2009 NYS DSGEIS

Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & 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

Review of DSGEIS and Identification of Best Technology and Best Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

December 28, 2009

Email: sharvey@mtaonline.net

Phone: (907) 694-7994
Fax: (907) 694-7995

PO Box 771026
Eagle River, Alaska 99577

Contents

Introduction

This analysis responds to the Natural Resources Defense Council's (NRDC) request for a review of the New York State (NYS) September 2009 *Draft Supplemental Generic Environmental Impact Statement* (DSGEIS) *on the Oil, Gas & 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.*

NRDC requested a technical review of the DSGEIS to determine if best technology and practices protective of the environment were included. NRDC and its partners have commissioned additional experts to make recommendations on the protection of other resources. Therefore this list of recommendations is not exhaustive, and is complementary to the work assigned to other experts reviewing the DSGEIS. A complete list of best technology and practices recommended by the experts can be found in the summary cover letter submitted by AKRF, Inc. to the New York State Department of Environmental Conservation (NYSDEC) during the DSGEIS public comment period.

This report makes recommendations for improving the NYS DSGEIS analysis. This report also makes recommendations for how to more formally adopt and require best practices in NYS regulations.

Specific recommendations are highlighted in a blue text box.

1. Scope of DSGEIS

Recommendation No. 1: The DSGEIS scope should be limited to analysis of the Marcellus Shale Gas Reservoir. The Marcellus Shale is a substantial accumulation, and warrants its own EIS analysis. Additional information and analysis is needed to examine the impacts of exploring and developing other low-permeability gas reservoirs.

NYSDEC proposes that the DSGEIS cover all horizontal drilling and high-volume hydraulic fracturing in all low-permeability gas reservoirs in NYS; yet, only the Marcellus Shale Gas Reservoir is studied in detail. The DSGEIS is incomplete for all other low-permeability gas reservoirs.

The DSGEIS provides some information on the Utica Shale Gas Reservoir (mostly in the form of geologic assessment), but it does not examine in detail the impacts of drilling or high-volume hydraulic fracture treatments on the Utica Shale or other low-permeability gas reservoirs in the region.

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are examined.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. Yet, Chapters 5 and 6 are essentially silent on how the Utica Shale Gas Reservoir would be developed. No other low-permeability gas reservoirs are examined.

Technical reports, which were provided by NYSDEC's consultants as supporting documents for the DSGEIS, focus on Marcellus Shale development; they do not provide technical data about or support for development of other low-permeability gas reservoirs in the region.

The Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir at its deepest point in southern NYS. The Utica Shale dips to 9,000' deep,[1] while the Marcellus Shale is approximately 5,000' deep.[2] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste. Utica Shale development will also require more resources and equipment. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact for a Utica Shale well.

Low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale were not studied in any detail, and there is insufficient information in this EIS to justify any development at this time.

Best technology and best practices, in many cases, are gas reservoir specific. Because the DSGEIS does not contain information on the depth, type, activity or equipment requirements for the general category in DSGEIS called "***other*** *low-permeability gas reservoirs*," it is not possible to determine if the maximum impact assessment for a Marcellus Shale well sufficiently covers the maximum impact from "***other*** *low-permeability gas reservoirs*." Nor is it possible to determine whether best technology and practices developed for the Marcellus Shale would apply.

Recommendation No. 2: There is insufficient data provided on the Marcellus Shale Gas Reservoir to support a statewide exploration and production plan. The dataset provided by NYSDEC, in this DSGEIS, is equivalent to early exploration. Additional information is needed to support site-specific production/development scenarios for the Marcellus Shale Gas Reservoir.

NYSDEC should consider either:

(1) Narrowing the scope of this DSGEIS to exploration activities, and baseline study work, and complete a separate future EIS when additional exploration data is available to support a production/development case; or

(2) Clearly outline in this DSGEIS the data set that must be obtained, and analyses that must be performed during exploration, to obtain sufficient information to support a production/development case. The DSGEIS should then establish a process for conducting a site-specific environmental assessment for each production/development well site based on that data collected during the exploration phase.

During the scoping analysis for this DSGEIS, the paucity of exploration data and baseline study work on the Marcellus Shale was not evident. NRDC, and its partners, supported alternatives to examine statewide production/development scenarios assuming exploratory work and baseline datasets were available to NYSDEC to support such an analysis. It was not until the DSGEIS was published in September 2009 that the paucity of data became patently obvious.

Not only is there insufficient exploration data and baseline study work to support a production/development case for the Marcellus Shale on a statewide basis, the DSGEIS also made it clear that there is insufficient infrastructure, support facilities, expertise and agency oversight systems in place to support large-scale, statewide development of the Marcellus Shale. While there may be small site-specific areas within NYS that have more tightly refined exploration data that could possibly support a small production/development case, this is certainly not true for all of NYS. The statewide dataset

[1] DSGEIS, p. 4-6.
[2] DSGEIS, p. 4-15.

provided by NYSDEC, in this first draft, is equivalent to early exploration; it does not support a statewide production/development plan.

NYS's attempt to complete a statewide EIS to cover all future Marcellus Shale gas development is an enormous task. The first draft of the DSGEIS clearly demonstrates that there is insufficient data to complete this analysis. Because there is insufficient data to support a high-quality, site-specific scientific and technical assessment of Marcellus Shale gas production/development scenarios on a statewide basis, NYSDEC should consider either limiting this DSGEIS to exploration activities or should establish a process whereby additional data can be collected during exploration to support future production/development proposals.

Gas resource development occurs in two distinct phases: (1) exploration and (2) production; commonly referred to as the upstream Exploration & Production (E&P) sector, to distinguish between downstream activities such as refining and marketing. Exploration activities are completed to locate the hydrocarbon resources and collect sufficient baseline data to determine whether the hydrocarbon resources can be safely, and economically, developed. Exploration typically includes single wells and numerous studies. Most commonly, an EIS is completed during the pre-exploration (leasing phase) to establish exploration limits, and to determine the baseline data that should be collected to guide future production/development opportunities. If data collected during exploration supports a production/development scenario, then larger scale production (multiple wells, on larger drill sites, and surface processing and distribution facilities) may be needed to develop the resource. Commonly, a full environmental assessment of the production/development scenario is the next step after exploration activities are completed. Site-specific production/development scenarios are typically prepared by the operator, in support of its proposed project, and are supported with high-quality, site-specific scientific and technical information to address the unique aspects of that project.

Because NYSDEC's DSGEIS attempts to combine both exploration and production approval into one EIS, substantially more information is required to support the EIS. And, in many cases, the data has not been collected because the exploratory work has not been completed. For this reason, the exploration and production EIS processes are very commonly separated throughout the United States. For example, the U.S. Minerals Management Service (MMS), which is responsible for developing all of the U.S. oil and gas resources in the Outer Continental Shelf, sets forth a two step process.[3]

- First, an environmental analysis is required to support the exploration phase. Based on that analysis and the sufficiency of the Exploration Plan prepared by the applicant, MMS issues an **Exploration Plan Approval** allowing operators to drill exploratory wells to delineate the oil and gas reservoir, and collect additional information that can support a Development and Production Plan and EIS.

- Second, an environmental analysis is required to support the production phase. Based on that analysis and the sufficiency of the Development and Production Plan, MMS issues a **Development and Production Plan Approval**.

Other oil and gas producing states, similarly, have regulations that provide for a step-wise approval process transitioning from leasing to exploration, and then to production and development. For example, Alaska follows a similar process as the MMS.[4] Alaska requires a Best Interest Finding document to be

[3] MMS Regulations for Oil and Gas and Sulphur Operations in the Outer Continental Shelf. 30 C.F.R. pt. 250, Exploration and development are defined in 30 C.F.R. § 250.105. See 43 U.C.S. § 1340 and 30 C.F.R. §§ 250.211 to .235; 250.280 to .285 for Exploration Plan requirements. See 43 U.S.C. § 1351 and 30 C.F.R. §§ 250.241 to .273; 250.280 to .285 for Development and Production Plan requirements.
[4] See 20 Alaska Admin. Code §§ 25.005, .990 (distinguishing exploration and development wells).

prepared before an area is even leased.[5] This is essentially a state EIS process conducted prior to exploration. Once the leases are sold by the state, an exploration permit can be obtained to just drill the exploration wells and conduct studies.[6] Drilling additional wells, and developing surface facilities requires a development plan and full environmental assessment (operators must put a complete package together from drilling and all the surface facilities right up to where they connect into a sales line).[7] This stepwise approach allows for responsible development to proceed in areas where there is sufficient data to support the project, and requiring additional study and exploration in areas that are not well understood.

While state regulations vary in procedural detail, this same basic approach is common, allowing exploratory operations to collect sufficient data to support a thorough, high-quality production and development assessment. If there is sufficient information available to support both exploration and production, it may be possible to permit both simultaneously, but this approach is uncommon.

NYSDEC's attempt to combine both exploration and production operations into one analysis has complicated the assessment and created an unmanageably large and complex analysis that is unsupported by the limited amount of currently available data.

While the lack of data on the Marcellus Shale may have been self evident to NYSDEC, it was not to the public, and NYSDEC should have disclosed this problem during scoping, allowing other alternatives to be considered. At this point, there a couple recommended options for proceeding:

- One alternative is to narrow the scope of this EIS to **exploration** of the Marcellus Shale. At some point in the future, when sufficient information is collected, an additional EIS to support the **production/development** phase of the Marcellus Shale development can be drafted.

- Alternatively, the DSGEIS can attempt to combine exploration and production phases, but clearly define the data that must be obtained, and analyses that must be performed during exploration, to obtain sufficient information to support a production/development case. The DSGEIS could establish a process for conducting a site-specific environmental assessment for each production/development well site based on that data collected during the exploration phase.

2. NYS Regulations are Needed to Guide Marcellus Shale Exploration & Development

Recommendation No. 3: NYSDEC should update its regulations to include best technology and best management practices for oil and gas exploration and production in general, and more specifically for shale gas development. Oil and gas exploration and production should not be managed using out-of-date regulations, augmented by a patchwork of permit conditions and guidance memoranda. An updated regulatory framework provides: operators with clear, consistent rules to work from; NYSDEC staff with simplified instructions for implementation; a public process for input; and a more orderly and safe exploration and development process for NYS.

[5] Alaska Statute § 38.05.180.
[6] Alaska Statutes § 38.05.131 to .134.
[7] 20 Alaska Administrative Code § 25.517.

This DSGEIS proposes to build on the existing 1992 Generic Environmental Impact Statement (GEIS) for oil and gas drilling in NYS by providing additional information on the Marcellus Shale reservoir and high-volume hydraulic fracturing. This approach does not address the fact that, since 1992, numerous best technology and best management practice improvements have been made to basic elements of the E&P industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS's DSGEIS starts with an unstable foundation. Therefore, the first and most logical step in this analysis is to examine the basic elements of the 1992 GEIS and determine what new best technology and best practice improvements have been made since 1992, and update the foundation of the analysis. Then, and only then, can NYS build a well-supported incremental analysis that examines the impact of new techniques such as horizontal drilling and high-volume fracture treatments.

The 1992 GEIS is based on oil and gas regulations, most of which were adopted in 1972. 1972 vintage regulations are clearly inadequate to guide shale gas development in 2010 and beyond.

Since 1992, NYSDEC has found other gaps in NYS's regulatory structure and has developed numerous guidance documents in an attempt to bridge the regulatory gap.

Now in 2009, 17 years later (and 37 years after adoption of most of the existing regulations), NYSDEC is faced with antiquated regulations that do not address the decades of oil and gas best technology and best practice improvements. This situation is compounded by a patchwork of permit stipulations and guidance documents that attempt to regulate the oil and gas industry in NYS.

