
- Net acid/alkaline production
- Meteoric water mobility testing – ASTM E-2242-02

These tests should provide adequate information to determine the amount of neutralizing rock which should be added to the cuttings to prevent ARD from leaching through the waste. Ideally, if the rock is potentially acid generating (PAG), kinetic tests should be completed to better assess the PAG potential, but this may not be possible in a timely fashion. The regulations should reflect these testing requirements. Final disposal must include adequate encapsulation to assure neutralization in perpetuity. It must also include adequate monitoring to assure that ARD does not leach into the underlying groundwater. A mitigation plan must be in place to remediate any disposal sites that do leak ARD.

COMMENTS ON SPECIFIC PROPOSED REGULATIONS

The proposed regulations increase the overlap lengths for cement plugs in abandoned O&G wells from 15 to 50 feet at several locations (6 NYCRR§ 555.5(a)). This increase in plug length is an improvement but not sufficient or well planned in all locations. Rather than filling “with

cement from total depth to at least 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity" (6 NYCRR§ 555.5(a)(1)), the regulation requiring cementing to 50 feet above the top of the shallowest formation in which gas has been observed; not all gas pockets have actually produced gas but could cause methane contamination if they are not already sealed off by casing. The regulations should specify that the cement plug "below the deepest potable fresh water level" should overlap the transition than be just below it because even a short section of uncased well bore open to the salt water could mix into the well and to above the fresh water line (6 NYCRR§ 555.5(a)(3)).

The definition of "public water supply" (6NYCRR§ 560.2(19)) appears to include only groundwater by referring to "a…well system which provides piped water". However, the definition of "reservoir" (6NYCRR§ 560.2(20)) includes "waterbody designated for use as a dedicated public water supply". The regulations must clear up this inconsistency by making clear that a "public water supply" includes ground- and surface water.

Operators must include in their applications various items (6NYCRR§ 560.3). The following address some of these requirements by number (the setback requirements were addressed above in the section concerning setbacks).

(2): The estimated maximum depth and elevation of bottom of potential freshwater: The operator should also be required to complete geophysical logging including conductivity measurements to verify the depth, unless it had been based on "previous drilling on the well pad".

(3): The "proposed volume of water to be used in hydraulic fracturing": The operator should also be required to discuss and specify how the estimated volume was determined.

(5), (6): The two parts specify that the application will provide the distance to various features but only if they are within a given specific distance. With current geographic information systems technology, there is no difficulty in obtaining these distances. The application should provide the distance to the water supply features in (5) and the aquifer and stream features in (6) if they are within two miles.

Mapping requirements for the application are specified in 6 NYCCR § 560.3(b). The topographic map requirements (6 NYCCR § 560.3(b)(2) require essentially a site map within 2640 feet of the proposed surface location (RDSGEIS, p. 3-9). This should be increased to 1 mile from the site, so that the map would be two by two miles centered on the proposed well pad. The map should include locations of all aquifers, water wells, stream channels, and other water features. The map should also include surface geology including faults. If fractures dominate the surface bedrock, contaminants can move quickly to wells. Contaminant pathways for transport from

the pad should be identified on the map. Contaminants would not move far upgradient, so the NYSDEC should focus downgradient. The following recommendations should be included in regulations regarding the requirements of well drillers to take steps to protect nearby wells.

- *The operator should complete site specific geology/hydrogeology studies to map the potential flow paths for contaminants released from the well pad or the well bore.*
- *All wells within a five-year transport zone should be located and included in sampling plans discussed below. Additionally, dedicated monitoring wells should be established within this zone, also as described below.*

The regulations require the operator to record and report the depths and flow rates where “freshwater, brine, oil and/or gas were encountered or circulation was lost during drilling operations” (6 NYCCR 560.6(c)(22)). The operator should identify these areas with specific conductivity logging. The regulations do not specify any limits or actions that the operator should take if certain flow or losses were recorded; they do not specify what the department will do with this information.

The required treatment plan “must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage” (6 NYCCR 560.6(c)(22)). The operator also “must make and maintain a complete record of it hydraulic fracturing operation including the flowback phase” (6 NYCCR 560.6(c)(26)viii). The operator should compare the “anticipated pressures and volumes” with the actual values.

The operator must suspend operations immediately “if any anomalous pressure and/or flow conditions is indicated or occurring which is a significant deviation from either the treatment plan” (6 NYCCR 560.6(c)(26)vii). This is good, but the regulations do not define anomalous or what a significant deviation from the treatment plan would be, or what the follow-up action would be to assess and remedy damages.

Also, the required record of the fracking operation, 6 NYCCR 560.6(c)(26)viii, includes rates, volumes, and pressures of all injected and flowback fluids to the well. The department only requires a synopsis be provided to the department. There is no description what a synopsis should include. Instead, the department should require the full record be provided to the department, and this record should be made publically available online.

The regulations allow a well owner to waive setback requirements (6NYCRR§ 560.4(a)(1)). This should not be allowed unless there is also a requirement to inform potential purchasers of the well in the future of the waiver.

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APPENDIX A

Review of Appendix 11, Excerpt from ICF Report, Task 1, 2009

Analysis of Subsurface Mobility of Fracturing Fluids

Agreement No. 9679

Reviewed by

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December 7, 2009

Revised: November 14, 2011

Introduction

The New York State Energy and Development Authority (NYSERDA) contracted with ICF International to prepare a review of the hydraulic fracturing process as it will likely be applied to the Marcellus Shale in New York; this review was published as a supporting document for the 2009 RDSGEIS prepared by the New York State Department of Environmental Conservation. For the 2011 RDSGEIS, Appendix 11 presents excerpts from that report regarding the subsurface mobility of fracturing fluids. This is a review of Appendix 11, revised from a review completed by this author of the ICF International report contained in the 2009 RDSGEIS.

In summary, ICF completed an analysis of the potential for contamination to flow from the shale to freshwater aquifers, but misrepresented the actual situation in many ways. The basic problem was they conceptualized the flow potential incorrectly. They considered the gradient incorrectly and assumed that if the transport did not occur within the time period of fracturing, it would not occur. They assumed that the fluids leaving the shale would completely disperse, and be diluted, by occupying and being retained in every pore between the shale and the aquifers. They did not consider preexisting fractures. They ignored any potential pre-existing vertical gradient which would drive contaminants leaving the shale to the aquifers. Although they presented a geochemical analysis which could explain why some attenuation could occur, they provided no site specific or fluid specific data to indicate that it would occur.

Exposure Pathways

ICF analyzes the potential for fracturing fluid to flow from the shale to the freshwater aquifers anywhere from 1000 to 5000 feet above. The first problem is that the potential contaminants are both fracturing fluid and connate (formation) water existing in the shale before fracturing, which could contain extremely high concentrations of TDS, benzene, or radioactive materials. Therefore, ICF should have considered the potential for flow of both fracturing fluid and connate water. Ambient water could both be pushed from the shale by the injection of fracturing fluid and just by the opening of the pore spaces which would increase the permeability and allow more of a natural connection.

ICF calculates the gradient between the fracture zone and the bottom of the freshwater zone, which they set at 1000 feet bgs to be conservative in because much of the groundwater below this level in southern New York is not an underground source of drinking water either because it is too salty or the formation is not sufficiently productive to be considered an aquifer. However, their calculation applied only during the period of injection. Myers (in review) demonstrated through modeling that the fracking pressure would dissipate over a period of months, not immediately after fracking ended, because of the fluid that has been pushed away from the well. The effective gradient is from the well to just beyond the migrating fluid where pressures would not yet have been affected by the current fracking.

ICF also ignores the potential for a natural upward gradient, which could be due to natural artesian pressure. Myers (in review) also discusses the potential for this in detail.

ICF properly calculated the pressure that would occur in the shale during fracturing based on the effective stress in the formation and the amount of pressure required to overcome the in-situ horizontal stress (ICF, pages 25-26); accepting the assumptions in the following quote, equation 12, and equations 7 through 11 used to derive it, is an accurate description of the head applied to the shale during fracturing.

> Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth. To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress… (ICF, pages 25-26)

ICF uses that equation with the gradient equation 6 to estimate the gradient between the shale and freshwater aquifer, “during hydraulic fracturing”, for a variety of depths of the aquifer and the shale. The numbers are correct, for an aquifer depth of 1000 feet and shale depth of 2000 feet, they show the gradient to be about 3.6, but the concept applied in the derivation is wrong as described above. During hydraulic fracturing, variously estimated through the RDSGEIS

documents as occurring for up to 5 days, there is no hydraulic connection between the shale and the bottom of the freshwater aquifer and it is therefore inappropriate to consider the gradient across that thickness. The correct conceptualization is described in the following paragraph.

Upon applying a pressure in the shale, as occurs during the injection for fracturing, a very high pressure head is developed at the well and nearby shale. This pressure causes the gradient that drives the fluid away from the well into the shale, where it causes the shale to fracture. Fluid may continue to flow into surrounding formations. During the process, the pressure begins to increase away from the well which establishes a steep gradient near the well. Away from the well at any given time during injection, the pressure is less than at the well. The pressure drop from the well to any point in the shale away from the well is a function of the friction incurred by the fluid flowing away from the well. At some distance from the well, the pressure is only at background. The distance at which the pressure is only background is the point at which the injection fluid has not yet reached. Beyond the point to which the injection fluid flows, there is NO hydraulic connection. For this reason, ICF's calculation for gradient between the injection pressure in the shale and the bottom of the freshwater aquifer is hydrogeologically incorrect. ICF is effectively analyzing a steady state situation that would occur if the injection pressure continued until the pressure stabilized between the shale and the freshwater aquifer.

ICF acknowledges the reality that transient or non-steady conditions will prevail and that the actual pressure gradient will be higher closer to the shale. "In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer to the fracture zone and lower than the average closer to the aquifer." (ICF, pages 26-27)

However, they do not carry the analysis any further and seem to argue that immediately after injection ceases, all upward gradient will cease: "It is important to note that these gradients only apply while fracturing pressures are being applied. Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer" (ICF, page 27). The implication from this statement is that ending injection will cause the pressure in the reservoir to drop back to background, immediately. This is not possible, any more than it is possible for the drawdown in a pumping well in an aquifer to return to pre-pumping conditions immediately upon cessation of pumping.

For example, consider that during a five-day injection period, the pressure propagated outward from the well as described in Myers (in review). When injection ends, the pressure within the well may almost immediately return to background, but the pressure in the surrounding formation will still be very high. This is the pressure which will drive the flowback to the well, as described throughout the RDSGEIS. The initial flowback is fluid right next to the well – the

fluid that had just been injected. The pressure field created in the formation away from the well is the pressure that causes a gradient to push the fluid back into the well.

As long as there is flowback, there is a gradient toward the well, and residual pressure in the shale or surrounding formations. With distance from the well, the pressure increases (as required for there to be a gradient back to the well). At any given time, there will be a point of maximum pressure beyond which the pressure becomes lower; in other words, a cross-section through the formation away from the well showing the pressure head would show the pressure rising from the well to the peak and falling from the peak to the point the pressure reaches background. (This is similar to the concept in hydrogeology that during pumping, the maximum drawdown caused by a well is at the well; when the well ceases to pump, the water level will initially rise quickly, but the drawdown away from the well will continue to expand for a period of time.)

ICF considers that local drawdown caused by production from the well will further prevent flow away from the well: "During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow" (ICF, page 27). This is probably correct, but the process described in the preceding paragraph likely causes some of the fluid to have moved beyond this propagating drawdown. The fact that only 35% of the injected fluid returns as flowback (RDSGEIS, Gaudlip et al, 2008) would seem to confirm that much of the injected fluid gets beyond the point where the reversing gradient would pull the fluid back to the well.

ICF also relies on there being no connection between the shale and surrounding formations, as indicated by the high TDS content of water in the shale. This may reflect the pre-fractured conditions, but the fracturing process could open a connection between formations. As noted in the main body of this review, out-of-zone fracking is not uncommon, therefore it is reasonable to assume that connections between the shale and surrounding formations do occasionally occur.