NYSDEC's 2009 DSGEIS further compounds the problem by adding another list of permit conditions (Appendix 10) for shale gas development, without taking the time to step back and develop an updated, comprehensive set of regulations to guide future oil and gas development in NYS.

It is recommended that this DSGEIS conclude that it is time for NYS to revise its regulations to include best technology and best management practices for oil and gas exploration and production in general, and develop regulations specific to the shale gas.

An updated regulatory framework provides: operators with clear, consistent rules to work from; NYSDEC staff with simplified instructions to implement; a public process for input; and a more orderly and safe exploration and development process for NYS.

The current patchwork of permit conditions and guidance documents do not provide for adequate public input because permit conditions can be revised subsequent to completion of the EIS, and guidance documents do not go through public review. NYS law requires public input in the regulatory development process, and any subsequent amendment.

Recommendation No. 4: Even if NYSDEC persists, without adequate data, in addressing both exploration and production in this SGEIS, the proposed supplementary permit conditions are incomplete and inconsistent with both some of the DSGEIS findings and best technology/practices for gas shale development. The "Proposed Supplementary Permit Conditions" should be renamed to serve as a "List of Regulatory Improvements Required to NYS's Regulations." This list should reflect the numerous recommendations herein and those substantive comments received by NYSDEC from others. The list should be used to revise the NYS regulatory framework, because the DSGEIS should appropriately serve as the basis for examining and improving NYSDEC's regulatory program for shale gas.

There is a significant disconnect in the DSGEIS between the assumptions, analysis and mitigation measures discussion in Chapter 7 and the final *Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing* (Appendix 10). NYSDEC proposes to use this revised set of permit conditions to regulate industry; thus, it is critical that the conditions reflect the best technology and best practices (mitigation), making the end-product a useable tool for the regulator, the applicant and the public.

As explained above, it is recommended that NYSDEC revise its regulations to include best technology and best management practices for oil and gas exploration and production in general, and shale gas development in particular. This approach provides the best, most comprehensive method of creating exploration and production stipulations, and is a substantial improvement over generating a patchwork of "proposed supplementary permit conditions" to bridge a known regulatory gap. This report, along with other reports submitted by NRDC and its co-signatories, provides specific recommendations for improving NYS's oil and gas exploration and production regulations.

As stated in the title, the purpose of this DSGEIS was to examine the "oil and gas and solution mining regulatory program," with a goal of more specifically identifying regulatory improvements to NYSDEC's regulatory program for shale gas, not to merely generate a list of permit conditions.

Therefore, it is recommended that the "Proposed Supplementary Permit Conditions" be renamed to serve as a "List of Regulatory Improvements Required to NYS's Regulations." This list should be updated and complete, reflecting the numerous recommendations herein and those comments received by NYSDEC from others. The refined list should serve as a basis for revising the NYS regulatory framework, which is the next logical step.

Recommendation No. 5: NYS's regulations need to be revised to address Marcellus Shale gas development, provide a clear, complete list of prohibited activities, and describe maximum allowable levels of activities and expected mitigation. When codified in regulations, NYSDEC staff, the applicant, and the public will fully understand the "bottom-line" requirements.

NYS's regulations need to provide a clear, complete list of prohibited activities, and describe maximum allowable levels of activities. The regulations also need to include a clear description of expected mitigation. This approach facilitates implementation and enables NYSDEC staff, the applicant, and the public to fully understand the "bottom-line" requirements.

In some cases, the DSGEIS proposes mitigation that is not carried through to the proposed permit conditions. In many cases, the DSGEIS describes limitations (e.g. maximum volume, duration, depth) to explain why NYSDEC believes the impact will be limited. Yet, often these limits are not translated into enforceable permit conditions. Without regulatory constraints, impacts from exploration and development activities will exceed those considered in the DSGEIS, and there may be undisclosed and unmitigated significant adverse environmental impacts.

While not an exhaustive list, the short list provided below demonstrates the disconnect between the limits and assumptions found in the text of the DSGEIS and the requirements listed in the *Proposed Supplementary Permit Conditions*. Other examples are identified elsewhere in this report. None of these limits found in the text of the DSGEIS are set by permit condition:

- diesel-based fracture fluid is not allowed;[8]

[8] DSGEIS, p. 7-41.

- site-specific analysis is required for high-volume hydraulic fracture at depths less than 2,000' TVD,[9] or if the distance between the target fracture zone and a fresh water supply is less than 1,000' TVD;[10]
- maximum hydraulic fracture size;[11]
- maximum three (3) days of flaring;[12]and,
- maximum of 250 days of operation for drilling engines, maximum of 20 days for hydraulic fracturing engines, and maximum of 30 days of flaring in a given year.[13]

In other areas of the DSGEIS, the stated limits conflict. For example, Section 6.5.2.2 "Sources of Air Emissions and Operational Scenarios" states that the worst case scenario for emissions produced from a single well pad is a drilling rig in operation while an adjacent well is being completed, another well is being routed to flare, and an onsite line heater is in use. This maximum case air pollution scenario doesn't take into account the possibility of a simultaneous drilling rig operation at the same well pad, which is discussed in Section 5.2.2: "*One operator has stated that on a well pad where six or more wells are needed, it is possible that two triple-style rigs may operate concurrently*." Therefore, the maximum air pollution case would be the operation of two concurrent drilling rigs, not just one, unless simultaneous operation of two drilling rigs on a single pad is prohibited. Because there are no limits on the number of concurrently operating air pollution sources in the proposed permit conditions, significant potential adverse impacts have not been determined, and required mitigation has not been identified.

The DSGEIS recommends in Chapter 7 that additional, more stringent permit conditions be added in some cases; however, these more stringent mitigation measures are not included in the *Proposed Supplementary Permit Conditions* (Appendix 10). For example, Section 7.1.3.4, p. 7-35, lists more stringent requirements in primary aquifers and unfiltered water supply areas, including: removal of fluids within 7 days of drilling and stimulation operations for each well; immediate fluid removal if operations are suspended; immediate fluid removal if the site is left unattended at any time; and removal of fluids within 7 days of completing drilling and stimulation operations at the last well on a pad. These more stringent requirements are not summarized in the proposed permit conditions for NYSDEC staff to select as an alternative to the 45-day timeframe allowed by proposed Permit Condition No. 16.

3. Drilling Mud Composition and Drilling Waste Disposal

Recommendation No. 6: NYS regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM content, NORM, and establish best practices for collection, treatment and disposal of drilling waste.

The 1992 GEIS allows drill cuttings to be buried onsite, and the DSGEIS is silent on the potential pollution impact from drilling muds. Current regulations incorrectly conclude that "drilling muds are not considered to be polluting fluids." 6 NYCRR § 554.1(c)(1). This error should be corrected.

Drilling muds are used to control the hydrostatic pressure in a wellbore. The most common weighting agent used is barite. U.S. Department of Energy studies show that barite contains mercury (1ppm-10ppm

[9] TVD= True Vertical Depth.
[10] DSGEIS, p. 7-49.
[11] DSGEIS, p. 6-56.
[12] DSGEIS, p. 6-63.
[13] DSGEIS, p. 6-72.

Hg, depending on its origin.)[14] Mercury concentrations can be reduced by using thermal methods, leaching with dilute acids, or selecting barite with naturally occurring lower concentration levels of mercury.[15]

The U.S. Department of Interior estimates that 0.8 metric tons of mercury is discharged into the Gulf of Mexico (GOM) annually (1839 lb Hg/yr) from mud disposed from drilling operations.[16] This equates to approximately 1.69 lbs of mercury per well, for wells drilled to a total depth of approximately 12,000'.

(1,091 wells/yr drilled in GOM)) (12,038 ft/well)*(140 lbs barite/ft)*(1x10^{-6} Hg/g barite)= 1,839 lb Hg/yr.*

(1,839 lb/Hg)/(1,091 wells) = 1.69 lbs of mercury per well.

Using an average wellbore length of 5,000' for a Marcellus Shale well, and a lower barite use rate of 100 lbs/ft to account for lower expected pressures, **the mercury content in the drilling mud is estimated at 0.5- 5.0 lbs of mercury per well,** depending on barite quality:

1ppm Hg in barite= (1 Marcellus well) (5,000 ft/well)*(100 lbs barite/ft)*(1x10^{-6} Hg/g barite) = 0.5 lb Hg/well*

10ppm Hg in barite= (1 Marcellus well) (5,000 ft/well)*(100 lbs barite/ft)*(10x10^{-6} Hg/g barite) = 5.0 lb Hg/well*

Drilling muds may also contain the heavy metal cadmium, leading the EPA to establish cadmium concentration limits in drilling muds for muds disposed offshore.[17]

The DSGEIS proposed permit conditions require a disposal plan pursuant to 6 NYCRR § 554.1(c)(1); however, the plan is not available for public review or input, so it is unclear what the plan will require.

The DSGEIS explains that NYS solid waste management regulations at 6 NYCRR Chapter IV, Subchapter B (Solid Waste) provide the authority by which the state (through the Division of Solid and Hazardous Materials) establishes standards and criteria for solid waste management operations, including landfills and land application. However, the DSGEIS is unclear on what NYSDEC has deemed to be the best management practice for handling drilling waste.

A recent U.S. Department of Energy review of NYS drilling waste disposal regulations concluded:

> *"The [NYS] **DEC has developed no regulations, policies, or guidelines** governing slurry injection, subsurface injection, or annular disposal of drilling wastes and reserve-pit wastes."*[18]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), nor has NYSDEC established limits on the heavy metal content of drilling mud additives.

Proposed Permit Condition No. 23[19] requires the use of a "closed loop tank system" instead of a reserve pit to manage drilling fluids and cuttings within a floodplain, but the DSGEIS not explain why a "closed

[14] http://www.fossil.energy.gov, "Mercury Removal from Barite for the Oil Industry."
[15] http://www.fossil.energy.gov, "Mercury Removal from Barite for the Oil Industry."
[16] http://www.gomr.mms.gov/homepg/regulate/environ/Hg%20discharge%20estimate.pdf.
[17] U.S. Environmental Protection Agency, Development Document for Effluent Limitation Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-93-003, 1993.
[18] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.
[19] DSGEIS, Appendix 10.

loop tank system" cannot be employed for all areas. Unless drilling mud and cuttings will be disposed of onsite, it is more efficient to use a closed loop tank system to collect this waste and route it to a treatment and disposal location, avoiding the impact of constructing a reserve pit and the potential for leakage into the environment.

There are numerous potential drilling mud disposal methods, but the DSGEIS is not clear on what method is determined to be best practice for NYS. New Mexico requires all fluids to be removed from the reserve pit and recycled or disposed of in accordance with state regulations.[20] New Mexico also requires the drill cuttings and reserve pit liners be sent to a disposal facility in accordance with state regulations, and the soil under the reserve pit to be tested for benzene, total BTEX[21], TPH[22], the GRO[23] and DRO[24] combined fraction, and chlorides.[25] If contamination is found, it must be excavated and remediated. If the soil is clean it can be backfilled. The City of Fort Worth, Texas, prohibits onsite burial of drilling muds and cuttings.[26] The reserve pits are temporary and all muds and cuttings must be removed and handled at an approved waste management facility.

NYSDEC's consultant, Alpha, concludes that although New Mexico and Texas have more stringent drilling cutting and mud disposal standards, allowing onsite burial of drilling cuttings may be acceptable for NYS because Pennsylvania allows that approach. Yet there is no analysis of the environmental consequences of onsite burial. And, there is no explanation as to why best practices in other states would not be considered for NYS. Since drilling muds contain heavy metals and other pollutants, and drill cuttings contain NORM in NYS, careful consideration of treatment and disposal options is needed. While NYSDEC provides some data on drill cutting NORM content, concluding the NORM content is too low to pose a concern. NYSDEC dataset is insufficient to demonstrate that the NORM content will be safe statewide, because shales are known to be very heterogeneous and the composition could vary substantially.