The analysis provided by ICF in section 1.2.4.3, Seepage Velocity, is irrelevant because it considers the velocity between the shale and the freshwater aquifer, using a gradient established in the previous section that only applies for as long as the injection. Their calculation of 10 ft/day (ICF, page 28) relies on that average gradient. They seem to acknowledge the fallacy of their assumptions by stating: "The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata" (ICF, page 28, emphasis added). ICF carries the error into section 1.2.4.4, Required Travel Time, by calculating how long it would take for flow at the seepage velocity calculated in the previous section to reach the freshwater aquifers.

ICF's fourth argument is that even if all of the injected fluid moves vertically out of the shale towards the freshwater aquifer, it would have to disperse among all of the pores between the shale and the aquifer – a truly nonsensical idea. The calculation requires that 4,000,000 gallons of fluid would be evenly dispersed throughout a 40-acre well spacing. In other words, they assume that about 4,000,000 gallons of injected fluid would evenly disperse through all of the void, assuming porosity of 0.1, over a 1000-foot thickness 40 acres in area, or about 1.3 billion gallons of void space, would cause a dilution factor of 300 (ICF, pages 30-31). This is wrong for the following reasons.

- An injected fluid would move as a slug along the gradient. In this case, with a natural upward gradient, any fluid that escapes the well bore (does not flowback) would disperse upward. It would not diffuse through every pore space between the shale and aquifer. Advective forces would move it upward as a slug with dispersion spreading it out both vertically and horizontally. It will dilute, but far less than postulated by ICF's analysis.
- The vertical flow would follow preferential flow paths rather than advecting upwards uniformly across 40 acres. The image painted by ICF is that the fluid would flow upward to the aquifer with the leading edge moving at exactly the same rate over the entire area. Even if there are no fractures, faults, or improperly plugged wells, simple finger flow, caused by heterogeneities in the material properties, would cause an uneven distribution of the contaminant.

ICF also rejects the concept of fractures, faults, or unplugged wells by claiming it is "extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer" (ICF, page 31). They provide no data or references to assess the probability that such a network is "extremely unlikely" or to justify their conclusion. More importantly, for fractures to facilitate a connection between the shale and the aquifers, it is not necessary for the fracture to exist over the entire thickness. As ICF (page 5) mentions, the Marcellus Shale has substantial natural fractures, and therefore it is possible that the surrounding formations, sandstone or shale, also have fractures. It is not necessary for the flow to follow a fracture all the way to the aquifers, but it could enhance the velocity of movement. Fractures could also further disperse the flow vertically, as discussed in Myers (in review).

ICF also mentions geochemistry as a reason that transport of contaminants from the shale to the aquifers will not occur. While it is possible for attenuation to occur as contaminants move through a formation, without site specific and chemical specific data, they should not make such an argument.

Reference

Gaudlip, A.W., L.O. Paugh, and T.D. Hayes, 2008. Marcellus shale water management challenges in Pennsylvania. Society of Petroleum Engineers Paper No. 119898.

APPENDIX B

Prepublication Copy

Myers, T., in review. POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

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ABSTRACT

Hydraulic fracturing (fracking) of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways – diffuse transport through bulk media and preferential flow through fractures – could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative numerical modeling shows that diffuse transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 liters of fluid into the shale generates high pressure at the well which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media and widens existing fractures. Simulated pressure returns to pre-injection levels in about 90 days. The overall system requires from three to six years to reach a new equilibrium reflecting the significant changes caused by fracking the shale. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53 percent of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1).Unconventional shale-bed NG differs from conventional sources in that the permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation (Kramer 2011)) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects 13 to 19 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2010), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale. Horizontal wells may be more than a kilometer (km) long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9 to 34 percent of the injected fluid (Alleman 2011; NYSDEC 2009), although some would be formation water.

Many agency violation reports and legal citations (ODNR 2008; PADEP 2009) and peer-reviewed articles (DiGuilio et al. 2011; Osborn et al. 2011; Breen et al. 2007; White and Mathes 2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources – thermogenic for gas formed by compression and heat at depth in shale and bacteriogenic for gas formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al 2007). Thermogenic

gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found there to be more gas near fracture zones (DiGuilio et al. 2011; Osborn et al. 2011; Thyne 2008; Breen et al. 2007), suggesting that fractures are pathways for gas to move from shale or other deep formations to aquifers.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the time for transport would likely be longer. Two reports (DiGuilio et al. 2011; EPA, 1987) have documented the presence of fracking fluid in aquifers and another found elevated chloride (Thyne 2008), linked to fracking, in wells, although the exact source and pathways had not been determined.

There is sufficient documented gas movement and circumstantial evidence regarding fluids movement to suggest that there is a potential for fracking fluid or shale-bed formation fluid to reach aquifers. With the vastly increasing development of unconventional NG sources, the risk to aquifers could seemingly be increasing. However, there is almost no data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers. The only way in the short term to explore the risk is with conceptual analyses.

To consider the potential transport from depth to aquifers, I have considered first the potential pathways for contaminant transport through bedrock between deep shale and surface aquifers, and the necessary conditions for such transport to occur. Second, I have estimated contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel

times compared to those considered herein. The intent of this study is to characterize the risk factors, so the modeling is used, similar to that by Hsieh (2011), to consider the possibilities.

The Marcellus shale area of northern Pennsylvania and southern New York is the study area (Figure 1), although the concepts should apply anywhere there is a deep unconventional NG source separated from the surface by sedimentary rock.

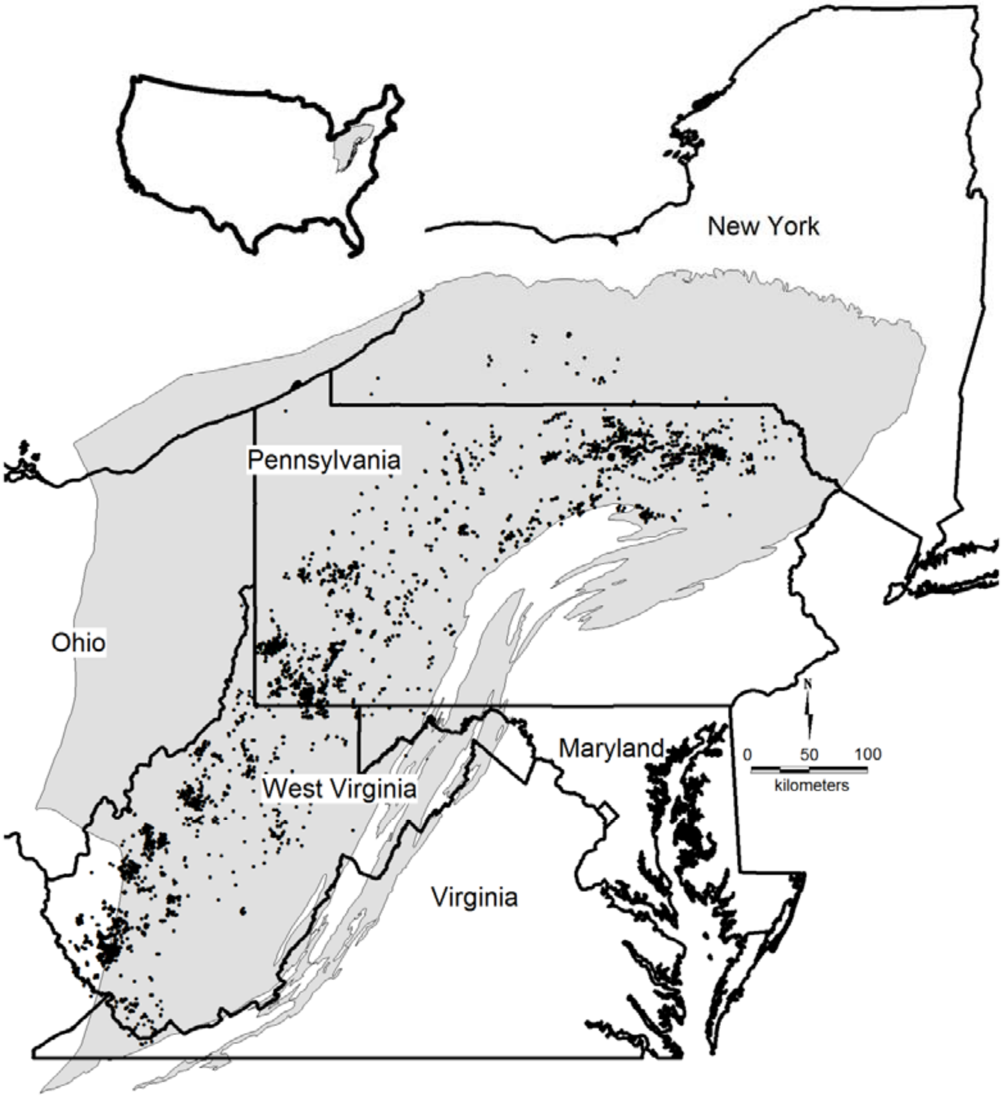

Figure 2: Location of Marcellus shale in northeastern United States. Location of Marcellus wells (dots) drilled July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area may be found in PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a and 2010b).

Method of Analysis

I consider several potential scenarios of transport from shale, 1500 m below ground surface to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach the overlying formations. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles, which tend to break in one direction (Nichols 2009). It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. Because sufficient organic matter settled with the clay and silt, anaerobic decomposition caused the formation of methane. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York. Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYSDEC 2011).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a and 2004b; Neuzil 1994 and 1986), which makes it an extremely efficient seal, or capstone, for keeping natural gas in underlying sandstone. At a gradient equal to 1 with an intrinsic permeability equal to $100x10^{-9}$ darcies, water would flow only 0.000025 m in a year.

Schulze-Makuch et al. (1999) described Devonian Shale of the Appalachian Basin, of which the Marcellus is a major part, as containing “coaly organic material and appear either gray or black” and being “composed mainly of tiny quartz grains < 0.005 mm diameter with sheets of thin clay flakes”. Median

particle size is 0.0069±0.00141 mm with a grain size distribution of <2% sand, 73% silt, and 25% clay. Primary pores are typically 5 x 10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 0.078 to 0.09% (Schulze-Makuch et al. 1999 and references therein).

The Marcellus shale is fractured by faulting and contains synclines and anticlines which cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just six to ten km from where it is being developed for NG at 2000 m below ground surface (bgs) in eastern Lycoming County, Pennsylvania (Lloyd and Carswell 1981) (Figure 2).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales the fractures control and may allow significant flow. Conductivity scale dependency (Schulze-Makuch et al.1999) may be described as follows:

$$K = Cv^m$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), V is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals -14.3 and m equals 1.08 (Schulze-Makuch et al. 1999). Most of their samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have calibrated for flow through the Marcellus shale, therefore field scale K estimates are uncertain. Considering a 1 km square area with 30 m thickness, the Kh would equal 5.96×10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Three studies (Osborn et al. 2011; Thyne 2008; Breen et al. 2007) have found gas in near-surface water wells and suggested that the most likely cause was vertical transport of gas from depth, possibly linked to the presence of faults through which the gas could flow. Osborn et al. (2011) found systematic

circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells that had been fracked. Gas moves through fractures depending their width (Etiope and Martinelli 2001) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and natural gas storage projects (Breen et al. 2007).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement of contaminants from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/l (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread diffuse transport, which would occur if there is a sufficient concentration gradient. The transition from briny to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater.

Faults, which occur throughout the Marcellus shale region (Gold 1999), could provide pathways (Caine et al. 1996; Konikow 2011) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

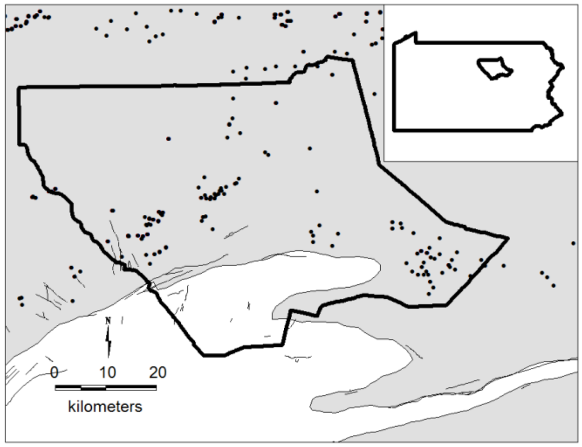

Figure 3: Marcellus shale wells and the Marcellus outcrop in Lycoming County, Pennsylvania. The grey shading is the area of Marcellus shale, which outcrops along its boundary along an area about 1 km wide (Lloyd and Carswell 1981). Faults from PBTGS (2001).

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of natural gas economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties such as conductivity were found while researching this article (there is a lack of information about pre- and post-fracking properties (Schweitzer and Bilgesu 2009)), but it is reasonable to assume the K increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Krissane and Weissert 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Krissane and Weissert 2011) which indicates that 300–m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow

would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out of formation fracking is not uncommon. Fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale. For example, if 15 million liters is injected into shale over a 1000 m long horizontal well, the fluid could occupy all of the pore spaces within 7 to 16 m from the well for effective porosity ranging from 0.1 to 0.02. Even with 20% of the fluid returning to the well, a significant amount of existing pore space would be occupied by the injected fluid, displacing the existing brine and gas.

Analysis of Potential Transport along Pathways

Fracking could cause contaminant to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport will manifest if there is a significant vertical component to the regional hydraulic gradient. Advective transport can be considered with the simple particle velocity determined with Darcy velocity and effective porosity.

Numerical modeling provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman, 2007). Numerical simulation presented herein was completed with the MODFLOW-2000 code (Harbaugh et al. 2000). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but it is not perfect for all of the factors required for this simulation. The native water at depth near the shale is brine, much saltier than seawater, therefore the injected fluid would be lighter so buoyancy factors may speed the upward flux beyond the simple consideration of hydraulic gradient. As more data becomes available, it may be useful to consider the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This paper considers the fractures as vertical columns with cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling would not be useful because high velocity vertical flow through the fractures is unlikely. MODFLOW-2000 has a module, MNW (Halford and Hansen 2002), that could simulate flow through open bore holes. Open boreholes would clearly provide rapid transport if the head deep in the borehole exceeds that near the surface or if fractures containing fracking fluid intersect or come close to the borehole. Because it is possible to simply plug open boreholes, I have limited consideration here to fractures; however, models of well fields should include known boreholes.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, sections of shale, mudstone, and limestone could exert local control. The vertical fault is assumed to be 6 m thick.

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider with an interpretative numerical model.

1. The natural upward diffuse flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden and is a baseline condition for upward flow through unfractured sedimentary rock.
2. Same as number 1, but with a fracture zone connecting level of the shale with the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K.
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K in the shale layers increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. This scenario estimates both the changes in flux and the time for the system to come to equilibrium after fracking.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in five days into fractured shale from a horizontal well with and without a fault.

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450 m square (Figure 3) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m layer 29, 9 m to layer 26, 18 m in layer 25, 30 m to layer 17, 60 m to layer 6, 90 m to layer 3, and 100 m in layers 2 and 1

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create an upward gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

This simulation considers particle travel times between the top of the shale and the top of the model domain based on an effective porosity of 0.1. A 6-m wide fault is added for some scenarios in the center two rows from just above the shale, layer 39 to the surface. The fault is an attempt at considering fracture flow, but the simulation treats the six meter wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow, 2011).

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 3). It injects 15 million liters over one 5-day stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled shale K was changed to its assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh, 2011) and water quality changes caused by underground coal gasification (Contractor and El-

Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for sixty days after the completion of (Figure 3), after which the DRAIN was deactivated. The sixty days were broken into four stress periods, 1, 3, 6, and 50 days long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 days to emulate standard industry practice (Alleman 2008; NYSDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 days, a length of time that simulation of scenarios 3 and 4 indicated would suffice.

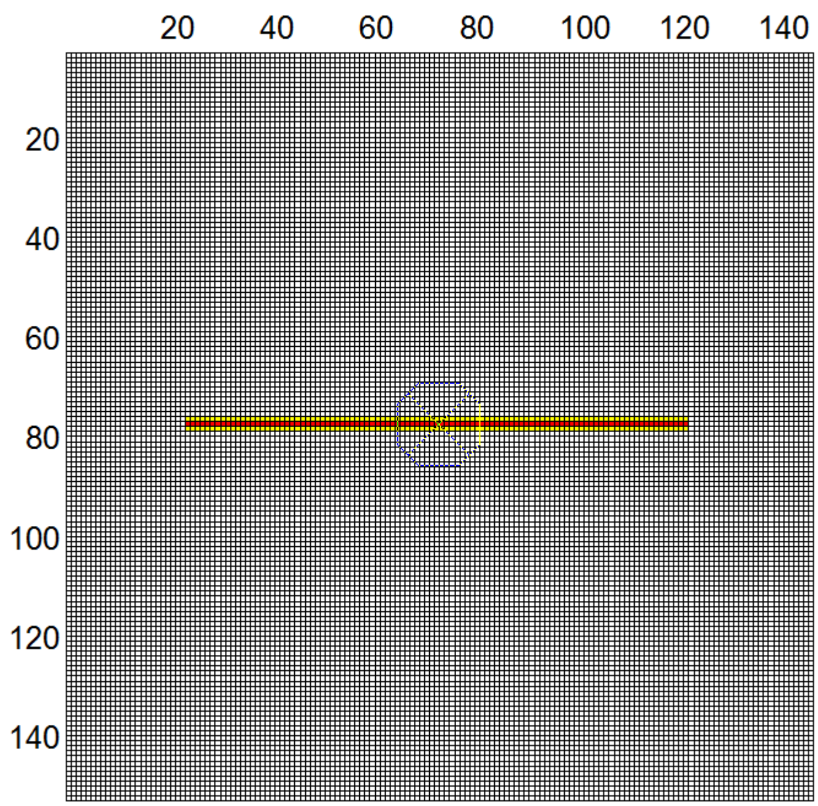

Figure 4: Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. The figure also shows the monitoring well.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured shale K equal to 0.001m/d, two orders of magnitude higher than the in-situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7} m^{-1}, varied twofold (Figure 4). The slowest time to equilibrium was for $S=10^{-3}$ m^{-1} (Figure 4), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

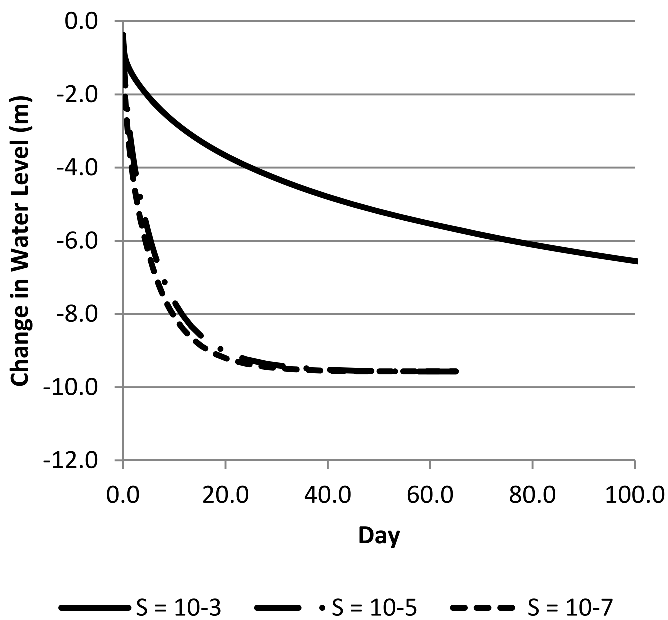

Figure 5: Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

Results

Scenario 1

The travel time for a particle to transport through 1500 m of sandstone and shale equilibrates with one of the formations controlling advection (Figure 5). For example, when the shale K equals $1x10^{-5}$ m/d, transport time does not vary with sandstone K. For sandstone K at 0.1 m/d, transport time for varying

shale K ranges from 40,000 years to 160 years. The lower travel time estimate is for shale K similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 5). If shale K is low, travel time is very long and not sensitive to sandstone K.

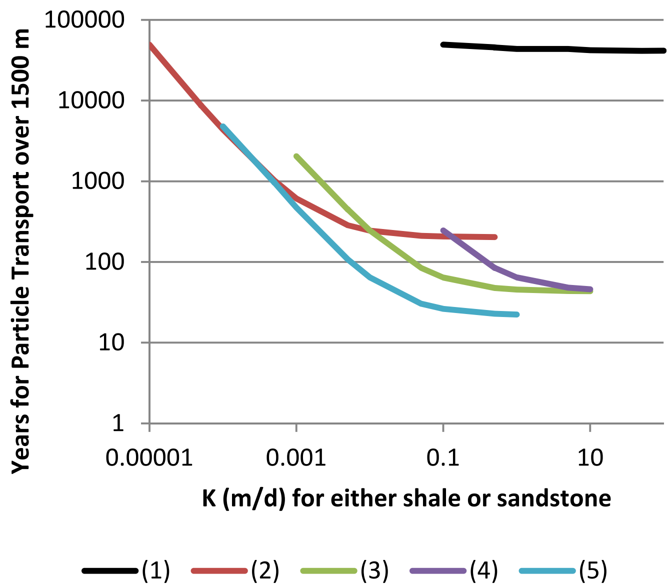

Figure 6: Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1) – varying Kss, Ksh=10-5 m/d, (2) – varying Ksh, Kss= 0.1 m/d, (3) – varying Kss, Ksh = 0.1 m/d, (4): varying Kss, Ksh = 0.01 m/d, and (5): varying Ksh, Kss= 1.0 m/d.

Scenario 2

Vertical transport time through a system including a high-K fault zone was limited primarily by the shale K, presumably because the fault K was one to two orders of magnitude more conductive than that of the surrounding sandstone (Figure 6). Including a fault increased the particle travel rate by about 10 times (compare Figure 8 with Figure 6). The fault K controlled the transport rate for shale K less than 0.01 m/d. A highly conductive fault could transport fluids to the surface in as little as a year for shale K equal to 0.01 m/d (Figure 6).

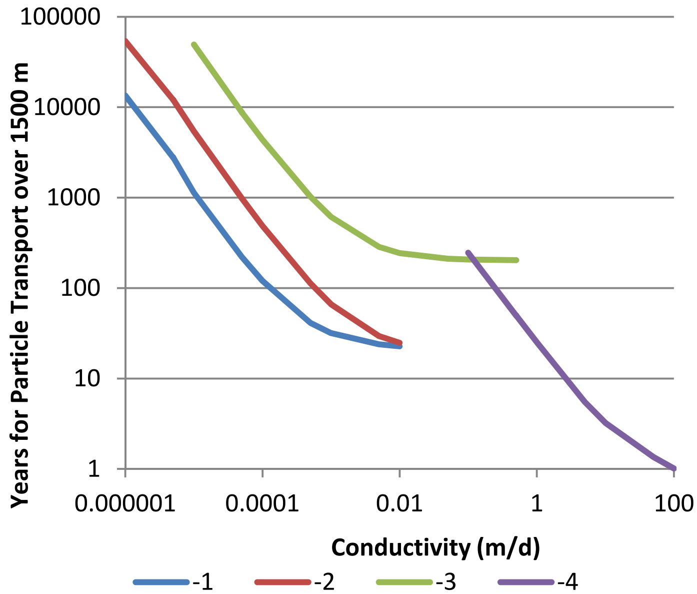

Figure 7: Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1): Vary Ksh, Kss=0.01 m/d; (2): Varying Ksh, Kss=0.1 m/d; (3), no fault; (4): Varying K fault, Kss=0.1 m/d, Ksh=0.01 m/d. Unless specified, the vertical fault has K=1 m/d for variable shale K.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium for scenarios 1 and 2. Equilibrium times would vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the ultimate adjustment of the potentiometric surface to steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, shale K changing from 10^{-5} to 10^{-2} m/d with sandstone K equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 7). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher in layer 20, the head increased about 20 m. These changes reflect the decrease in K across the shale. Simulation of scenario 4, with a fault with K=1 m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone,

depending on model layer (Figure 7). Faster transport occurred only in areas near the fault. Highly fractured sandstone would allow more vertical transport, but diffused advective flow would also increase so that the base sandstone K would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 m/d to 0.0017 m/d. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