Proposed Permit Condition No. 40 requires only that the operator remove and handle drilling fluids pursuant to 6 NYCRR § 554.1(c)(1), but drill cuttings containing NORM and coated with drilling mud containing heavy metals and other chemicals can remain in the reserve pit after drilling mud is removed. Although the requirements of long-term burial are unclear, it appears that NYSDEC is proposing to leave the drill cuttings in the reserve pit at the site, without removal or any further treatment.[27]

The DSGEIS's muds and cuttings disposal plan raises a number of concerns. Foremost, 6 NYCRR § 554.1(c)(1) states that "drilling muds are not considered to be polluting fluids." Therefore, any waste management plan developed to dispose of drilling fluids, and approved by NYSDEC, would be based on the assumption that the drilling mud waste was non-toxic. Yet, drilling muds contain heavy metals and other pollutants. NYS's regulations need to be updated to reflect the actual composition of drilling muds and the potential environmental risk. NYS's regulations should provide specific instruction for the proper treatment and disposal of drilling muds and cuttings that contain heavy metals and NORM.

Second, 6 § NYCRR 554.1(c)(1) requires only submission of a waste management plan, but sets no standards for disposal. There is no instruction on what to do with the drill cuttings, or whether long-term

[20] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.17.
[21] BTEX= benzene, toluene, ethylbenzene, and xylene.
[22] THP= total petroleum hydrocarbons.
[23] GRO= gasoline range organics.
[24] DRO= diesel range organics.
[25] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.17.
[26] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.18.
[27] Except in a flood plain (where reserve pits are prohibited by Permit Condition No. 24).

onsite burial in the reserve pit is best practice. Alpha confirms that NYS's oil and gas regulations do not include instruction for how to dispose of drill cuttings containing NORM:

> *"The State's Oil and Gas Regulations do not specifically refer to discharge or storage of radioactive materials. Low-level, naturally occurring radioactive material (NORM) is present in many of the geological formations throughout much of New York. The development of natural gas wells into the Marcellus Shale can bring low-level NORM to the surface through produced fluids or cuttings. Subpart 380-1.2(e) of 6 NYCRR indicates that Part 380 for the Prevention and Control of Environmental Pollution by Radioactive Materials "does not apply to NORM or materials containing NORM unless processed and concentrated"; consequently, the disposal of drill cuttings from the Marcellus or other gas shales in New York would not be subject to the 6 NYCRR Part 380 regulations.* ***The drill cuttings generated, therefore, would not fall under WRR Section 18-33, and return of the drill cuttings to the ground at a drill pad site within the Watershed, also would not be prohibited"*** *[emphasis added].* [28]

NYSDEC's consultant, Alpha, concludes that:

> *"Deep well injection and landfill disposal are options in PA, but are not readily available options in NY, unless PA has the capacity to handle the increased volume from both NY and PA"*[29]

Therefore, it is not clear what the waste management plan is for drilling fluids and cuttings. Where will drilling waste be taken for treatment and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What type of treatment will be completed? What is the ultimate disposal location for the treatment by-products? If drill cuttings are not removed from the reserve pit, how will the operator ensure that there is no contamination left below the reserve pit liner before the reserve pit is covered and permanently closed?

Clearly, there is need for regulatory improvement. The DSGEIS should determine which drilling mud composition and disposal practices are "best practice" for the various locations and scenarios under evaluation in this DSGEIS. Based on the location and scenario, there may be reason to select one method over another. It is critical that NYSDEC carefully think through known best technology methods and best management practices, and then explain in the DSGEIS why it has selected the appropriate technology for the location and scenario under study.

At a minimum, the DSGEIS should examine the following practices and make a recommendation for the lowest environmental impact:

1. Waste minimization (drilling mud recycle and reuse when possible);
2. Use of drilling mud additives with lower environmental impact;
3. Beneficial reuse of uncontaminated drilling wastes;
4. Use of closed loop tank systems to transport waste, versus use of reserve pits;
5. Burial (e.g. landfills, or reserve pits);
6. Commercial treatment and disposal facilities; and/or
7. Underground injection.

A combination of waste minimization, selection of low impact additives, collecting waste in a closed-loop system, pumping that waste to a cuttings reinjection (CRI) unit, and disposing of the waste by deep well injection into a well-designed, properly constructed disposal well is usually the best management practice

---

[28] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.96.
[29] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p. 20.

in most applications. These methods: reduce waste; reduce toxicity; eliminate air pollution; and eliminate the need for surface disturbance from reserve pits and the potential for leaks, contamination, and future remediation. However, there may be unique locations and situations where this combination of practices is not appropriate and that must be thoroughly analyzed by NYSDEC in the DSGEIS.

4. Disposal of Drilling & Production Waste & Equipment Containing NORM

Recommendation No. 7: NYSDEC should adopt regulations to establish best practices for collection, treatment, and disposal of drilling and production wastes, as well as equipment containing NORM.

The DSGEIS acknowledges that drilling and production waste and equipment may contain Naturally Occurring Radioactive Material (NORM). NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and that this NORM may be present in drill cuttings, produced water and stimulation treatment waste.[30] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[31] Radiation pathways can include external gamma radiation, injection, inhalation of particulates, and radon gas.[32]

Produced Water Waste: Produced water is rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[33] NYSDEC reports it has insufficient data on NORM in produced water, but acknowledges that NORM is present and is known to be found in elevated levels. NYSDEC identifies the need for additional research and testing.[34] The DSGEIS proposed Permit Condition No. 47 (Appendix 10) requires produced water to be tested for NORM; yet, no treatment or disposal requirements are set based on the NORM testing outcome. It is unclear how the NORM test data will be used to establish the best waste management practice to safely dispose of produced water. Buried in the DSGEIS at p.7-50 there is one statement that indicates that NYSDEC will use a radioactivity scan in the decision to issue a Beneficial Use Determination (BUD), if "potential public exposure concern" is indicated, but the threshold for concern is not quantified. Nor is this requirement carried into the proposed permit conditions (Appendix 10) or the BUD application (Appendix 12).

Proposed Permit Condition No. 48 requires only that produced water be "disposed, recycled or reused" and transported by a waste transporter with a 6 NYCRR Part 364 permit. No pollutant thresholds, disposal limits or treatment requirements are set.

Recommendation No. 8: NYSDEC should adopt regulations prohibiting use of Marcellus Shale gas wastewater containing NORM for land or road spreading applications and establishing best practices for collection, treatment and disposal of drilling and production wastes and equipment containing NORM.

Appendix 12 of the DSGEIS states that produced water may be spread on roads if a BUD is issued by the NYSDEC Division of Solid and Hazardous Materials, under the Part 364 Transporter Program, but no thresholds or standards are established for NORM limits in the material. Other oil and gas producing

[30] DSGEIS, p. 4-36.
[31] DSGEIS, p. 6-129.
[32] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[33] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[34] DSGEIS, p. 5-31.

states, such as Texas, specifically prohibit road spreading of waste containing NORM.[35] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[36]

Since the Beneficial Use Determination does not require an operator to test for NORM,[37] it is unclear how the NORM testing at the well site will be integrated into the BUD process, and what level of NORM, if any will be allowed in fluids used for road spreading. The DSGEIS does not examine the cumulative impact of spreading small amounts of NORM, repeatedly over the same area. It is recommended that waste containing NORM be prohibited for use in land or road spreading.

The DSGEIS explores produced water disposal options (e.g. injection wells, treatment plants, and road spreading),[38] but does not land on a best practice method for produced water containing NORM.

Produced water containing NORM should **not** be used for road spreading. Produced water, containing NORM, should be returned to the subsurface formation from which it came, or should be handled at an approved waste treatment plant.

Furthermore, EPA identifies produced water pits (brine pits) as an outdated practice if produced water contains NORM. EPA reports that:

> *"Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM[39] in the water will concentrate in the bottom sludges or residual salts of the ponds. **Thus the pond sediments pose a potential radiological health risk**….produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is returned in the same or lower concentration to the formations from which it was derived"[40][emphasis added].*

Hydraulic Fluid Waste: The DSGEIS proposed Permit Condition No. 47 (Appendix 10) requires hydraulic fracture (frac) fluid waste to be tested for NORM; yet, no treatment or disposal requirements are set based on the NORM testing outcome. It is unclear how the NORM test data will be used to establish the best waste management practice to safely dispose of frac fluid.

Proposed Permit Condition No. 23 requires waste fluids to be handled in accordance with 6 NYCRR § 554.1(c)(1), yet this regulation does not specify the best practice for handling hydraulic fluid waste. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for an applicant to submit a waste management plan. The regulation states:

---

[35] Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.
[36] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.
[37] The example BUD application provided in Appendix 12 requires testing for calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil and grease, benzene, ethylbenzene, toluene and xylene, but not NORM.
[38] DSGEIS, p. 5-131.
[39] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.
[40] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

> *"Prior to the issuance of a well-drilling permit for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in* ***sufficient quantities*** *to be deleterious to the surrounding environment, the operator must submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids. For purposes of this subdivision, drilling muds are not considered to be polluting fluids. Before requesting a plan for disposal of such fluids, the department will take into consideration the known geology of the area, the sensitivity of the surrounding environment to the polluting fluids and the history of any other drilling operations in the area.* ***Depending on the method of disposal chosen by the applicant****, a permit for discharge and/or disposal may be required by the department in addition to the well-drilling permit. An applicant may also be required to submit an acceptable contingency plan, the use of which shall be required if the primary plan is unsafe or impracticable at the time of disposal" [emphasis added].*

Terms such as "sufficient quantities" deleterious to the environment are not quantified. The waste disposal method is selected by the applicant, with no instruction on the best waste management practice.

While recycle and reuse of frac fluid is discussed in the DSGEIS, there is no requirement to use this best practice in the proposed permit conditions. There is insufficient information in the DSGEIS to determine if the capacity exists to handle the high volumes of frac fluid that may be produced, especially fluid containing NORM, through either underground injection or surface treatment and disposal at an authorized facility.

Equipment Scale and Sludge: Equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[41] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[42] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[43] The most common form of scale is barium sulfate, which readily incorporates radium in its structure.

While the DSGEIS acknowledges the likelihood that NORM will build up in equipment scale and sludge,[44] the proposed permit conditions are silent on how equipment contaminated with NORM should be cleaned, handled, and disposed.

Because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[45] it is critical that states establish clear best practice requirements for handling E&P waste, especially NORM found in equipment scale and sludge. The DSGEIS cites other oil and gas states, such as Texas and Louisiana, as adopting stringent NORM regulations, including: occupational dose control, surveys, testing and monitoring, record keeping, signs and labeling, and treatment and disposal methods.[46] Yet, the DSGEIS does not recommend adopting these more stringent approaches taken by other states and is silent on any recommendation in the proposed permit conditions (Appendix 10).

---

[41] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.
[42] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[43] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment- an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.
[44] DSGEIS, p. 6-30.
[45] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.
[46] DSGEIS, p. 7-101.

The DSGEIS (Section 7.8.2)[47] describes NYS's existing radioactive waste regulations, noting that equipment contaminated with NORM may be subject to the NYS Department of Health licensing requirements under State Sanitary Code, Chapter 1, Part 16 (10 NYCRR 16) and Industrial Code Rule 38 (12 NYCRR 38). Yet it makes no conclusion as to whether E&P equipment contaminated with NORM will actually be subject to regulation or how the waste will be collected, treated, and disposed.

While NYS has some current regulations relating to radioactive material exposure and disposal, these rules are not specific to gas production equipment or methods. NYSDEC should adopt regulations to establish best practices for collection, treatment, and disposal of drilling and production wastes and equipment containing NORM.