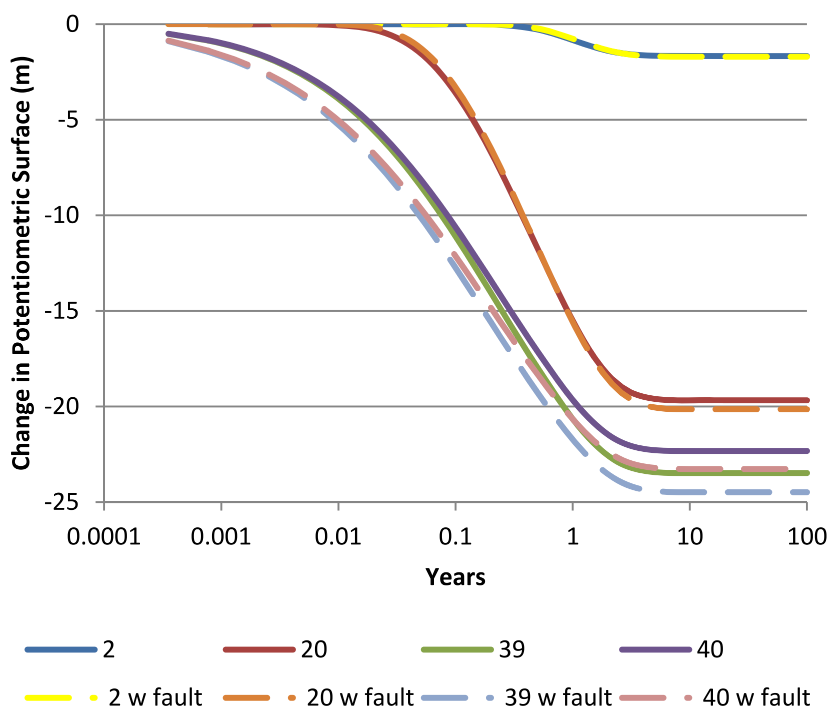

Figure 8: Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface

increases (highest injection pressure) occurred at the end of injection (Figure 8), with a 2400 m mound at the horizontal well. The peak pressure simulated both decreased but occurred longer after the cessation of injection with distance from the well (Figure 8). The pressure at the well returned to within a meter of pre-injection levels in about 95 days (Figure 8). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 9), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 9), as simulated in scenario three. The scenario required about 6000 days (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 9). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

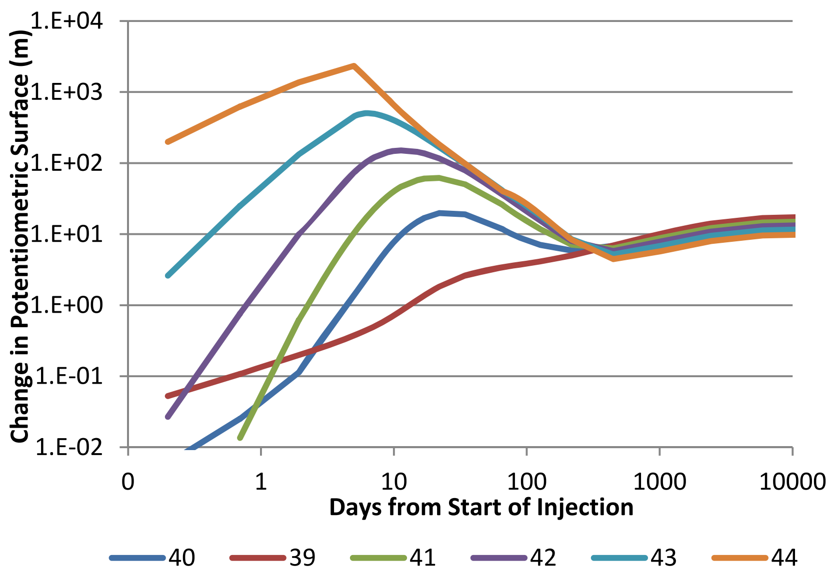

Figure 9: Simulated potentiometric surface changes by layer for specified injection and media properties; Kss=0.01 m/d, Ksh = 0.001 m/d, Kfault = 1 m/d. S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

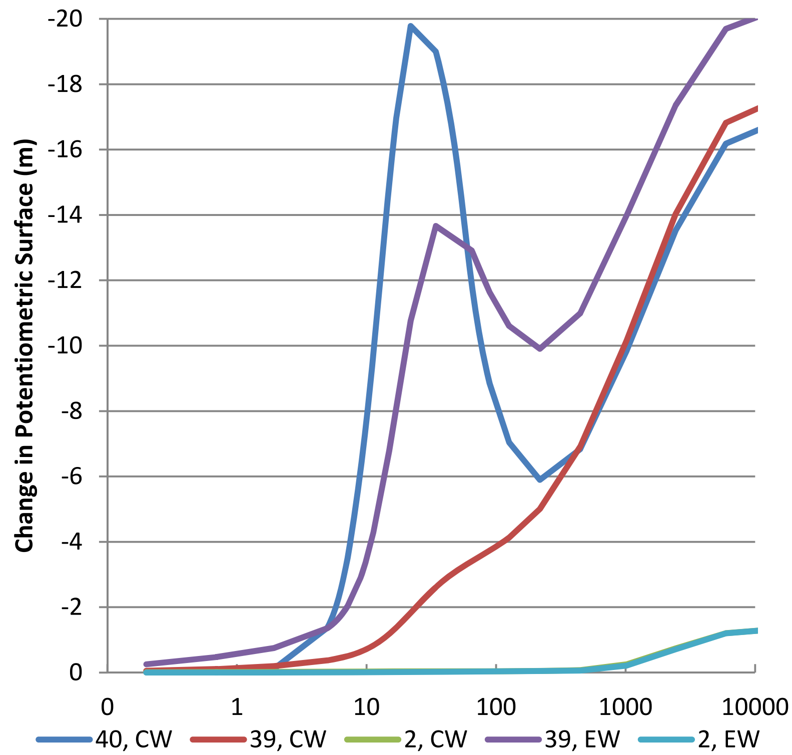

Figure 10: Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for Layer 2, CW plots beneath the line for Layer 2, EW. Kss = 0.01 m/d, Kshale = 0.001 m/d, Kfault=1m/d, S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

Prior to injection, the steady flow for in-situ shale ($K=10^{-5}$ m/d) was generally less than 2 m^3/d and varied little with sandstone K (Figure 5). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as sandstone K ranges from 0.01 to 0.1 m/d (Figure 10), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 8). Adding a fault to the scenario with sandstone K equal to 0.01 m/d increased the flux to about 63 m^3/d with 36 m^3/d through the fault (Figure 10) and decreased the particle travel time to 31 from 2390 years. The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

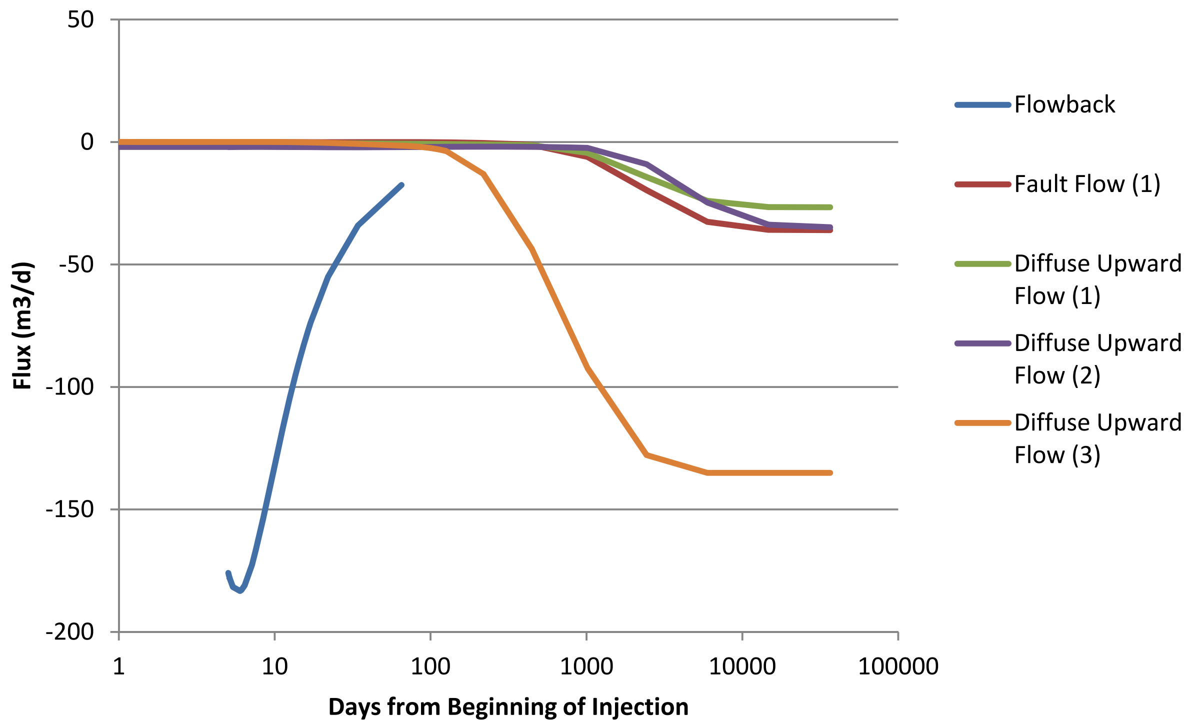

Figure 11: Various fluxes for three separate scenarios. Flowback is the same for all scenarios. (1): Kss=0.01 m/d, Kshale = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Kshale = 0.001 m/d, no fault; (3) Kss= 0.1 m/d, Kshale = 0.001 m/d, no fault.

Simulated flowback varied little with shale K because it had been calibrated to be 20 percent of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback. Lower K would also lead to higher injection pressure which in turn would fracture the shale more.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 11). After 600 days, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year steady flux is about 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

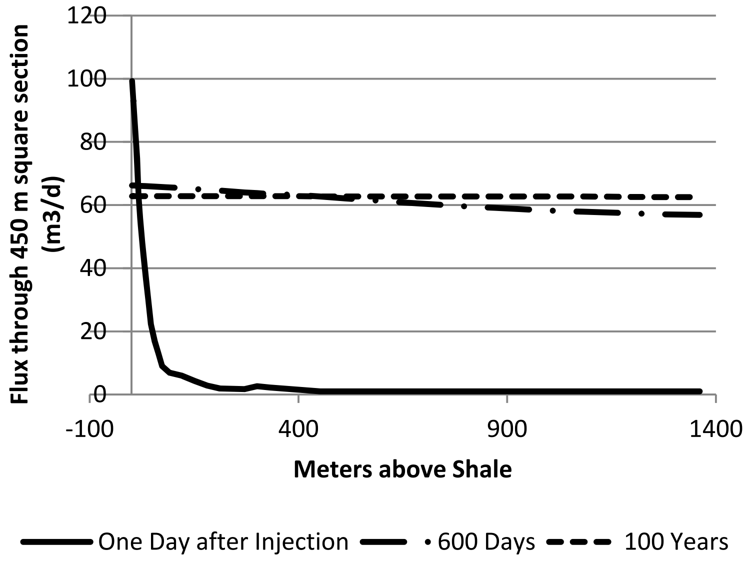

Figure 12: Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for five days causes extremely high pressure within the shale that decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 90 days, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within six years due to changes in the shale properties. The same order of magnitude would apply to changes in shale properties from less to more conductive. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring hundreds of years or less within less than ten years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher sandstone K 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in-situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 5). If the shale K is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the shale K by several orders of magnitude. The regional hydrogeology changes due to the increased K. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYSDEC 2011) actually occurs.

Sixth, fault fracture zones coming close to contacting the newly-fractured shale could allow contaminants to reach surface areas in tens of years. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time

scales to as few as tens of years. Preferential flow through fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

Acknowledgements

This research was funded by the Park Foundation and Catskill Mountainkeepers. The author thanks Anthony Ingraffea, Paul Rubin, and Evan Hansen for helpful comments on the paper.

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Appendix C

Review of NYSERDA Commissioned Review of Myers Comments on the 2009 DSGEIS

Prepared by: Tom Myers

11/30/11

Introduction

The New York State Energy and Resource Development Agency (NYSERDA) commission Alpha Geosciences (Alpha) to complete a review of the comments I had prepared for the 2009 Draft Supplemental Generic Environmental Impact State (DSGEIS). This report replies to some of those review comments. Throughout, I refer to the review as "Alpha".