NYSDEC should evaluate the following list of practices and determine which are best for the specific locations and scenarios examined in the DSGEIS:

1. NORM testing of all material produced from the gas well, all material used in well stimulation and equipment scale and sludge;
2. NORM testing of equipment scrap metal, and cleaning prior to smelting. Pollution control devices (e.g. filters and bubblers) should be installed in smelter stacks to reduce airborne radiation;
3. Reinjection of produced water back into aquifer of the gas reservoir from which it came;
4. Treatment and disposal by a licensed NORM disposal facility; or
5. Collection and transportation of waste for disposal in a salt dome.

5. Casing and Cementing Requirements

Recommendation No. 9: NYS casing and cementing regulations should be developed specific to Marcellus Shale gas reservoir development. They should address high angle well construction, ensuring that casing and cementing are structurally sound and provide an effective drinking water barrier, particularly when high-volume fracture treatments are performed.

Section 2.4.6 concludes that drinking water well contamination by oil and gas drilling activities, such as incidents reported in the 1980s in Chautauqua County, is mitigated by NYS's new casing and cementing practices and fresh water aquifer supplementary permit conditions.

While NYS's new casing and cementing practices are an improvement, these requirements are found in guidance instead of regulation, and therefore are subject to change by appointed officials without public review. The DSGEIS should conclude that NYS's new casing and cementing practices and fresh water aquifer supplementary permit conditions are mandatory minimum requirements for all wells drilled and fractured in low-permeability gas reservoirs in the state. Additionally, NYSDEC should take steps to codify these requirements in regulation.

Attachment C to the Comments on this DSGEIS prepared by AKRF, Inc. provides a September 16, 2009 report to NRDC documenting several recommendations for improving NYS's best practices for casing and cementing.[48] The September 16, 2009 report compares NYS's best practices for casing and cementing to those of other large and experienced oil and gas producing states (Texas, California, Alaska and Pennsylvania). Specific recommendations are included for: high angle well casing and cementing; cement

[47] DSGEIS, p. 7-103.

[48] New York State (NYS) Casing Regulation Recommendations, report prepared by Harvey Consulting, LLC., for the Natural Resources Defense Council (NRDC), September 16, 2009.

and casing quality standards and testing; operator certification; and when to set intermediate casing to protect ground water (especially in wells that undergo fracture treatments).

6. Flaring, Venting, and Fugitive Emissions

Recommendation No. 10: NYSDEC should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible.

Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[49] Initially the motive was to conserve hydrocarbon resources to maximize federal and state revenue and gas supply. More recently, focus on greenhouse gas (GHG) emission reduction has prompted additional innovation to further reduce flaring and venting.

Reducing flaring and venting to the lowest level technically achievable is widely considered best practice. The proposed permit conditions do not include this best practice. Proposed Permit Condition No. 2 merely requires notification to the county emergency management office when flaring occurs. NYSDEC should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible.

Drilling & Completions: Flares may be used during well drilling, completion and testing to safely combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except equipment malfunction.

During the drilling and completion phase of the first well on a well pad, a gas pipeline may not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply is found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to route it to. However, subsequent wells drilled on that same pad would be in a position to implement Reduced Emission Completion (REC), also called "green completion," which involves routing gas to a pipeline. Green completions require equipment to be brought to the well site to process wet gas from the well (during well completion activities) to ensure the gas meets pipeline specifications. The DSGEIS states that green completions are not currently required in NYS.[50] The DSGEIS estimates that without a gathering line in place, initial cleanup or testing could require flaring to last for three to 30 days.[51]

Gas Production: High pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[52] and gaseous by-product streams[53] that are uneconomical to conserve.[54] Venting or flaring may also occur during manual or

[49] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.
[50] DSGEIS, p. 6-52.
[51] DSGEIS, p. 5-125.
[52] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.
[53] For example: instrument vent gas; stabilizer overheads and process flash gas.
[54] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and removal of hydrates from pipelines.[55]

Best practices for flaring and venting during gas production should limit flaring and venting to the smallest amount needed for safety. Gas should be collected for sale, used as fuel, or reinjected for pressure maintenance, unless it is proven to be technically and economically unfeasible.

NYSDEC should adopt very clear regulations limiting flaring and venting during gas production operations. If gas collection, use, or sale is not possible, NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces hazardous air pollutants, volatile organic compound emissions, and GHG emissions.[56]

Several states (e.g. Alaska and California) require operators to keep accurate records of gas venting and flaring to ensure that the amount is limited to safety related needs. Some states and the federal government (in the Outer Continental Shelf) require operators to pay royalty and taxes on flared and vented gas not authorized for safety purposes. This encourages investment in gas collection and control devices to conserve natural gas. [57]

Best Practices for Flares: When flare use is necessary for safety, the following best practices should be instituted:

- Minimize the risk of flare pilot blowout by installing a reliable flare system;
- Ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams;
- Ensure use of a reliable ignition system;
- Minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and
- Maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates.

Best Practices for Venting and Fugitive Emissions: Best Practices for controlling venting and fugitive emissions include:

- Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks;
- Use of low bleed pneumatic instruments,[58] instrument air, electric or solar powered control devices;
- Use of dry centrifugal compressor seals;
- Use of smart automation plunger lifts for liquid unloading;
- Early installation of pipelines; and
- REC methods for gas well completions.

In most cases these best practices improve safety and collect marketable gas for sale. For example, RECs, “green completions,” provide an immediate revenue stream by routing gas that would otherwise be vented

[55] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[56] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[57] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

[58] Process controllers, chemical pumps, and glycol pumps often vent pressurized natural gas used for pneumatic actuation.

to a gas sale line. Industry has demonstrated that green completions are both best environmental practice and profitable. Green completion equipment has a short economic payout. A green completion requires the operator to bring in gas processing equipment to the well pad to clean up wet gas, improving it to gas pipeline quality. Typically, portable gas dehydration units, gas-liquid-sand separator traps, and additional tanks are required.[59] Most companies report a one-to-two-year payout for investment in their own green completion equipment, and substantial profit thereafter, depending on the gas flow rate.[60] It is also possible for smaller operators to rent green completion equipment. NYSDEC's consultant, ICF Incorporated LLC, found that equipment payouts may be as short as three months, and more than $65 million in profits was made on a national level in 2005 by companies conducting green completions.[61] Natural Gas STAR also provided technical advice to NYSDEC (Appendix 23) recommending green completions as a technically feasible economic method. Yet, the DSGEIS does not require green completions. The DSGEIS encourages participation in the Natural Gas STAR program,[62] but this program is voluntary and will not require operators to institute flaring and venting reductions. The best practice of green completions should be codified in NYS regulation.

7. Hydrogen Sulfide

Recommendation No. 11: NYSDEC should adopt regulations to require gas production operators to follow hydrogen sulfide detection and protection procedures for employees and the public during drilling **and** production operations.

The DSGEIS proposed Permit Condition No. 21 requires operators to conform to the American Petroleum Institute Recommended Practice 49 (API RP49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide. Hydrogen sulfide (H_2S) is a deadly gas. API RP49 is widely accepted as a guidance document. However, API RP49 does not address H_2S at gas production and processing facilities. API RP 55 addresses Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, including procedures to protect employees and the public. Both API RP49 and API RP55 should be added to NYS's regulatory requirements.

8. Seismic Data Collection

Recommendation No. 12: NYSDEC should establish regulatory requirements for seismic data collection that reduce impact to the environment and the public.

The DSGEIS addresses naturally occurring seismic events in Chapter 4, but is silent on the impacts of industrial seismic exploration used to locate subsurface gas reservoirs. Seismic waves created from a source on the surface travel through the earth and are reflected back to surface. Recording instruments called geophones collect data and transmit it to a seismic recording truck. The speed at which waves travel through the earth and are reflected allow geophysicists to map subsurface geology and identify potential gas reservoirs.

[59] EPA, Green Completion, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, Fact Sheet No. 703, 2004.
[60] Reduced Emissions Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop, Casper Wyoming, August 30, 2005.
[61] DSGEIS, Appendix 25.
[62] DSGEIS, p. 7-92.

Historically seismic exploration was most commonly conducted using dynamite placed in surface drilled boreholes to create small surface explosions that produced the requisite seismic waves.[63] Due to environmental and public concerns, dynamite use has decreased, and has commonly been replaced by large, heavy wheeled or tracked vehicles with Vibroseis units that propagate energy signals into the earth, or "thumper" trucks that pound the ground surface to create seismic vibrations by dropping a heavy weight raised by a hoist.

Seismic exploration data can be obtained to create two and three dimensional subsurface maps. This data is collected by running seismic equipment along a tightly gridded surface path, often requiring trees and brush to be cut to allow passage of the heavy equipment and crews. This method leaves surface scarring.

Due to competition among operators to locate gas resources, seismic surveys are usually collected and held proprietary, requiring each operator to collect its own data. This leads to multiple seismic surveys over the same surface terrain.

Best practices for seismic exploration should include:

- Prohibiting explosive use and requiring less destructive methods such as Vibroseis;
- Acquiring data during winter months, when ground is frozen and surface impacts are minimized;
- Encouraging operators to jointly conduct seismic surveys whenever possible to avoid repeat impacts;
- Limiting equipment and crew sizes to the smallest units possible to minimize surface damage and reduce the amount of tree and vegetation removal required;
- Maximizing data acquisition along existing roadways and cleared utility easements and routes; and
- Requiring restoration (planting trees and vegetation).

These best practices should be codified in NYS regulation.

9. Corrosion & Erosion Control

Recommendation No. 13: NYS regulations should require equipment to be designed to prevent corrosion and erosion, and require monitoring, repair, and replacement programs.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production are subject to internal corrosion by water, enhanced by the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in the gas. High velocity gas contaminated with water and sediment can erode internal pipes, fittings and valves.

The DGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require the best practice to design facilities resist to corrosion (e.g. material selection and coatings), or to monitor corrosion and repair and replace corroded equipment.[64] The DSGEIS concluded that NYS regulations need to be revised to require erosion monitoring, repair, and replacement programs as best practice.

[63] Sheriff, Robert E. and Lloyd P. Geldart, Exploration Seismology, Cambridge University Press, Cambridge., 1995.
[64] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

10. Spill Prevention

Recommendation No. 14: NYSDEC should adopt regulations to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities. NYSDEC should incorporate existing EPA oil spill prevention standards for oil and gas activities that require secondary containment for all fuel tanks 1,320 gallons and larger.

Section 5.2.1 and Appendix 7 include sample rig specifications showing 10,000-12,000-gallon fuel storage tanks used with the large rigs. Section 7.1.3.1 states the drilling rig fuel tanks are exempt from NYS's petroleum bulk storage regulations, and tank registration requirements at 6 NYCRR §§ 612-614, because they are temporary storage tanks (non-stationary).

It is not clear why temporary fuel tanks are exempt from NYS's spill prevention regulations, when all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5 and 10 year intervals. A <u>temporary</u> 1,100 gallon fuel tank poses a greater environmental risk than a <u>stationary</u> 1,100 gallon fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit. Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks, particularly when they may be installed in one location for a significant period of time, or alternative methods such as use of double walled or vaulted tanks should be considered, as explained further below.

NYSDEC recommends two mitigation measures be added to prevent fuel spills:

(1) "*encouragement*" to operators to set the tank 500' back from water bodies; and
(2) requirement to install secondary containment for tanks 10,000 gallons and larger placed within 500' of a waterbody.

NYSDEC references a draft NYSDEC Program Policy DER-17 for construction standards and a September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on how the secondary containment might be constructed. Appendix 10 proposed Permit Condition No. 13 relies on the outdated SPOTS memo and establishes weak setback standards "to the extent practical."

The DSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112 that apply to fuel tanks, including drilling tanks at 40 CFR § 112.7(c). EPA's regulations, which were revised in 2002, require sufficiently impervious secondary containment to prevent a discharge to the environment for tanks 1,320 gallons and larger. EPA allows an operator the opportunity to demonstrate under 40 CFR § 112.7(d) that it is impracticable to install secondary containment; however, EPA requires a formal written "impracticability determination." It also requires periodic integrity testing of the tank, leak testing of the valves and associated piping, a Part 109 contingency plan, and a written commitment of manpower, equipment, and materials to respond to a spill.

NYSDEC's recommended mitigation measures, and proposed Permit Condition No. 13, are insufficient to protect the environment from fuel spills.

- First, NYSDEC's proposed mitigation measure to "encourage" operators to set the tank 500' back from water bodies[65] is not enforceable.
- Second, NYSDEC's proposed mitigation measure to require secondary containment for tanks 10,000 gallons and larger placed within 500' of a waterbody provides less spill protection than EPA's standard.

[65] DGEIS, p. 7-27.

- Third, NYSDEC proposed mitigation measures reference an unenforceable draft NYSDEC Program Policy document (DER-17) for construction standards and an outdated September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on how a secondary containment could be constructed.

The DSGEIS estimates that as many as 16 vertical wells (9 horizontal) could be drilled from one central pad; each well would take approximately one month to drill; and approximately 10 wells could be completed and hooked up for production within a year.[66] Therefore large fuel tanks used for drilling could be located at a drill site for 1.5 years. This is sufficient time to install secondary containment for tanks.

When fuel tanks are used for shorter periods of time (e.g., a single well), double-walled or self-diking tanks could be used, avoiding the need to construct a large temporary containment are for only a short duration.

NYS regulations (either at 6 NYCRR §§ 612-614 or in 6 NYCRR §§ 550-559 pursuant to its authority under Environmental Conservation Law § 23-0305(8)(d)) should be amended to include drilling operations. Secondary containment standards, as well as inspection and integrity standards at 6 NYCRR §§ 613-614, should be applied to all fuel tanks of at least 1,100 gallons used to explore or develop the Marcellus Shale gas reservoir (and any other gas reservoir covered under the final EIS).

Other oil and gas producing states have allowed the use of vaulted, self-diked, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate it is infeasible to install a containment area meeting EPA's 110% of the largest tank volume requirement. NYSDEC could consider allowing these alternative tanks where secondary containment is proven to be infeasible.

Vaulted, self-diked, and double-walled portable tanks are equipped with catchments that hold fuel overflow or divert it into an integral secondary containment area. Industry standards for construction of vaulted, self-diked, and double-walled portable tanks include:

- Underwriters Laboratories' Steel Aboveground Tanks for Flammable and Combustible Liquids (UL 142);
- Appendix J of the American Petroleum Institute's (API) Welded Steel Tanks for Oil Storage (API 650); and,
- API's Specification for Shop Welded Tanks for Storage of Production Liquids (API Spec 12F).

Due to higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self–diked, and double-walled portable tanks to identify damage or corrosion using one of the following standards:

- Steel Tank Institute's (STI) Standard for the Inspection of Aboveground Storage Tanks, Third Edition (STI SP00l); or
- API's Tank Inspection, Repair, Alteration, and Reconstruction Standard (API 653).

Additionally, most oil-producing states also require that stationary and portable tanks be equipped with high–liquid-level alarms that sound and display in a manner immediately recognizable to personnel

[66] DSGEIS at pgs. 117, 120, and 311.

conducting a transfer; high–liquid-level automatic pump shutoff devices set to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of each tank.

11. Spill Response

> **Recommendation No. 15**: NYSDEC should adopt EPA SPCC requirements for drilling operations.

The DSGEIS at p. 7-33 recommends a spill response team and employee training for spill prevention. EPA's regulations at 40 CFR § 112 require a Spill Prevention Control and Countermeasures (SPCC) Plan for fuel storage volumes of 1,320 gallons or greater. EPA's requirements are much more comprehensive and stringent than the proposed mitigation measures suggested by NYSDEC. The DSGEIS should clearly state EPA's SPCC requirements, so that all operators are aware of them and comply. NYSDEC may also want to adopt more stringent oil spill prevention and response requirements in its regulations that exceed the federal EPA standard (many states have taken this approach).

12. Fuel Selection

> **Recommendation No. 16**: NYSDEC should require operators to use cleaner fuels than diesel (such as natural gas) or electric power whenever technically feasible.

Shale gas development provides a cleaner natural gas fuel source than liquid fuels. The DSGEIS is based on use of large quantities of diesel fuel to power onsite equipment, without consideration of alternative cleaner energy sources. While diesel engines are often used as the prime mover power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[67] EnCana, a gas producer, reports natural gas fired rigs reduce air pollution by 90% compared to diesel fired rigs.[68]

Some rigs have been converted to accept electric power. Power can also be supplied to the drilling rig by a natural gas powered reciprocating turbine that can generate electricity on site. If high-line power is available nearby the well site, rig power can be obtained directly from power lines, substantially reducing local air pollution impacts. Natural gas fired and electric powered rigs are commonly used in Alaska to reduce air pollution.

Power generated by natural gas fired engines or turbines can be used for hoisting equipment, fluid circulating equipment, lighting, rotary equipment, and to meet gas compression requirements.

An initial well on a well pad needs to be drilled with diesel to obtain a natural gas supply; subsequent wells can be drilled using natural gas or electric power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use.

---

[67] www.naturalgas.org.
[68] EnCana 2005 Annual Report.

13. Hydraulic Fracture Design and Monitoring

Recommendation No. 17: NYSDEC should revise its regulations to specify best technology and best practices that must be used to collect data, model, design, implement, and monitor a fracture treatment. The regulations should specify that all data collected by industry must be reported to NYSDEC and made available to the public. Best technology and best practices should include:

(a) Collecting additional geophysical and reservoir data to support a reservoir simulation model;

(b) Developing a high-quality Marcellus Shale 3D reservoir model(s) to safely design fracture treatments;

(c) Hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;

(d) Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of zone fractures;

(e) Collecting data, and carefully analyzing fracture treatment performance in the field on smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. at least 4,000' deep and 150' thick);

(f) Using experience gained on fracture testing in (e) to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals, *only* if technical data supports the safety of this technique);

(g) Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection; and

(h) Taking a conservative, step-wise approach to ensure there is technical data to support high-volume fracture treatments that protect the environment, before NYSDEC establishes a blanket permitting program allowing fracturing of the Marcellus Shale at all depths and all thickness intervals.

Experts agree that Marcellus Shale gas production can be maximized by drilling long horizontal wells to increase the drainage area, and conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments that are properly designed and sized to create fractured rock and improved permeability <u>within</u> the shale zone.

Fracture treatments that propagate fractures <u>outside</u> the shale zone (fracturing out-of-zone) reduce gas recovery and may risk pollutant transport beyond the Marcellus Shale formation. Pollutant transport and pollutant toxicity issues are addressed in Tom Myers' and Glenn Miller's reports to NRDC on the DSGEIS, and therefore are not addressed here. This recommendation centers on what type of data, analysis, tools, and methods a professional engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

The DSGEIS does not demonstrate that NYSDEC and/or operators have sufficient data on the NYS Marcellus Shale. Nor does it demonstrate that engineering tools are in place to ensure high-volume fractures can be constrained to the Marcellus Shale.

Buffer Zones Needed: Vertical fractures that extend above and below the shale zone will decrease gas recovery rates by allowing vertical migration into the overlying strata, or by allowing water influx from aquifers above or below the shale. NYS has a financial incentive to ensure fracture treatments are conducted correctly, because NYS will want to maximize its royalty share and tax revenue.

To avoid fracturing out-of-zone, engineers typically design fracture treatments with a buffer zone (an un-fractured zone at the top of the shale layer and at the base of the shale). Buffer zone size should increase with geologic and technical uncertainty. Buffer zone size may decrease as industry gains experience and data quality/quantity improves. The DSGEIS does not contain sufficient information to demonstrate that NYSDEC and/or operators proposing high-volume fracture treatments have developed engineering tools capable of computing a safe buffer zone.

Marcellus Experience Very Limited: Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.[69] Industry has limited experience exploiting the Marcellus Shale using horizontal wells and slickwater fracs. The first Appalachian Basin Marcellus Shale gas well stimulation using high-volume slickwater fracture treatments was only recently performed in Southwestern Pennsylvania in 2004.[70] Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the DSGEIS.

Even NYSDEC's consultants acknowledge that industry literature on and experience with the Marcellus Shale is so limited that most of their analysis was based on development of other shale gas reservoirs, such as the Barnett and Fayetteville. NYSDEC's consultant, ICF, states that:

> "***Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale***. *While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example,* ***technical studies have yet to be published*** *that quantify actual drilling operations in Marcellus Shale.* ***For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations*** *[emphasis added].*[71]

Lack of Marcellus Shale experience increases the risk of fracturing out-of-zone, unless a conservative, step-wise approach is taken to better understand the Marcellus Shale before large scale development occurs in NYS.

NYS Marcellus Data Set Improvement Needed: Site-specific data, unique to the Marcellus Shale in NYS, must be collected to: better understand the reservoir heterogeneities; develop sophisticated three dimensional (3D) reservoir models to more accurately design fracture treatments; and examine actual fracture performance in the field. Reservoir simulation models are critical engineering design tools. The DSGEIS provides no indication that a model exists for the NYS Marcellus Shale.

Engineers use 3D models to predict fracture height, length, and orientation prior to actually performing the job at the well. The goal is to design a stimulation treatment that optimizes fracture networking and maximizes gas production, while confining fracture growth to within the gas shale target formation.[72]

[69] Cipolla, C.L., Lolon, E.P., and Mayerhofer, M.J., Reservoir Modeling and Production Evaluation in Shale-Gas Reservoirs, International Petroleum Technology Conference, Paper 13185, December 2009.
[70] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.
[71] NYS DSGEIS, ICF Task 2 Report, p.1.
[72] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, Presented at The Ground Water Protection Council 2008 Annual Forum Cincinnati, Ohio, September 21-24, 2008.

Engineers examine various parameters (e.g., volume, pressure, treatment placement) to optimize a fracture treatment. Without a high-quality 3D reservoir simulation model to design a fracture treatment, operators cannot demonstrate to NYSDEC that the fracture is predicted to stay in zone.

Typically an operator would start by collecting core analysis, well logs, and other subsurface data in the area it is interested in developing, to populate a site-specific 3D reservoir model. To collect this data, additional exploration and appraisal wells must be drilled (see recommendation No. 2). The limited amount of special core analysis and core data on the Marcellus Shale, as well as overlying intervals, is described in Chapter 4 of the DSGEIS, showing a need for additional data.

Test in Deepest, Thickest Zones First: NYSDEC is proposing to allow high-volume fracture treatments, without requiring the standard of care a petroleum engineer would typically use to collect data, and model, design, and monitor fracture treatments. NYSDEC should require that additional data be collected to support a model, and initially it should only allow a few, small fracture treatments that are conducted with intensive monitoring to verify that they are designed and implemented to stay within the Marcellus Shale. This data gathering and testing should be conducted in the deepest portions of the Marcellus Shale (below 4,000’) and in the thickest section of the shale (over 150’) to ensure there are adequate buffer zones to protect the environment during the data gathering and testing process. Operators should start with smaller fracture treatment sizes, collecting field data to better understand fracture performance, and use field data to calibrate that performance in the 3D model.

Over time, with careful analysis and a conservative, step-wise approach, larger fracture treatments can be tested and carefully monitored. Over time it may be possible to safely use the treatments on thinner reservoirs and shallower reservoirs, but certainly not as a first step. High-volume fracture treatments should not be conducted until there is a sophisticated data set, model, and monitoring program to verify pre-fracture and post-fracture reservoir properties.