General Points

Alpha divided my comments into various subsets for their response, but they rely very much on several points throughout their response. One is their perception of there being no hydraulic connection between groundwater at depth, in the Marcellus shale, and the near-surface aquifers; they also dismiss the analysis from ICF (2009) on the same basis, even though they have no data with which to dismiss the argument. Their second line of reasoning is the results or conclusions from the 2004 EPA study of coal bed methane fracking.

Alpha rejects the suggestion that a water balance for the project area or subareas "would not serve the purpose of the SGEIS" (Alpha, at 4). They provide no reason for this conclusion, but also state that a "water balance clearly is site-specific" (Id.). A water balance can be useful for any size study area or portion of the study area. A water balance for the overall study area would help to understand the total volume of water involved in fracking; a similar argument can be made for a watershed – a water balance for the groundwater would help to understand whether the water amounts used for fracking is a substantial portion of the local water balance.

Alpha partially rejects my suggestion that a better description of the area's hydrogeology is needed by quoting my statement that "the Marcellus Shale is 'notoriously heterogeneous'" (Alpha, at 4). The request for a better description pertains to the overall area, not specifically the Marcellus shale. Additionally, the statement supports the concept that reported permeability values for the shale may not be representative and that broader scale description are required.

Hydraulic Connection between Shale and Surface

Alpha argues that the "target shales exist as an isolated system from the overlying fresh water-bearing units" (Alpha, at 4). "Isolated" overstates the case even for natural conditions, although the connection may be limited, as I accepted in 2009. Alpha claims that the "shales … are not part of, and are not connected to, the regional hydrogeological systems. Their baseline geologic evidence that fluid

migration to overlying fresh water aquifers is improbable includes studies that show the Marcellus shale has remained isolated from overlying formations for millions of years" (Alpha, at 5). Alpha does not directly provide citations for these "studies", but in the next sentence references the "facts that these units are 'overpressured' and that natural gas and saline water has remained trapped … for millions of years" (Id.) to two industry studies and the GEIS. This all ignores the science, cited in Myers (in review) of the upward movement and artesian pressure, observed during geothermal exploration, in formations above the shale. The salt in the shale may be the source of the salt in overlying formations, with the upward movement of salt balanced by the downward movement of freshwater recharge. This balance could be substantially upset by the changes wrought by fracking on the shale.

The "overpressuring" of the shale does not prove that the shale itself is isolated. Overpressuring is due to the gas being contained in the low permeability, very small pore spaces of the shale. Once fracked, the overpressuring may provide an initial source for water to flow into the formations above the shale.

The isolation argument is invoked again, by Alpha, at 11&12, 20, and 33.

My discussion relied and continues to rely for the 2011 rDSGEIS on the fact that fracking will change those conditions, changing the shale from an almost impervious aquitard into a low-conductivity formation; the previously isolated formation water will no longer be "isolated" because fracking fluid injection will push some into surrounding formations. The "overpressuring" in the shale may suggest that the shale itself is isolated at least in places. Myers' (2009 and in review) argument relies on the connection in the formation above the shale. Once fracked, the shale will have a much higher permeability so that fluids in the shale can move into surrounding formations within which the general groundwater flow will control.

Alpha refers to the fact that shallow water wells may be hydrofractured as "additional evidence that natural fractures and structures are not necessarily transmissive" (Alpha, at 4 and 37). This is a comparison of "apples and oranges". Hydrofracturing water wells may be done to increase their yield when screened in low-transmissivity formations; fracking water wells is done to increase the well yield from a few gallons per minute. The transmissivity of unfracked shale is orders of magnitude less than that in the formations in which a water well may have been screened. The cause for fracking in water wells differs from the cause for fracking a gas well; the comparison is irrelevant and proves nothing about the isolated nature of shale.

A further reliance on "overpressuring" is demonstrated (Alpha, at 5) where Alpha notes that eight research wells in the Marcellus shale had pressure gradients of 0.46 to 0.51 psia/ft when hydrostatic pressure is 0.433 psia/ft. That waters remain contained in the shale even with this overpressuring demonstrates their isolation. Once fracking hydraulically connects the shale with the overlying formations, the overpressuring is a source of pressure that would cause an upward gradient. The pressure would likely dissipate with time, but it would also cause an upward gradient after fracking.

Alpha indicates that my "hypothetical pathway … to ground water is along faults and fractures that intersect the Marcellus or induced fractures that extend beyond the target formation" (Alpha, at 5). This mischaracterizes the argument in two ways. First, it ignores the potential flow through the bulk media, through the primary porosity of the formations; this pathway would be slower, but flow is possible if there is a connection (Myers, in review) with the newly fractured shale. Myers (in review) found this flow to require from 100s to 1000s of years for contaminant transport. Second, natural faults and fractures do not have to "intersect" the shale, just reach its edge. Fluids within the shale would access the natural fractures above the shale, once fracked; the overpressuring would provide an added gradient for flow from the shale to surrounding formations, once fracking releases the fluids.

Alpha's second point is correct; out-of-formation fractures would provide an additional pathway. Although Alpha continues to suggest that out-of-formation fracking is rare, in their view, more current evidence is that it occurs frequently and extends as much as 2000 feet above the target formation (Fischer 2010); Alpha even references a personal communication from Fisher (Alpha, at 24) to recommend that the "SGEIS acknowledge that hydrofracturing has been shown to induce fractures beyond the target formation" (Id.). It appears that Alpha is not familiar with up to date literature or science.

Alpha rejects the "suggestion of 'head level maps'" that I had suggested in 2009 based on their rejection of the concept of saturated conditions from the "top of the target zone to the land surface" (Alpha, at 20). If there is no connection, groundwater levels will show nothing. They also note the isolation argument (at 20, 21) to reject the need for head level maps. Head level maps as recommended by Myers (2009) would confirm or deny the presence of upward head gradients in the formations above the shale. Once released by fracking, contaminants could advect along the flow paths which would be delineated by the hydraulic gradient. Although the fracking itself will change the gradient and potentially increase the potential upward flow, mapping the groundwater levels would assist the NYSDEC in determining where transport is possible. Alpha's recommendation is to basically ignore science and ignore the possibility of upward flow. Alpha replied to my comment suggesting that the rDSGEIS discuss properties resulting from fracking by discussing the direction that fractures would take in the shale (Alpha, at 15). My comments indicated that the rDSGEIS should include hydrogeologic properties, therefore Alphas reply was not responsive to the comment. Alpha's response that my "argument that the fractures will extend to and connect overlying fractures or paleofractures contradicts rock mechanics principles and field observations" is countered by the recent data in Fisher (2010) showing out-of-formation fracking. Alpha is unclear and provides no references as to how the comments contradict "rock mechanics principles".

I had also recommended that the NYSDEC require the industry to monitor post fracking shale properties. Alpha states that "[f]racture monitoring is required by the Proposed Supplementary Permit Conditions … (#33 and #34)" (Alpha at 16). That is incorrect; those permit conditions require the driller report on recorded operations during fracking, including pressure and the amount of injected, but that is not the same thing as doing post-frack monitoring, which could include microseismic surveys or core sampling. They also suggest that "[f]racture monitoring also can be evaluated on a well-specific basis using the

same criteria as the requirement to collect core samples and well logs" (Alpha, at 16). Those requirements are for pre-fracking conditions, not post-fracking.

Myers' Groundwater Modeling and ICF Analytical Modeling

I prepared (Myers 2009) an interpretative numerical groundwater model to consider whether and over what time frame flow could occur from the shale to freshwater aquifers. The "theory supporting Myers' model" is NOT from Hill and Tiedeman (2007) (Alpha, at 23). The reference is to the concept of "interpretative" modeling as opposed to a calibrated, predictive model. "Myers acknowledges that his model is not calibrated and cannot be used for predictive purposes" (Alpha, at 12). An interpretative model is not used for prediction, so Alpha's attack on the model is an attack here is irrelevant. The model does assume that the interburden between the ground surface and top of the shale is saturated, but not through the "isolated shale gas formations" (Id.). Again, the modeling is of the interburden and the shale, once it is fracked to its edge or beyond, is a boundary or a source of both fluids and contaminants. Or, flow through the shale is estimated based on its extremely low in-situ conductivity.

The numerical model I used in 2009 was not "to support [my] opinion" (Id.) but to test my conceptualization as to whether the flow was possible and under what conditions. Alpha criticizes the fact the model "oversimplifies ground water flow and transport". All groundwater models simplify flow; simple applications of Darcy's law are the most oversimplified analyses. The addition of secondary permeability, or fracture flow, to a contaminant transport analysis usually increases the rate that contaminants move, thus my estimated times should be low.

Alpha asserts that my "offered alternate model is not technically defensible" apparently based on their perceived lack of a hydraulic connection. They state that an assumption of a hydraulic connection "contradicts decades of hydrofracturing data and experience in the U.S." (Alpha, at 11) without referencing or outlining the data in support of their contention. They also claim that my analysis is based on "the entire bedrock stratigraphic column [being] highly fractured" (Alpha, at 12). This statement does not reflect the analysis in Myers (2009), for reasons noted above - the conductivity values used for the formations between the shale and surface were based on observed primary conductivity values (Anderson Woessner 1992), not fractured values.

ICF's flow equations are correct (Alpha at 11), but the problem is how they were parameterized and time frame they were applied over. As Myers (2009) discussed, the relevant gradient is not from the well to the aquifers, but from the well to just beyond the influence of the spreading injected fracking fluid, the point at which the background pressure has not changed. Also, the conductivity parameters for the formations between the shale and the aquifers do not reflect fractures, unless specifically parameterized as such. The parameters reflect standard textbook bulk conductivity values for sandstone.

Vertical Contaminant Transport

I had argued that "natural gradients" would allow vertical contaminant transport of frack fluid through advection. Alpha claims that "Engelder refutes that injected frac water would migrate vertically upward

in his slide-presentation review of others” (Alpha, at 24). Aside from the confusing phrase, “slide-presentation review of others”, this line of reasoning cannot be correct because frack fluid is lighter than the high-TDS brine found in the shale; buoyancy due to frack fluid being lighter than brine would enhance its upward movement. The movement of high-TDS formation water could be inhibited by its denser nature, but the point is that upward hydraulic gradients cause the flow. The overpressuring discussed above is proof of these upward gradients and suggestive that fracking would release some of this pressure into the formations lying above.

Engelder’s “principle of viscosity” (Id.) may apply “to ground water as well as gases”, but the fact that low viscosity gases have been contained from vertical migration for millions of years does not mean that fracking will not release contaminants that could migrate upward much quicker. The relevant “containment” is provided in the shale and has nothing to do with the properties of overlying formations. Shale has contained gas for millions of years; fracking will cause that gas to be released in 30 to 50 years (the length of time most wells will produce). This can only occur if the properties that contain the gas will vastly change.

Leaks from Well Bores

The DSGEIS had implied that leaks do not occur from properly-constructed wells, but did not specify how often wells are found to not be properly constructed, and I requested (Myers 2009) that they provide an estimate of the times the wells are not properly constructed. Alpha responded with a quote from an industry source that estimated risk from failures to properly constructed wells is less than one in 50 million (Alpha, at 32). Alpha should have included the entire paragraph from which they selectively chose their quote, because it indicates the wells considered are class II injection wells and are properly constructed. Fracking wells experience a much higher, although much shorter, pressure during operations. They also should realize that the comment had to do with wells that are improperly constructed, because most failures, those that have allowed gas into groundwater, have resulted from improperly constructed wells.

Alpha also protests too much when they discuss my examples of gas in water wells (Alpha, at 33, 34). Incidents not related specifically to fracking are relevant because they show that the gas does move long distances through the groundwater, regardless of the source. Coal bed methane development relies on the gas moving through the groundwater, in coal seams, to the production wells; those production wells commonly pump as much water as do water wells, so, if gas is present to move to the water wells, the conceptual model for flow to water wells is similar. The point has to do with gas moving through aquifers due to any source – direct from the shale or a leak from the well bore.

Comparison to CBM Wells

Alpha used the conclusion to the EPA’s 2004 CBM study, that fracking in coal seams poses little or no threat to underground sources of drinking water (Alpha, at 20) to support their conclusion that I had ignored relevant data (EPA’s study) and that my arguments were fallacious because CBM wells are a much higher risk. They also state that “[c]oalbed hydrofracturing events approximate conditions where shale hydrofracturing is performed closest to ground water resources” (Id.). This is simply not true, and

it directly contradicts the conditions that the EPA put on their conclusion. EPA relied on the nature of CBM wells for their conclusion. "Although potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are injected into coal seams that lie within USDWs, the risk posed to USDWs by introduction of these chemicals is **reduced significantly by groundwater production and injected fluid recovery**, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation" (EPA, 2004, at 7-5, emphasis added).

In fracked shale, there is no intentional "injected fluid recovery" brought about by pumping the injection wells, as in CBM wells. CBM wells pump water toward the gas well; this pumping decreases the hydrostatic pressure which releases the gas from the coal. Water and contaminants in the coal seam flows toward the CBM well. If there were contaminants in the coal, they would be drawn toward the CBM well.

Fracking in a coal seam would require much less pressure as well which would cause less out-of-formation fractures, which would limit the chance for out-of-formation fractures to occur. Additionally, EPA relies on the "high stress contrast between adjacent geologic strata" as a barrier to fracture propagation. The fact the coal is softer and the seams are much shallower and require much less fracking pressure helps to limit the fractures to the coal, much in contrast to shale seams (Fisher, 2010).

Finally, although the EPA's reasoning is reasonable, their methodology for concluding there has been no contamination is suspect; they only considered reported cases of contamination rather than relying on monitoring data. Fracking fluids in water wells near coal seams would be reported only if someone detects a problem. There have been cases of methane reaching water wells in the coal seams, but methane is obvious as it bubbles coming from the faucet.

Alpha claims that "Myers fails to address the historical data presented by ICF (2009, p. 22)" (Alpha at 19). ICF (2009, p 22) does not actually present data, contrary to Alpha's allegation. GWPC (1998), the source of ICF's "data", presents the results of a survey to which officials from states with over 10,000 coal-bed methane wells had responded they had never found groundwater contamination. However, contrary to Alpha's allegation, GWPC did not analyze 10,000 wells' worth of data. GWPC does not present monitoring data as proof, they present survey data from agency personnel claiming there has been no reported contamination. There is no indication whether the agencies ever looked for contamination beyond the claims of well owners. ICF also notes that coal seams may be used as aquifers, but did not indicate how many of the coal seams being developed by the CBM wells in the states replied to by the agency personnel were also aquifers.

Alpha truly mixes apples and oranges by using studies of CBM development, including fracking, to conclude that shale-gas development poses no threat to groundwater.

General Hydrogeology

Alpha's response to comments regarding aquifer depletion is a stretch to show how they actually disagree with my comments. Specifically, my comments about failures to regulate are replied to by stating the various commissions must permit the withdrawal – the problem is that there are really no

specifics provided about how the decision to permit would be granted. The DSGEIS did not specify what standard had to be met, beyond simple reporting, to be granted a permit.

Mitigating Surface Water Impacts

Alpha goes out of its way to find something to criticize in its review of my general surface water comments (Alpha, at 44, 45). My comments were generally qualitative and Alpha's responses are generally not substantial enough to require a reply here.

In Alpha section 4.2, regarding the use of the natural flow regime method, Alpha states that I was incorrect in claiming the NYSDEC would not require its use (Alpha, at 48). The 2011 rDSGEIS states clearly that it is NYSDEC's intent to require use of the NFRM, but the 2009 DSGEIS only states that it is "preferred", not required (2009 DSGEIS, at 7-3).

Alpha responds in detail to my comments regarding the Delaware and Susquehanna River Basin Commissions' methods (Alpha at 46, 47), even though they acknowledge the dSGEIS would require the NFRM. Because the rDSGEIS states the NFRM will be used throughout the project area, there is little reason to reply further to Alpha's comments at this point.

Ultimately, Alpha adapts many of my recommendations regarding surface water flow (Alpha, at 50, 51). They do not specifically endorse the recommendation to minimize the effect on aquatic habitats (outlined at Alpha, p. 47), the RDSGEIS does adapt a recommendation for using the Q60 or Q75 flow by month, which by month is better than my original recommendation.

Setbacks

Alpha discusses vertical setbacks along with my comments on monitoring and the need for water level mapping (Alpha, section 3.1). Much of their response relies on their perceived lack of hydraulic connection among formations, which has been discussed above.

Regarding horizontal setbacks, I had suggested that the recommended values are not based on any data or analysis of their effectiveness. Alpha simply rejects this without providing any reference, data, or results. "Myers assumes the setbacks proposed in the dSGEIS are not based on analysis; however, the setbacks are supported by practical application, experience, and historical analyses" (Alpha, at 43). Alpha repeats this sentence twice, verbatim, on the same page. When stating something as being based on analyses, it is customary scientific practice to cite the references to these analyses, something Alpha has failed to do. Alpha also suggests the "dSGEIS reference SEQRA, NYSDOH, NYC Watershed Rules and Regulations, the Clean Water Protection Act, and public water protection rules from other states" (Id.). Alpha does not indicate where in the dSGEIS these references are made, not indicates that the references include any analysis. Referencing others' rules without analyzing their effectiveness is not a scientific justification for specifying a setback. My statements are not that the setbacks are wrong, but that it is unknown whether they are effective. My recommendations may be larger than those in the dSGEIS, but they are designed to be protective to encourage a site specific analsis.

References

(Alpha) Alpha Geoscience, Inc. 2011. Review of dSGEIS and Identification of Best Technology and Best Practices Recommendations, Tom Myers; December 28, 2009. Prepared for NYSERDA, Albany NY.

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ICF International, 2009. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program Well Permit issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs. Agreement No. 9679, NYSERDA, Albany NY. August 7, 2009.

Perry, R., and Henry, B., July 1, 2010. Letter and attachment from Interstate Oil & Gas Compact Commission to Jeff Bingaman and Henry A. Waxman.

USEPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* EPA 816-R-04_003, June 2004. http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_coalbedmethanestudy.cfm.

EXHIBIT B

Pneumatic Controllers

Pneumatic controllers actuated by natural gas released to the atmosphere that are located at oil or natural gas production facilities, natural gas gathering or transmission compressor stations, or natural gas processing plants are subject to this regulation.

(1) All new and existing pneumatic controllers that emit natural gas to the atmosphere, whether emitting continuously or intermittently, shall emit hydrocarbons at levels equal to or less than a low-bleed pneumatic controller. In the case of existing pneumatic controllers, owners/operators must complete the replacement or retrofit by [date one year after effective date of this regulation].

(2) Where on-site electrical power, serviced by the grid, is used, an owner/operator shall not use pneumatic controllers that emit natural gas to the atmosphere.

(3) To obtain an exemption from [(1) and (2)], the owner/operator must submit justification that the high-bleed controller, or an intermittent-bleed pneumatic controller that is designed to have a bleed rate greater than a low-bleed, must be used or remain in service due to safety and/or process purposes by (a) one month after the effective date of this regulation for controllers in operation prior to [date of adoption], or (b) at least 30 days prior to installation in the case of a new controller. The Michigan Department of Environmental Quality shall have 30 days to approve such justification, and any failure to act within that timeframe will be deemed an approval.

Definitions

<u>Low-Bleed Pneumatic Controller</u>: a pneumatic controller designed to emit natural gas to the atmosphere at a rate, averaged over time, of less than or equal to 6 standard cubic feet per hour (scfh) of natural gas.

<u>High-Bleed Pneumatic Controller</u>: a pneumatic controller designed to emit natural gas to the atmosphere at a rate, averaged over time, of more than 6 scfh of natural gas.

Leak Detection and Repair

Operators of well production facilities and natural gas gathering and transmission compressor stations must do the following:

(1) Inspect components for leaks using one of the following approved monitoring methods for an initial inspection, unless the operator demonstrates that such monitoring is unsafe or the components are inaccessible:

- EPA Method 21.
- Infra-red camera.

Use of Auditory, Visual, Olfactory (AVO) is permissible for subsequent inspections, but not the initial survey.

(2) Perform such component leak surveys at the following frequencies:

- 0 < PTEH ≤ 12 tpy = Annual Inspection with monthly AVO
- 12 < PTEH ≤ 50 tpy = Quarterly Inspection with monthly AVO
- 50 < PTEH = Monthly Inspection

(3) Perform repairs as follows:

- Make the first attempt to repair any identified leak within 5 days of discovery.
- If parts to repair the leaking component are unavailable, order such part as soon as possible after discovery and make the repair within 15 days.
- If shutdown is required, repair the leak during the next scheduled shutdown.
- If other good cause is shown for delay in repair, repair the leak within 15 days after the cause of delay ceases to exist.
- Remonitor the leaking component within 15 days of repair to verify the repair was successful.

Definitions

“Leaks” means the following for purposes of Section XX:

(a) if using EPA Method 21, a concentration of *hydrocarbons* (including methane and ethane) > 2,000 ppm for facilities constructed prior to XX [date of adoption] and 500 ppm for facilities constructed thereafter.

(b) if using an infrared camera, any detectable emissions not associated with normal equipment operation.

“PTEH” means the following for purposes of Section XX: the source’s potential to emit hydrocarbons, including ethane and methane, using the definition of potential to emit contained in R 336.1116(n).

EXHIBIT C

Induced Seismicity

Proposed Regulation: Not applicable.

Comment: The proposed regulations do not address the potential for induced seismicity related to well stimulation, including hydraulic fracturing or include requirements for the operator to examine and mitigate the potential impact. Hydraulic fracturing has been confirmed or is suspected as the cause of induced seismicity strong enough to be felt at the surface in a number of incidents.

- In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Shortly after several stages of the Preese Hall 1 well were fracture stimulated, 50 seismic events were observed with a maximum magnitude of 2.3 M_L.[1]

- A report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8 M_L, could have been induced by hydraulic fracturing.[2]

- A total of 38 seismic events were recorded by the Canadian National Seismograph Network (CNSN) in the Etsho and Tattoo areas of the Horn River Basin between 2009 and 2011, ranging in magnitude from 2.2 to 3.8 M_L. After reviewing the locations, depths, and magnitudes of the earthquakes and comparing them to the timing and location of hydraulic fracturing, the researchers concluded that fracturing resulted in slippage along pre-existing faults, which caused the earthquakes. In all but one case, the earthquakes occurred along faults that had not previously been mapped.[3]

Induced seismicity can result in environmental and human health impacts identical to those caused by natural earthquakes of similar intensity, including the potential for property damage and injury. Earthquakes may also result in changes to groundwater or surface water level or quality.[4] Seismicity can also compromise wellbore integrity by damaging the cement sheath and metal casing installed as pressure control and ground water protection barriers. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250 foot length.[5] Deformation of the metal casing wall may crack inflexible cement that is placed in the annulus between the metal casing and the wellbore. Damage to the cement bond could allow fluids (gas and liquids) to migrate upwards and potentially contaminate the groundwater it was intended to protect. Even in the absence of actual damage, induced seismic events can be a nuisance to communities and a source of anxiety and may have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

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[1] de Pater, C.J., and Baisch, S. (2011), *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd, 71p.

[2] Holland, A. (2011), *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey, Open-File Report OF1-2011, 31p.

[3] BC Oil and Gas Commission (2012), Investigation of observed seismicity in the Horn River Basin, 29 p.

[4] See, e.g. Fleeger, G. M., Goode, D. J., Buckwalter, T. F., & Risser, D. W. (1999).*Hydrologic effects of the Pymatuning earthquake of September 25, 1998, in northwestern Pennsylvania*. US Department of the Interior, US Geological Survey.; King, C. Y., Zhang, W., & Zhang, Z. (2006). Earthquake-induced groundwater and gas changes. *pure and applied geophysics*, *163*(4), 633-645.

[5] *Ibid.* fn. **Error! Bookmark not defined.**.

We recommend that EQB, in consultation with the Pennsylvania Geological Survey, develop regulations to address induced seismicity. Operators should be required to evaluate seismic risk and the potential for induced seismicity at a proposed well site. This should include an analysis of background seismicity, local geology including faults and tectonically active features, local and regional stress state, proposed stimulation practices, and nearby instances of induced seismicity. This should also include: an evaluation of the maximum magnitude of an earthquake that could be induced based on anticipated injection volume;[6] the probability that such an earthquake may occur, based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, minimum horizontal stress; and anticipated pore pressure as a result of fluid injection.[7] The results of this evaluation should be provided with the permit application.