Regulations Needed: While NYSDEC’s consultant, ICF[73], documents a number of the engineering methods that can be used to model, monitor, and improve fracture treatments, NYSDEC does not require any of these methods in its existing regulations. Absent a regulatory requirement, there is no assurance these methods will be used.

Best practice for hydraulic fracture planning includes a detailed understanding of the in-situ conditions present in the reservoir (e.g., shale thickness, reservoir pressure, rock fracture characteristics, and special core analysis). In highly heterogeneous reservoirs, reservoir simulation is often coupled with stochastic methods (e.g. Monte Carlo analysis and geostatistical techniques) to improve the quality of the 3D reservoir model.[74]

Data collected on previous fracture treatments in the Marcellus Shale and drilling data will be useful to refine the fracture modeling. Actual fracture treatments must be carefully monitored and implemented to ensure fractures stay within zone. Data collected during each fracture treatment should be used to calibrate the 3D reservoir model to improve future fracture treatment design.

Peer-reviewed articles and technical data on Marcellus Shale vertical fracture growth characteristics are sparse. While fracture growth models exist at an industry level, and have been tuned for fracture treatments in the Barnett Shales and other gas reservoirs, considerable technical work is still needed to develop fracture growth models for NYS Marcellus Shale development.

[73] ICF International, Technical Assistance to NYS on DSGEIS, August 2009.

[74] Schepers, K.C., Gonzalez, R.J., Koperna, G.J., and Oudinot, A.Y., Reservoir Modeling in Support of Shale Gas Exploration, Society of Petroleum Engineers, June 2009.

A literature review was completed by the author in search of a Marcellus Shale 3D reservoir model for NYS; none was found in the petroleum engineering published literature. It is not clear if the lack of a Marcellus Shale reservoir model for NYS indicates that one does not exist, or whether industry is holding models proprietary. Yet in other shale gas developments (e.g., Barnett and Fayetteville) there is extensive industry literature on: available reservoir simulation model; completion and fracture design; and performance assessment to compare predicted fracture growth with that achieved in the field. Lack of industry literature is usually a strong indication that additional data gathering and technology development is needed.

The data void for NYS's Marcellus Shale technical literature reinforces the need for NYSDEC to use a conservative, step-wise approach, rather than launching into a massive drilling and fracturing campaign without the data or tools in place to do a safe and effective job.

NYSDEC should require additional information be collected by industry to better understand the geological and geophysical properties of the Marcellus Shale zone and the overlying strata between the Marcellus and drinking water aquifers.

NYSDEC should require 3D reservoir simulation models be developed to accurately predict hydraulic fracture treatment performance, and to ensure the jobs are well engineered and designed with adequate safety factors to avoid fracturing out-of-zone.

The DSGEIS must assure the public that fractures can be contained to the Marcellus Shale zone. The DSGEIS does not provide data sufficient to meet this standard. The DSGEIS does not document the existence of 3D reservoir simulation models for NYS's Marcellus Shale, nor does NYSDEC require engineers to design fracture treatments using 3D models.

While Marcellus Shale development in Pennsylvania precedes development in NYS, data collected from the Pennsylvania wells is not applicable to the NYS Marcellus Shale because the depth of burial, thickness, organic content, permeability, and other reservoir properties in NYS differ. Industry experts warn that site-specific data is critical:

> *"By their nature, **shales are extremely variable** and **regional differences in structure, mineralogy and other characteristics should always be considered in treatment design**…The wide geographic range [of the Marcellus Shale] has led to numerous different completion schemes being utilized as with the geographic variation comes geologic variability within the formation itself. A primary topic of [industry] discussion has been determining the optimal size and type of stimulation treatment for a given area"* [75] *[emphasis added].*

The Marcellus Shale thickness drops off substantially in western NYS to less than 75' for roughly one-third of the total development.[76] Fracturing thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken to design and implement the fracture treatment. Hydraulic fracture treatments in NYS must be carefully tailored to the geophysical properties of the Marcellus Shale in NYS, taking into account shale thickness, local stress conditions, compressibility, and rigidity.

NYSDEC's consultants point out that a gas operator has no incentive to fracture out of the Marcellus Shale zone because doing so could result in a loss of gas reserves or increase produced water volumes.

---

[75] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

[76] DSGEIS, Figure 4.9.

Yet NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it could be possible to inadvertently fracture out of zone. As a result, ICF examined the potential for fracture fluids to propagate vertically and contaminate an overlying drinking water aquifer.

Proposed permit conditions (Appendix 10) require a Pre-Frac Checklist and Certification (Appendix 20). The conditions require and the checklists verify a number of important best practices for fracture treatments; however, additional NYS regulatory requirements should be considered to further refine the mitigation and codify these practices.

NYSDEC should require operators to complete hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone and to collect data to further refine a hydraulic fracture model for the Marcellus Shale. These requirements should be added to NYS's regulations.

NYSDEC could either develop a Marcellus Shale fracture model that could be used as a standard for all operators, or it could require operators to collaboratively fund the development of a model. In either case, model(s) should be developed by a fracture expert and be peer-reviewed prior to use. Model(s) should be maintained, calibrated using field data, and continuously improved to ensure fracture prediction matches field implementation as closely as possible.

Technology is available to assess actual fracture growth including: minifracs,[77] microseismic fracture mapping,[78] tilt surveys, well logging (e.g., tracer and temperature surveys[79]), etc.[80] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[81] This data can be obtained in the Marcellus Shale in a few different areas of NYS to further refine the hydraulic fracture model. Minifractures are particularly helpful in estimating fracture dimensions, fracture efficiency, closure pressure, and leakoff prior to implementing a high-volume, full-scale treatment. NYSDEC should require operators to conduct minifractures to better understand site-specific reservoir characteristics prior to conducting a high-volume fracture treatment.

The fracture treatment should be carefully monitored, and shut down if pressure data indicates casing leaks. The American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, and immediate shutdown of the fracture treatment if abnormal pressures indicate a casing leak.[82]

---

[77] Minifracs are small fracture treatments conducted in the well to better understand fracture conductivity and flow geometry prior to implementing a large fracture treatment. Minifracs are typically used to optimize the fracture design and calibrate the fracture model. These tests involve periods of intermittent injection followed by intervals of shut-in and/or flowback. Pressure and rate are measured throughout a minifrac and recorded for subsequent analyses.

[78] Microseismic monitoring is a method that measures the seismic wave generated during a fracture treatment to map the fracture extent, and it can be used to make "real-time" changes in the fracture design and implementation program.

[79] After the fracture treatment is completed, an operator can run a temperature log in the well to measure the variation in reservoir temperature resulting from the treatment. The reservoir temperature is hotter than the fracture fluid and proppant. Cooler temperatures will be measured where frac fluid and proppant are placed. Temperature logs will provide insight into fracture location and growth outside the casing.

[80] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

[81] Schlumberger, Microseismic Hydraulic Fracture Monitoring, http://www.slb.com/content/services/stimulation/stimmap.asp.

[82] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

Recommendation No. 18: NYSDEC needs to technically justify the proposed minimum 1,000' vertical offset with actual field data, 3D reservoir simulation modeling and a peer-reviewed hydrological assessment to ensure drinking water sources are protected.

Vertical Offsets Useful If Sized Correctly: The use of vertical offset limits to separate hydrocarbon recovery operations from drinking water aquifers is a good approach. However, the size of the vertical offset must be technically supported to ensure it is large enough to protect the drinking water aquifer.

ICF recommended additional well-specific technical analysis for high-volume hydraulic fracture treatments conducted at depths less than 2,000' TVD, or if the distance between the target fracture zone and a fresh water supply is less than 1,000' TVD.[83] ICF assumes that vertical fracture conducted in a horizontal section of a Marcellus Shale will not propagate more than 1,000' and intersect a drinking water aquifer above. Yet ICF does not provide NYS specific 3D reservoir simulation modeling or field evidence (e.g., pressure data, microseismic fracture mapping, tilt surveys, history matching simulation, or tracer testing) to support its recommendation. ICF does not substantiate how it can guarantee that an operator will not implement a fracture out-of-zone or propagate above the Marcellus. ICF argues that the 1,000' vertical buffer is a safe distance between the top of the Marcellus and a drinking water zone, but site-specific data is needed to support this hypothesis.

ICF argues that even if a fracture does propagate out-of-zone above the Marcellus, the fracture fluid will not migrate into the drinking water zone above, if at least 1,000' vertical offset is maintained. ICF also argues that absent a direct fracture connection from the Marcellus to the drinking water aquifer, it would not be possible for contaminants to flow from the Marcellus to the overlying aquifer. Yet Tom Myers' report for NRDC identifies a number of problems with ICF's hydrological analysis and assumptions. Myers, a professional hydrologist, shows that it is possible for fracture fluids to naturally migrate toward the drinking water aquifer over time. Myers recommends additional data collection and analysis on this point.

Moreover, while ICF recommends at least a 1,000' vertical standoff to protect drinking water sources, there is no equivalent regulatory limit requiring this vertical buffer in NYSDEC's proposed permit conditions (Appendix 10). If a vertical buffer is needed for drinking water protection, that limit should be clearly stated in NYS regulations. The 1,000' vertical buffer zone must be technically justified or a larger vertical offset should be adopted to ensure drinking water standards are protected.

Proper design and monitoring of hydraulic fractures is not only best practice from an environmental and health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. The most logical way forward is to limit development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers until an accurate, field-calibrated 3D reservoir simulation model is developed for designing fracture treatments in NYS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4,000') will maximize data collection on the Marcellus and all overlying intervals between the Marcellus and the drinking water aquifers. This will allow core samples, well logs, and pressure transient data to be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers.

[83] DSGEIS, p. 7-49.

Smaller fracture treatments should be tested, initially, increasing in size over time only when data is collected to support the conclusion that large fracture treatments can remain in zone.

As data is collected, and 3D reservoir simulations models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals. However, there is insufficient technical data in the DSGEIS to support development of shallow, thin sections of the Marcellus at this time. Neither NYSDEC nor its consultant team has demonstrated that high-volume hydraulic fracturing can be safely conducted in thin sections of the Marcellus Shale at depths as shallow as 2,000' deep.

14. Hydraulic Fracture Treatment Additive Limitations

> **Recommendation No. 19**: NYS regulations should identify the type, volume, and concentrations of fracture treatment additives that are protective of human health and the environment. NYS regulations should develop a list of prohibited additives and require the use of non-toxic materials to the extent possible.

DGEIS Section 5.3[84] states that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reports it has some compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provide lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 describes the potential health impacts of categories of chemicals. Yet the DSGEIS does not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not.

While Section 5.4.3.1 lists a number of potential adverse human health and environmental impacts, the mitigation measures proposed in Chapter 7 do not set limits on chemical use (volume or concentration) that are protective of human health and the environment. Chemical use should be limited to non-toxic chemicals that do not pollute the air or water.

Section 9.3.1[85] briefly describes the possibility of using environmentally friendly chemicals, but rules this option out due to the lack of "green chemical" metrics in the US.

Appendix 10, Proposed Permit Condition No. 32, limits the use of fracturing products to those identified in the well permit application, but it does not specify what chemicals are actually acceptable to include in a well permit application. This proposed permit condition appears to allow any fracturing product proposed by industry in a well permit application.

This proposed permit condition also states that NYSDEC "may require a site-specific environmental assessment and SEQRA determination" prior to approving fracturing treatment chemicals that were not "previously reviewed." It is not clear what is meant by "previously reviewed." Does this mean fracture treatment chemicals "previously reviewed" in the DSGEIS? If this is the meaning, it raises serious concerns because, while the DSGEIS lists a number of fracturing products in Chapter 5, it does not make a toxicological decision about which chemicals are acceptable. In its current form, NYSDEC cannot rely on Chapter 5 to guide NYSDEC staff as to which fracturing treatment chemicals should be used. Chapter 5 is merely a "laundry list" of chemicals currently used without an adequate review of the potential impacts on health or the environment.