Researchers at Lawrence Berkeley National Laboratory[8] and the National Academy of Sciences[9] have published detailed information on the elements that should be considered for inclusion in a protocol for addressing induced seismicity, including but not limited to:

- Plans for outreach and communication with the public, regulators, and other stakeholders about seismic hazard, mitigation, and any incidents of induced seismicity. This includes involving stakeholders at all phases of the project, providing meaningful opportunities for input, and being responsive to stakeholder questions and concerns.

- Selecting criteria for damage, vibration, and noise to assess the potential impact of induced seismicity on the built environment and human activity. This includes identifying thresholds for damage to structures, ground shaking, and noise, below which no impact would occur. At a minimum, impact criteria should be evaluated for: buildings; civil structures such as bridges, highways, tunnels, etc.; buried structures such as wells, pipelines, and basement walls; landslides; human response to vibration and noise; and laboratory and manufacturing facilities, particularly those with equipment that may be sensitive to ground vibration.

- An assessment of site-specific natural and induced seismic hazard. This may include both probabilistic and deterministic seismic hazard assessments. The analysis of natural seismicity hazard will serve as a baseline against which to compare induced seismicity hazard and should include an evaluation of the seismic history of the region, fault identification and characterization, geologic site characterization, ground motion models, and the generation of hazard curves and maps. The induced seismicity hazard assessment may include an evaluation of local geology and existing seismic monitoring data, review of known instances of induced seismicity, available predictive models for induced seismicity maximum magnitude, ground motion models, and the generation of hazard curves and maps. Limited data may be available to evaluate induced seismic

[6] See, e.g. McGarr, A. (2014). Maximum magnitude earthquakes induced by fluid injection. *Journal of Geophysical Research: Solid Earth*.; Hallo, M., Oprsal, I., Eisner, L., & Ali, M. Y. (2014). Prediction of magnitude of the largest potentially induced seismic event. *Journal of Seismology*, 1-11.

[7] See, e.g. Shapiro, S. A., Dinske, C., & Kummerow, J. (2007). Probability of a given-magnitude earthquake induced by a fluid injection. *Geophysical research letters*, *34*(22).

[8] See, e.g. Majer, E., Nelson, J., Robertson-Tait, A., Savy, J., & Wong, I. (2012). Protocol for addressing induced seismicity associated with enhanced geothermal systems. *US Department of Energy*.; Majer, E., Nelson, J., Robertson-Tait, A., Savy, J., & Wong, I. (2013). Best Practices for Addressing Induced Seismicity Associated With Enhanced Geothermal Systems (EGS). *US Department of Energy*.

[9] Clarke, D., Detournay, E., Diederich, J., Dillon, D., Green, S., Habiger, R., ... & Smith, J. (2012). *Induced seismicity potential in energy technologies*. National Academies Press.

hazard and therefore it is critical that these assessments be updated as additional data become available.

- Probabilistic and scenario risk assessments. Several different scenario assessments may be appropriate but at a minimum should include a "worst case" scenario analysis. These analyses should include: vulnerability assessments for possible receptors including residential and community buildings; commercial, industrial, research, and medical facilities; infrastructure; socioeconomic impacts, including business disruptions; and, nuisance due to vibration or noise. Particular attention should be paid to older structures, and plugged and abandoned wells. The costs of consequences should also be evaluated, including monetary costs due to physical damage or loss as well as non-physical damages such as nuisance. Risk should be assessed for both natural and induced seismicity to enable comparisons.

- Seismic Monitoring. This includes real-time seismic monitoring before, during, and after stimulation activities. The design and placement of the monitoring array should at a minimum take into account the location of potential seismic sources and background seismicity, the location of sensitive receptors, depth and seismic properties of the formation that will be fractured, necessary sensitivity, and predicted size of the fracture network.

- A mitigation plan, based on the hazard and risk assessments. If necessary, based on the results of the hazard and risk assessments, the proposed hydraulic fracture design should be revised to control the level and impact of induced seismicity. Operators should also develop an appropriate "traffic light" control system for responding to an instance of induced seismicity. Under a traffic light system, increases in induced seismic activity beyond predetermined thresholds trigger actions by the operator, which may include additional monitoring, reducing injection volume or pressure, or ceasing operations completely. Thresholds may be based on earthquake magnitude, intensity of ground motion, or other measures. The threshold levels and required actions by operators when those thresholds are exceeded must be developed based on site-specific conditions.

Subsurface waste water injection has also been documented to cause induced seismicity.[10] While recognizing that PADEP does not have primacy to implement the Underground Injection Control (UIC) program, we encourage PADEP to coordinate with EPA Region 3 on addressing the risk of induced seismicity from Class II disposal wells. The same elements listed above should be considered for inclusion in a protocol to address induced seismicity from disposal wells.

In sum, we recommend that the EQB, in consultation with the Pennsylvania Geological Survey, develop regulations to address the risk of induced seismicity from hydraulic fracturing. The regulations should include requirements for Operators to: 1) develop a stakeholder communications and outreach plan; 2) determine criteria for ground vibration and noise; 3) perform a hazard assessment; 4) perform a risk assessment; 5) conduct seismic monitoring, and; 6) develop mitigation plans. These elements should be developed using the operator's proposed hydraulic fracture design for that well along with site-specific data. Additional information and guidance on developing an appropriate protocol is available in the publications cited in the footnotes to this comment.

[10] See, e.g. Sumy, D. F., Cochran, E. S., Keranen, K. M., Wei, M., & Abers, G. A. (2014). Observations of static Coulomb stress triggering of the November 2011 M5. 7 Oklahoma earthquake sequence. *Journal of Geophysical Research: Solid Earth*.; Ellsworth, W. L. (2013). Injection-induced earthquakes. *Science*, *341*(6142).

EXHIBIT D

Tom Myers, Ph.D.
Consultant, Hydrology and Water Resources
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Reno, NV 89523
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Curriculum Vitae

Objective: To provide diverse and independent research and consulting services to nonprofit, government, legal and industry clients in hydrogeology, groundwater modeling, and water quality with a focus on compliance, NEPA analysis, federal and state regulatory review, and environmental and water policy. There is a particular focus on mining, natural gas development, and water rights issues.

Education

Years	Degree	University
1992-96	Ph.D. Hydrology/Hydrogeology	University of Nevada, Reno Dissertation: Stochastic Structure of Rangeland Streams
1990-92		University of Arizona, Tucson AZ Classes in pursuit of Ph.D. in Hydrology.
1988-90	M.S. Hydrology/Hydrogeology	University of Nevada, Reno Thesis: Stream Morphology, Stability and Habitat in Northern Nevada
1981-83		University of Colorado, Denver, CO Graduate level water resources engineering classes.
1977-81	B.S., Civil Engineering	University of Colorado, Boulder, CO

Professional Experience

Years	Position	Duties
1993-Pr.	Hydrologic Consultant	Surface, groundwater and systems modeling, hydrogeology studies, stream restoration design, watershed modeling studies and expert testimony for industry, nonprofit groups, and government agencies.
1999-2004	Great Basin Mine Watch Executive Director	Responsible for reviewing and commenting on mining projects with a focus on groundwater and surface water resources, preparing appeals and litigation, writing reports about mining, fundraising, organizational development, supervision and personnel management.
1992-1997	University of Nevada, Reno Research Associate	Research on riparian area and watershed management including stream morphology, aquatic habitat, cattle grazing and low-flow and flood hydrology.
1990-1992	University of Arizona, Tucson Research and Teaching Assistant	Research on rainfall/runoff processes and climate models. Taught lab sections for sophomore level "Principles of Hydrology". Received 1992 Outstanding Graduate Teaching Assistant Award in the College of Engineering
1988-	University of	Research on aquatic habitat, stream morphology and livestock

1990	Nevada, Reno Research Assistant	management.
1983-1988	US Bureau of Reclamation, Boulder City, NV Hydraulic Engineer	Performed hydrology planning studies on topics including floodplains, water supply, flood control, salt balance, irrigation efficiencies, sediment transport, stream morphology, flood frequency, rainfall-runoff modeling and groundwater balances.
1981-1983	Faulkner-Kellogg and Assoc., Lakewood Co Design Engineer	Basic drainage, grading and subdivision design. Flood control studies.

Peer-Reviewed Publications

Myers, T., 2013. Remediation scenarios for selenium contamination, Blackfoot Watershed, southeast Idaho, USA. *Hydrogeology Journal* 21: 655-672. DOI 10.1007/s10040-013-0953-8

Myers, T., in press. Reservoir loss rates from Lake Powell and their impact on management of the Colorado River. *Journal of the American Water Resources Association*.

Myers, T., 2012. Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water* 50(6):872-882 doi: 10.1111/j.1745-6584.2012.00933.x

Myers, T., 2009. Groundwater management and coal-bed methane development in the Powder River Basin of Montana. *J Hydrology* 368:178-193.

Myers, T.J. and S. Swanson, 1997. Variation of pool properties with stream type and ungulate damage in central Nevada, USA. *Journal of Hydrology* 201-62-81

Myers, T.J. and S. Swanson, 1997. Precision of channel width and pool area measurements. *Journal of the American Water Resources Association* 33:647-659.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of pool-to-pool structure in small Nevada rangeland streams. *Water Resources Research* 33(4):877-889.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of transect-to-transect properties of Great Basin rangeland streams. *Water Resources Research* 33(4):853-864.

Myers, T.J. and S. Swanson, 1996. Long-term aquatic habitat restoration: Mahogany Creek, NV as a case study. *Water Resources Bulletin* 32:241-252

Myers, T.J. and S. Swanson, 1996. Temporal and geomorphic variations of stream stability and morphology: Mahogany Creek, NV. *Water Resources Bulletin* 32:253-265.

Myers, T.J. and S. Swanson, 1996. Stream morphologic impact of and recovery from major flooding in north-central Nevada. *Physical Geography* 17:431-445.

Myers, T.J. and S. Swanson, 1995. Impact of deferred rotation grazing on stream characteristics in Central Nevada: A case study. *North American Journal of Fisheries Management* 15:428-439.

Myers, T.J. and S. Swanson, 1992. Variation of stream stability with stream type and livestock bank damage in northern Nevada. *Water Resources Bulletin* 28:743-754.

Myers, T.J. and S. Swanson, 1992. Aquatic habitat condition index, stream type, and livestock bank damage in northern Nevada. *Water Resources Bulletin* 27:667-677.

Zonge, K.L., S. Swanson, and T. Myers, 1996. Drought year changes in streambank profiles on incised streams in the Sierra Nevada Mountains. *Geomorphology* 15:47-56.

Representative Reports and Projects

Myers, T., 2013. Preparation of comments on Proposed Hydraulic Fracturing Regulations. Prepared for Natural Resources Defense Council, New York.

Myers, T., 2013. Preparation of testimony on drill pad waste disposal, New Mexico. Prepared for Oil and Gas Accountability Project.

Myers, T., 2012. Technical Memorandum, Review of the Special Use Permit PP2011-035-Camilletti 21-10, Groundwater Monitoring Requirements. Prepared for Route County Board of Commissioners and the Routt County Planning Department. June 19, 2012.

Myers, T., 2012. Testimony at Aquifer Protection Permit Appeal Hearing, Rosemont Mine. Phoenix AZ, August and September, 2012.

Myers, T., 2012. Drawdown at U.S. Forest Service Selected Monitoring Points, Myers Rosemont Groundwater Model Report. Prepared for Pima County, AZ. March 22, 2012.

Myers, T., 2011. Hydrogeology of Cave, Dry Lake and Delamar Valleys, Impacts of pumping underground water right applications #53987 through 53092. Presented to the Office of the Nevada State Engineer On behalf of Great Basin Water Network.

Myers, T., 2011. Hydrogeology of Spring Valley and Surrounding Areas, Part A: Conceptual Flow Model. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Hydrogeology of Spring Valley and Surrounding Areas, Part B: Groundwater Model of Snake Valley and Surrounding Area. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Hydrogeology of Spring Valley and Surrounding Areas, PART C: IMPACTS OF PUMPING UNDERGROUND WATER RIGHT APPLICATIONS #54003 THROUGH 54021. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Rebuttal Report: Part 2, Review of Groundwater Model Submitted by Southern Nevada Authority and Comparison with the Myers Model. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T. 2011. Rebuttal Report: Part 3, Prediction of Impacts Caused by Southern Nevada Water Authority Pumping Groundwater From Distributed Pumping Options for Spring Valley, Cave Valley, Dry Lake Valley, and Delamar Valley. Presented to the Nevada State Engineer on behalf of Great Basin Water

Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Baseflow Selenium Transport from Phosphate Mines in the Blackfoot River Watershed Through the Wells Formation to the Blackfoot River, Prepared for the Greater Yellowstone Coalition.