[84] DSGEIS, p. 5-34.
[85] DSGEIS, p. 9-10.

There are several models in place that NYSDEC could use to develop regulations and standards for fracture fluid composition. For example, many government entities have adopted the Olso-Paris Convention (OSPAR) PLONOR list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk to the marine environment) for screening chemical use in drilling and stimulation treatments. Other government entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive affects.

Best environmental practices can be implemented by developing a list of environmentally friendly chemicals that operators must comply with, as well as a list of chemicals that are prohibited.

15. Hydraulic Fracture Fluid Flowback Surface Impoundments

Recommendation No. 20: NYS regulations should require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

The DSGEIS does not present a consistent or clear recommendation on whether fracture fluid flowback impoundments are environmentally acceptable or allowed. The DSGEIS also leaves many other unanswered questions about what the expectations are for operators. Is the operator required to flow back fracture fluid to a tank? Are toxic chemicals allowed in impoundments? Is the operator required to stop using impoundments and flow to tanks? Is an operator required to complete site-specific modeling to better understand hazardous air pollutant impact from flowback impoundments? Or is an operator just required to build a larger fence to keep the public and wildlife away from the hazardous waste?

Best technology for fracture flowback treatment is to eliminate the use of surface impoundments altogether. The use of temporary surface impoundments results in surface disturbance. It also has the potential for leakage to occur through or around the liner, impacting ground water and creating substantial amounts of hazardous air pollution. The BLM recommends the use of closed loop tank systems whenever possible.[86] Fort Worth, Texas, prohibits frac fluid placement in an open pit.[87]

Fracture treatment flowback to metal tanks is an efficient collection method because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. Flowing fracture treatment fluid into a temporary reserve pit for later collection and disposal is inefficient, and creates the possibility of fracture fluids contaminating ground water (e.g. a leaking reserve pit liner).

Of serious concern is the amount of hazardous air pollution predicted for these surface impoundments. Section 6.5.1.8 of the DSGEIS, "Potential Emission of Fracturing Water Additives from Surface Impoundments," concludes that:

> *"Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of **32.5 tons** (i.e.,"**major" quantity of HAP**) is theoretically possible at a central impoundment"[88] [emphasis added].*

[86] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
[87] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p. 9.
[88] DSGEIS, p. 6-56.

Section 6.5.2.2, "Sources of Air Emissions and Operational Scenarios," states: "The Department has performed an assessment of a set of representative chemicals in the additives." But, NYSDEC has not set any limits in the DSGEIS on the type of chemicals that can be used in fracture treatment; therefore, there is no assurance that NYSDEC's subsequent air impact analysis at 6.5.2.3 is a worst case scenario or even representative of the emissions that will actually occur in the field (see analysis at pp. 6-75 though 6-76).

While it is unclear if NYSDEC's estimate of 32.5 tons of Hazardous Air Pollutants (HAPs) is even a worst case assessment, this is an unacceptably large amount of HAPs. NYSDEC's HAPs finding, alone, should result in a mitigation measure that prohibits operators from using fracture fluid flowback impoundments, and requires operators to collect fracture fluid flowback into closed treatment systems and/or closed tanks for transport to a treatment system.

This mitigation measure should be codified in NYS regulations.

The DSGEIS acknowledges the human health and environmental exposure risks, and proposes several different solutions, but does not identify a solution that meets a best practices standard. In fact, its recommendations are inconsistent.

For example:

Section 7.5.3.2, "Centralized Flowback Water Surface Impoundments" states:

> *"The **EAF Addendum will require the operator to identify all proposed fracturing additives**. **Site specific review of potential HAP emissions will be based on these proposed additives** (i.e., components and concentrations) and assessing air quality impacts of these compounds might be necessary, **unless the same additive mix has been previously analyzed** for a similar centralized impoundment. The EAF Addendum will also require the operator to identify proposed control measures for preventing public exposure to HAPs in excess of guidance thresholds. **These could consist of eliminating specific compounds such as methanol, heavy naptha and benzene**; **limiting the duration and use of the impoundment; covering the impoundment or placing physical barriers**"[89] [emphasis added].*

Section 7.5.3, "Summary of Air Quality Impacts Mitigation" proposes different mitigation:

> ***"If flowback impoundments are to be used, it will be necessary to exclude "solvent" and certain surfactants (containing benzene and xylene) from the current list of additives proposed by industry for use in fracturing operations**. Furthermore, for the remaining chemicals, it is necessary to take steps to **preclude public exposure to certain pollutant impacts by either eliminating their use or fencing in the impoundments**. Specifically, for the smaller on-site impoundments, limiting public access to beyond approximately 150m from the impoundment would be one means of eliminating potential adverse impacts. On the other hand, for the larger centralized impoundment, **public exposure to potential adverse impacts can be eliminated by erecting a fence at a rather large distance of approximately 1000m**, or at a smaller distance if certain chemicals listed in Table 6.21, are eliminated. It is also determined that these larger off-site impoundments have the potential to qualify as a major source of Hazardous Air Pollutants (HAPs) due to certain chemicals. Thus, a case specific review might be required for these larger impoundments"[90] [emphasis added].*

[89] DSGEIS, p. 7-90.
[90] DSGEIS, p. 7-89.

On p. 7-90, the DSGEIS provides yet a different conclusion:

> *"However, as discussed elsewhere in this Supplement,* ***uncertainties relative to potential flowback water volume and composition have led the Department to propose that flowback water not be directed to an on-site reserve pit but instead be held on the well pad in tanks prior to shipment to a disposal, treatment or re-use location****"[91] [emphasis added].*

Section 7.1.7.4, "Use of Tanks Instead of Impoundments for Centralized Flowback Water Storage" then says:

> *"Above ground storage tanks have some advantages over surface impoundments. The Department's experience is that landfill owners prefer above ground storage tanks over surface impoundments for storage of landfill leachate.* ***Tanks, while initially are more expensive, experience fewer operational issues associated with liner system leakage****.* ***In addition, tanks can be easily covered to control odors and air emissions from the liquids being stored.*** *Precipitation loading in a surface impoundment with a large surface area can, over time, increase the volumes of liquid needing treatment. Lastly, above ground tanks also can be dismantled and reused. The provisions of Section 360-6.3 address the minimum regulatory requirements applicable to above ground storage tanks which would be equally* ***applicable for adequate flowback water containment as well****"[92] [emphasis added].*

Section 7.1.3.4[93] proposes fracture treatment flow back be routed to metal tanks, rather than reserve pits.

NYSDEC's consultant reports that the most common, current practice observed at Pennsylvania drilling sites is for the frac flowback to be contained in a closed system that captures the water in steel frac tanks.[94]

The DSGEIS is unclear on what an operator will be required to do in terms of fracture fluid flowback. NYSDEC's proposed application and mitigation system is cumbersome, time consuming, and labor intensive. It is not clear that NYSDEC has the staff needed to oversee permitting and enforce the new requirements proposed in this DSGEIS. A simplified, best practice approach of prohibiting, via regulations, surface impoundments for fracture fluid flowback is more cost effective and protective of human health and the environment. There could be a provision in the regulations for an operator to make a showing that it is technically infeasible to operate without fracture fluid flowback impoundments, and in these limited cases a more detailed assessment could be made at a site-specific level to determine if an impoundment is best technology for that situation.

Please note that this recommendation does not include freshwater surface impoundments where water may be collected prior to adding fracture treatment chemicals. Operators developing the Marcellus Shale gas reservoir in Pennsylvania have found that:

> *"The preferred method for delivery of water to the wellhead is to pump water directly from a withdrawal point on a surface water source through pipelines to an impoundment or tank battery near the well completion location. In order to pump efficiently, the surface water withdrawal point should be located within one mile of the storage. Direct pumping is the preferred method because it substantially reduces the risks and costs associated with bulk hauling by truck… Bulk*

[91] DSGEIS, p. 7-90.
[92] DSGEIS, p. 7-55.
[93] DSGEIS, p. 7-34 and 7-35.
[94] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.19.

hauling over public roadways is not the preferred method to supply source water for fracing as it can cause roadway damage, increased traffic congestion, air and noise pollution and increased safety risk."[95]

In areas where bulk hauling over public roadways is not a preferable environmental alternative, freshwater surface impoundments may be a reasonable option, because freshwater does not pose a risk of water or air pollution. However, NYSDEC should ensure there are adequate regulations for surface disturbance reclamation.

Recommendation No. 21: The DSGEIS should disclose how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario.

The DSGEIS appears to report water use and waste volumes based on a single initial fracture treatment; this approach does not consider the fact that most shale gas wells require multiple fractures treatments. The DSGEIS should disclose how many times a well may be fracture treated over its life, and provide a worst-case scenario for water use and waste disposal requirements based on this scenario. It may be possible that repeat fracture treatments would not only dramatically increase water needs and disposal volumes, but also result in long-term use of impoundments pits. NYSDEC is not proposing to design impoundments for long–term use.

16. Chemical Tank Containment

Recommendation No. 22: NYSDEC should adopt regulations requiring secondary containment for chemicals stored on the well pad or, alternatively, the use of double-wall tanks.

Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. Best practice for permanent chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[96] NYSDEC's consultant, Alpha, agrees on this point, yet Alpha's recommendation does not materialize into a permit condition. Alpha's report states:

"It is recommended that regardless of exemption or regulatory status, the temporary on site storage of hydrofracing additive chemicals (and petroleum) comply with accepted best management practices (BMPs) for handling and spill containment. These practices may include, as appropriate to the specific containers, monitoring and recording inventories; manual inspections; berms or dikes, secondary containment; monitored transfers, storm water runoff controls, mechanical shut-off devices, setbacks, physical barriers, and materials for rapid spill cleanup and recovery."[97]

Alpha specifically recommended that chemical tanks be placed in lined containment areas, sufficient to contain 110% of the single largest chemical container, and that the tanks be set back from a perennial or intermittent stream, private or public well, wetland, storm drain, lake, or pond. These important best

[95] Gaudlip, A.W., Paugh, L.O., and Hayes, T.D., Marcellus Shale Water Management Challenges in Pennsylvania, SPE Paper 119898, November 2008.
[96] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
[97] Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.36-37.

practice recommendations were not included, but should be, in the DSGEIS; they should also be codified in NYS regulations. Alternatively, double-wall tanks may provide another protective alternative.

17. Reserve Pit & Impoundment Liner Quality

> **Recommendation No. 23**: NYSDEC should adopt regulations requiring closed-loop tank systems as a best practice instead of reserve pits and impoundments, unless the operator demonstrates that it is not technically feasible.

The BLM recommends the use of closed loop tank systems as a best practice instead of reserve pits and impoundments, whenever technically feasible.[98] Texas requires closed looped mud systems with steel tanks.[99] It is much more efficient (from an energy standpoint) to collect waste in the container that will be used to transport it offsite to a waste disposal facility than it is to create an intermediate storage pit. The use of temporary reserve pits and impoundments results in surface disturbance. It also has the potential for leakage to occur through the liner, impacting groundwater. NYS regulations should require use of closed-loop tank systems, unless an operator can demonstrate is not technically feasible to operate without a reserve pit or impoundment. NYSDEC reports that some operators use closed loop tank systems to capture muds, cuttings, and flow back fluids (Section 5.2.3).[100] This is a best practice that should be required for all operations.

> **Recommendation No. 24**: If reserve pits and impoundments are demonstrated to be environmentally preferable, NYSDEC should adopt regulations that require impermeable, chemical resistant liner material, and limit the type of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements.

If there are cases where reserve pits and impoundments are necessary, liner quality should be specified. NYS regulations should specify under what circumstances closed-looped tank systems are not technically feasible, and specify that only under these limited circumstances, if any, should reserve pits and impoundments be used. In cases where reserve pits and impoundments are necessary, regulations should require the use of impermeable, chemical resistant liner material. Proposed Permit Condition No. 12 establishes liner thickness and seam specifications, but does not specify liner quality.