Myers, T., 2011. Blackfoot River Watershed, Groundwater Selenium Loading and Remediation. Prepared for the Greater Yellowstone Coalition.

Myers, T., 2010. Planning the Colorado River in a Changing Climate, Colorado River Simulation System (CRSS) Reservoir Loss Rates in Lakes Powell and Mead and their Use in CRSS. Prepared for Glen Canyon Institute.

Myers, T., 2010. Technical Memorandum, Updated Groundwater Modeling Report, Proposed Rosemont Open Pit Mining Project. Prepared for Pima County and Pima County Regional Flood Control District

Myers, T., 2009. Monitoring Groundwater Quality Near Unconventional Methane Gas Development Projects, A Primer for Residents Concerned about Their Water. Prepared for Natural Resources Defense Council. New York, New York.

Myers, T., 2009. Technical Memorandum, Review and Analysis of the Hydrology and Groundwater and Contaminant Transport Modeling of the Draft Environmental Impact Statement Blackfoot Bridge Mine, July 2009. Prepared for Greater Yellowstone Coalition, Idaho Falls, Idaho.

Myers, T., 2008. Hydrogeology of the Carbonate Aquifer System, Nevada and Utah With Emphasize on Regional Springs and Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C.. June 1, 2008.

Myers, T., 2008. Hydrogeology of the Muddy River Springs Area, Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C. May 1, 2008

Myers, T., 2008. Hydrogeology of the Santa Rita Rosemont Project Site, Numerical Groundwater Modeling of the Conceptual Flow Model and Effects of the Construction of the Proposed Open Pit, April 2008. Prepared for: Pima County Regional Flood Control District, Tucson AZ.

Myers, T., 2008. Technical Memorandum, Review, Record of Decision, Environmental Impact Statement Smoky Canyon Mine, Panels F&G, U.S. Department of the Interior, Bureau of Land Management. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV.

Myers, T., 2007. Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Proposed Panels F and G. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV. December 11, 2007.

Myers, T., 2007. Hydrogeology, Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Documentation of a Groundwater Flow and Contaminant Transport Model. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV, December 7, 2007.

Myers, T., 2007. Review of Hydrogeology and Water Resources for the Final Environmental Impact

Statement, Smoky Canyon Mine, Panels F and G and Supporting Documents. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno, NV. December 12, 2007.

Myers, T., 2007. Hydrogeology of the Powder River Basin of Southeast Montana Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council. February 12 2007.

Myers, T., 2007. Hydrogeology of the Santa Rita Rosemont Project Site, Conceptual Flow Model and Water Balance, Prepared for: Pima County Flood Control District, Tucson AZ

Myers, T., 2006. Review of Mine Dewatering on the Carlin Trend, Predictions and Reality. Prepared for Great Basin Mine Watch, Reno, NV

Myers, T., 2006. Hydrogeology of Spring Valley and Effects of Groundwater Development Proposed by the Southern Nevada Water Authority, White Pine and Lincoln County, Nevada. Prepared for Western Environmental Law Center for Water Rights Protest Hearing.

Myers, T., 2006. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs of the Pinnacle Gas Resource, Dietz Project In the Powder River Basin of Southeast Montana. Affidavit prepared for Northern Plains Resource Council, April 4 2006.

Myers, T., 2006. Review of Hydrogeology and Water Resources for the Draft Environmental Impact Statement, Smoky Canyon Mine, Panels F and G, Technical Report 2006-01-Smoky Canyon. Prepared for Natural Resources Defense Council.

Myers, T., 2006. Review of Nestle Waters North America Inc. Water Bottling Project Draft Environmental Impact Report / Environmental Assessment. Prepared for McCloud Watershed Council, McCloud CA.

Myers, T., 2005. Hydrology Report Regarding Potential Effects of Southern Nevada Water Authority's Proposed Change in the Point of Diversion of Water Rights from Tikapoo Valley South and Three Lakes Valley North to Three Lakes Valley South. Prepared for Western Environmental Law Center for Water Rights Protest Hearing

Myers, T., 2005. Review of Draft Supplemental Environmental Impact Statement, Ruby Hill Mine Expansion: East Archimedes Project NV063-EIS04-34, Technical Report 2005-05-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2005. Hydrogeology of the Powder River Basin of Southeast Montana, Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council, Billings, MT in support of pending litigation.

Myers, T., 2005. Nevada State Environmental Commission Appeal Hearing, Water Pollution Control Permit Renewal NEV0087001, Big Springs Mine. Expert Report. Prepared for Great Basin Mine Watch, Reno NV.

Myers, T., 2005. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs In the Powder River Basin of Southeast Montana. Prepared for Northern Plains Resource Council, Billings, MT.

Myers, T., 2004. An Assessment of Contaminant Transport, Sunset Hills Subdivision and the Anaconda Yerington Copper Mine, Technical Report 2004-01-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Memorandum: Pipeline Infiltration Project Groundwater Contamination. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Report Seepage From Waste Rock Dump to Surface Water The Jerritt Canyon Mine, Technical Report 2004-03-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2001. An Assessment of Diversions and Water Rights: Smith and Mason Valleys, NV. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrogeology of the Basin Fill Aquifer in Mason Valley, Nevada: Effects of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrology and Water Balance, Smith Valley, NV: Impacts of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV

Myers, T., 2000. Alternative Modeling of the Gold Quarry Mine, Documentation of the Model, Comparison of Mitigation Scenarios, and Analysis of Assumptions. Prepared for Great Basin Mine Watch. Center for Science in Public Participation, Bozeman MT.

Myers, T., 2000. Environmental and Economic Impacts of Mining in Eureka County. Prepared for the Dept. Of Applied Statistics and Economics, University of Nevada, Reno.

Myers, T., 1999. Water Balance of Lake Powell, An Assessment of Groundwater Seepage and Evaporation. Prepared for the Glen Canyon Institute, Salt Lake City, UT.

Myers, T., 1998. Hydrogeology of the Humboldt River: Impacts of Open-pit Mine Dewatering and Pit Lake Formation. Prepared for Great Basin Mine Watch, Reno, NV.

Selected Abstracts, Magazine and Proceedings Articles

Myers, T., 2012. Participation in: Keystone Center Independent Science Panel, Pebble Mine. Anchorage AK, October 1-5, 2012.

Myers, T., 2012. Mine Dewatering: Humboldt River Update. INVITED PRESENTATION at 2012 Nevada Water Resources Association Annual Conference.

Myers, T., 2012. Reservoir loss rates from Lake Powell, and long-term management of the Colorado River system. 2012 Nevada Water Resources Association Annual Conference

Myers, T., 2011. Reservoir loss rates from Lake Powell, and long-term management of the Colorado River system. 2011 Fall Conference, American Geophysical Union.

Myers, T., 2006. Modeling Coal Bed Methane Well Pumpage with a MODFLOW DRAIN Boundary. In MODFLOW and More 2006 Managing Ground Water Systems, Proceedings. International Groundwater Modeling Center, Golden CO. May 21-24, 2006.

Myers, T., 2006. Proceed Carefully: Much Remains Unknown, *Southwest Hydrology 5(3)*, May/June 2006, pages

14-16.

Myers, T., 2004. Monitoring Well Screening and the Determination of Groundwater Degradation, Annual Meeting of the Nevada Water Resources Association, Mesquite, NV. February 27-28, 2004.

Myers, T., 2001. Impacts of the conceptual model of mine dewatering pumpage on predicted fluxes and drawdown. In MODFLOW 2001 and Other Modeling Odysseys, Proceedings, Volume 1. September 11-14, 2001. International Ground Water Modeling Center, Golden, Colorado.

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Kendall, D.R. (ed.), Conjunctive Use of Water Resources: Aquifer Storage and Recovery. AWRA Symposium, Long Beach California. October 19-23, 1997

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Life in a Closed Basin, Nevada Water Resources Association, October 8-10, 1997, Elko, NV.

Myers, T., 1997. Uncertainties in the hydrologic modeling of pit lake refill. American Chemical Society Annual Meeting, Las Vegas, NV, Sept. 8-12, 1997.

Myers, T., 1997. Use of groundwater modeling and geographic information systems in water marketing. In Warwick, J.J. (ed.), Water Resources Education, Training, and Practice: Opportunities for the Next Century. AWRA Symposium, Keystone, Colo. June 29-July 3, 1997.

Myers, T., 1995. Decreased surface water flows due to alluvial pumping in the Walker River valley. Annual Meeting of the Nevada Water Resources Association, Reno, NV, March 14-15, 1995.

Special Coursework

Years	Course	Sponsor
2011	Hydraulic Fracturing of the Marcellus Shale	National Groundwater Association
2008	Fractured Rock Analysis	MidWest Geoscience
2005	Groundwater Sampling Field Course	Nielson Environmental Field School
2004	Environmental Forensics	National Groundwater Association
2004 and -5	Groundwater and Environmental Law	National Groundwater Association

BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL
September 2010 – Present

STAFF SCIENTIST

Technical advisor on issues related to oil and natural gas extraction and geologic sequestration of carbon dioxide. Provides scientific expertise and analysis in support of advocacy efforts. Identifies regulatory solutions and industry best practices to address the environmental impacts of oil and natural gas extraction Engages with and serves as a liaison to the scientific community.

ANADARKO PETROLEUM CORPORATION
January 2005 – September 2010

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – September 2010)
Senior Geologist & Team Lead

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO_2 Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)
Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO_2
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO_2 flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)
Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

ANADARKO PETROLEUM CORPORATION
The Woodlands, Texas

GEOSCIENCE INTERN
September 2004 - November 2004

Evaluated the Baxter shale in active Wyoming oil and gas fields for shale-gas production potential.

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL
Chapel Hill, North Carolina

MASTER OF SCIENCE, GEOLOGICAL SCIENCES
September 2002 – May 2005

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY
Boston, Massachusetts

BACHELOR OF ARTS, EARTH SCIENCE
September 1998 – May 2002

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

BRIANA E. MORDICK

PUBLICATIONS

Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: Contributions to Mineralogy and Petrology, v. 152, no. 1, p. 111-124.

SELECTED PRESENTATIONS

- October 19, 2010:
  - Forum: National Research Council of the National Academies, Board on Earth Sciences and Resources, Committee on Earth Resources
    - Meeting Title: "Meeting Our Nation's Natural Resource Needs: Balancing Risks and Rewards"
    - Presentation Title: "Environmental Impacts of Oil and Gas Production"
- March 11, 2011:
  - Forum: EPA Hydraulic Fracturing Study Technical Workshop
    - Meeting Title: Well Construction and Operations
    - Presentation & Abstract Title: "Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned"
- September 27, 2011:
  - Forum: University of Wyoming Hydraulic Fracturing Forum
    - Meeting Title: Hydraulic Fracturing, A Wyoming Energy Forum
    - Presentation Title: Hydraulic Fracturing Best Practices: Mitigating Environmental Concerns
- April 30, 2012
  - Forum: Eurasia Group Workshop
    - Meeting Title: US Unconventional Oil and Gas Resources: National Security Implications
    - Panel: Obstacles to US unconventional oil and gas development
    - Presentation Title: Environmental Impacts of Oil and Natural Gas Production
- June 25, 2012
  - Forum: NRDC Workshop on Shale Gas in China
    - Meeting Title: Workshop on Best Practices for Shale Gas Development in China: Policies and Technologies to Minimize Environmental Impacts
    - Presentation Titles: US Shale Gas Development Technologies and Experience; Best Practices for Minimizing Water Use and Pollution from Shale Gas Development
- March 15, 2013
  - Forum: Woodrow Wilson Center
    - Meeting Title: Shale Gas Revolution in China: Game Changer for Coal?
    - Presentation Title: Shale Gas Revolution in China: Game Changer for Coal?
- October 4, 2013
  - Forum: American Chemical Society, Western Regional Meeting
    - Meeting Title: Hydraulic Fracturing in California: Environmental Issues with the Largest Shale Oil Formation in the U.S.
    - Panel Discussion