The DSGEIS notes that some drilling and stimulation chemicals can react with and damage reserve pit liner materials.[101] The DGEIS reiterates the importance of installing impermeable liner material and ensuring the liner is maintained, repaired, and replaced.[102] Yet, the proposed supplementary permit conditions do not include a requirement to install impermeable, chemical resistant liner material.

The DSGEIS does not limit the types of chemicals that can be introduced into the reserve pits or impoundments. For example, used oils, paints, pipe dope, as well as toxic, corrosive, or bioaccumulating chemicals, should be prohibited.

---

98 Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.
99 Alpha Environmental Consultants, Inc., Report for NYS on DSGEIS, September 2009, p.8 states Fort Worth, Texas, requires closed tanks.
100 DSGEIS, p. 5-29
101 DSGEIS, p.7-29
102 DSGEIS, p.7-29 and p. 7-30

NYSDEC should list the type of chemical additives that are allowed to be temporarily stored in a reserve pit, and identify liner material specifications that will ensure the liner material is both impermeable and chemically resistant to those materials.

- Proposed Permit Condition No. 16 requires fluids to be removed from the reserve pit, and the pit to be reclaimed within 45 days of drilling or stimulations operations, but does not specify what materials may actually be left in the reserve pit for long-term burial and storage. For example, Section 7.1.9 indicates that cuttings drilled with oil based muds cannot be stored in reserve pits, but it does not explain which type of muds and cuttings would be allowed for long-term disposal (e.g,. are all water based and synthetic muds and additives allowed?).
- What type of testing will be required to ensure the material left in the reserve pit will not be harmful to the environment? For example, barite, a common ingredient in drilling muds, contains several heavy metals, including compounds of lead, cadmium, mercury, and arsenic.[103] Will drilling mud solids containing lead, cadmium, mercury, and arsenic be allowed to be stored in the reserve pit on a long-term basis?
- What type of testing will be conducted to demonstrate that the reserve pit liner was not damaged during use, and to ensure that the liner provides an impermeable barrier for long-term ground water protection?
- What maintenance, testing and repair requirements will be put in place to ensure liner integrity?

Unless there is an environmentally compelling reason to allow long-term disposal at onsite reserve pits, the preferred cleanup plan would be to remove all materials from temporary reserve pits, test waste material, and process it according to federal waste handling requirements at a licensed treatment and disposal site.

If a reserve pit is determined to be an environmentally preferable temporary storage solution, the reserve pit should be fenced and netted to prevent wildlife and livestock from accessing the reserve pit.

18. Wellbore Plugging & Abandonment Requirements

Recommendation No. 25: NYS regulations should clearly state when future Marcellus Shale wells must be plugged and abandoned, and this should be retroactively applied to existing wells that are no longer operating and may pose a risk to the environment.

Part 555 of 6 NYCRR requires gas wells to be permanently plugged and abandoned (P&A'd), but NYS's regulations do not provide specific criteria to determine when a well must be P&A'd. An operator may submit a "Notice of Intention to Plug and Abandon" a well, but it appears to be a voluntary, operator-initiated action. Alternatively, NYSDEC allows operators to shut-in wells or temporarily abandon wells without plugging, for what appears to be an indefinite time period. Historically, temporarily abandoned wells have been the source of environmental damage, because operators are not present to monitor wellbore integrity on a routine basis and wellbore infrastructure can corrode and erode, failing over time.[104]

[103] Rae, P. BJ Services Company, "Towards Environmentally-Friendly Additives for Well Completion and Stimulation Operations," Society of Petroleum Engineering Paper 68651, 2001.

[104] As a case in point, the 2009 catastrophic well leak in the Australian Timor Sea resulted from an improperly handled temporarily suspended well.

NYS regulations should clearly state the P&A requirements for a Marcellus Shale well. The regulations should define the best technology and practices for determining at what point in time a well must be P&A'd. The regulations should also specify the procedures required to properly abandon horizontal and multi-lateral wellbores. Most states limit temporary abandonment to a one-year period of time, with a wellbore integrity monitoring program requirement to ensure that the well is not leaking during temporary abandonment.

The revised regulations should retroactively apply to existing wells that are no longer in operation and may pose a risk to the environment. As a priority, NYSDEC should carefully examine and require wells to be plugged and abandoned in close proximity to drinking water sources, and in areas under consideration for new high-volume fracture treatments.

19. Well Control & Emergency Response Planning

Recommendation No. 26: NYS regulations should be updated to include best practices for well control and emergency response planning.

The DSGEIS does not require an emergency response plan, or well blowout control plan, in the event of a fire, explosion, or blowout. Best practices include developing and testing these types of plans prior to drilling. The capacity of local emergency response teams to take on potentially catastrophic fire and explosion hazards must be evaluated in the DSGEIS. NYSDEC must determine whether local emergency response capability exists, or if operators should be required to supplement emergency response with additional equipment, personnel, and training.

Joint industry and local emergency response planning and training is considered best practice. It ensures local emergency response personnel and equipment will be able to provide support in an actual emergency, and that industry and local team response can be effectively and efficiently integrated.[105] For example, well site roadways or access may be difficult for standard firefighting, rescue, and emergency medical services vehicles to access. Emergency response equipment may not have sufficient ground clearance to traverse the typically narrow dirt roads. Fire and rescue services should be aware of the areas and test drive the access roads to ensure that vehicles can gain access to sites.

NYS regulations at 6 NYCRR § 556.2(c) require all gas wells capable of production to be equipped with wellhead controls adequate to contain and control gas flow. This regulation does not require an operator to install a fail-safe automatic surface controlled subsurface safety valve (SSSV) system capable of preventing an uncontrolled gas release in the event wellhead surface safety valves fail, or the wellhead is damaged. Many states require the use of SSSVs to provide a redundant prevention system.

20. Hazardous Air Pollution Control

Recommendation No. 27: NYS regulations should include best technology and practices to reduce hazardous air pollution to the lowest possible level.

Dehydration Units: Dehydrator units are required to remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water, and in the process the TEG

[105] Penn State Extension, Marcellus Shale: What Local Government Officials Need to Know; www.naturalgas.psu.edu. 2009.

absorbs methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs); these gases are vented to atmosphere unless pollution controls are installed on the dehydration units. Best technology includes installation of flash-tank separators to recover the gas pollutants, or routing vapors to a vapor collection/destruction unit.

The DSGEIS does not require installation of flash-tank separators to control hazardous air pollutants, and provides conflicting information on the estimated dehydration unit throughput. It's also unclear as to whether or not pollution control will be required at a federal level. Section 6.5.1.2 of the DSGEIS concludes that dehydration units used for the gas development will be exempt from EPA's National Emission Standards for Hazardous Air Pollutants (NESHAP) since gas production is estimated to be below 3 MMscfd[106] and benzene emissions are estimated to be below 1 tpy. Yet, this conclusion conflicts with NYSDEC's consultant report (ICF International's August 2009, Subtask 2.5), that concludes: *"Information gathered by NYSERDA and NYS DEC field trips to Marcellus Shale well sites indicate a potential production rate of 7 to 10 MMscf per day."*

NYS regulations should require installation of flash-tank separators to control hazardous air pollutants. Alternatively, desiccant dehydrators can be used in place of TEG dehydrators; these units have shown to cost less, have lower operating and maintenance costs, and control 99% of HAPs.[107]

Impoundments: The DSGEIS estimates that a very large amount of hazardous air pollution (methanol) may be present at central impoundments (32.5 tons per year),[108] and gives inconsistent approaches to pollution mitigation.[109] EPA lists methanol as a hazardous air pollutant, but has not yet classified methanol with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not understood.[110] Testing in rats yielded skeletal, cardiovascular, urinary system, and central nervous system malformations.[111] Chronic inhalation or oral exposure may result in headache, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness in humans. Neurological damage, specifically permanent motor dysfunction, may also result.[112]

The EPA lists a major source of hazardous air pollution if more than 10 tons of a listed HAP is released per year. The DSGEIS proposes to allow the Marcellus Shale impoundment to pollute the air at a level more than three times this major source HAP threshold. The best practice is to use a closed loop collection and tank system, rather than impoundments. Vapors should be routed to an air pollution control device to filter or destroy HAPS.

Benzene: The DSGEIS does not estimate significant amounts of benzene emissions; however, recent reports indicate the Texas Commission on Environmental Quality is finding surprisingly high levels of benzene emitted from Barnett Gas Shale activities in Texas.[113] Additional analysis is warranted to better

[106] MMscfd= millions of standard cubic feet of gas per day.
[107] Fernandez, R., Petrusak, R., Robinson, D., Zavadil, D., Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.
[108] DSGEIS, p. 6-57.
[109] DSGEIS at pgs. 7-55, 7-88, 7-89, and 7-90.
[110] http://www.epa.gov/ttn/atw/hlthef/methanol.html
[111] American Conference of Governmental Industrial Hygienists (ACGIH), TLVs and BEIs, Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices, Cincinnati, OH, 1999.
[112] The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.
[113] Dr. Michael Honeycutt, Head of TCEQ's Toxicology Division, quoted in WFAA-TV new report, November 20, 2009. Dr. Michael Honeycutt "was shocked to see air sampling revealed high levels of benzene, a cancer-causing toxin, near some natural gas facilities."

understand and quantify the potential benzene exposure because it is a known, EPA-listed human carcinogen. Best control technologies should be identified and codified in regulation.

21. Compressor Stations, Pipelines, and Gas Processing Facilities

Recommendation No. 28: NYSDEC should include compressor stations, gathering pipelines, and gas processing facilities in the DSGEIS, and identify best technology and practices for this equipment.

The DSGEIS states that compressor stations and pipelines are not within the scope of the DSGEIS. No best technologies or practices are evaluated. In its December 15, 2008 scoping comments to NYSDEC, the NRDC and co-signatories requested that gathering pipelines and gas treatment facilities be included and analyzed in the DSGEIS. NYSDEC should include compressor stations, gathering pipelines, and gas processing facilities in the DSGEIS, and identify best technologies and practices for this equipment.

22. NYSDEC Inspection and Enforcement Program

Recommendation No. 29: NYSDEC must demonstrate in the DSGEIS that it has the personnel, equipment, technical expertise, and funding to carry out the inspection and enforcement procedures listed in the DSGEIS.

In its December 15, 2008 scoping comments to NYSDEC, the NRDC and its co-signatories requested the DSGEIS describe the current inspection program for gas wells including: budget, number of inspectors, inspector qualifications and expertise, and frequency of inspections. The DSGEIS does not demonstrate that NYSDEC has sufficient resources to oversee, inspect, and enforce Marcellus Shale gas development. A manpower and resource analysis specific to the Marcellus Shale gas development is needed.

23. Financial Assurance Amount

Recommendation No. 30: NYSDEC should require financial assurance adequate to fund long-term monitoring, publicly incurred response costs and the cost of properly remediating and abandoning operations.

In its December 15, 2008 scoping comments to NYSDEC, the NRDC and its co-signatories requested the DSGEIS examine whether NYSDEC requires sufficient financial assurance (in the form of a bond or other financial instrument) to ensure there is funding available to properly plug and abandon wells, remove equipment and contamination, complete surface restoration, and compensate nearby public for adverse impacts (e.g., well contamination). Long horizontal wells are more costly to plug and abandon than vertical wells. Also, surface impacts will be larger due to planned high-volume fracture stimulation treatments, multiple wells drilled from a single well pad, and the need for additional gas treatment and transportation facilities. Some states require as much as $100,000 to cover a single well. Yet, the DSGEIS does not provide an analysis on the current financial assurance requirements.