UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 5

Natural Resources Defense Council, Earthjustice, and Sierra Club, *Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels* (June 29, 2011)

January 27, 2012

June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

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[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.

[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.

[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.

[4] *Id.*; *see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g. , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

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[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling "kicks" or "shows." These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials

must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:
Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:
Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:
Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:
To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the

casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:
If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:
For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term "cement bond log" refers to out-dated technology and the terms "cement evaluation logs," "cement integrity logs" or "cement mapping logs" are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:

Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:

Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:

These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:

Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run

before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of "injection." Operators should also run caliper and resistivity logs. The term "fracture finder logs" refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to

characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger

human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

WHAT SHOULD THE PERMIT DURATION BE AND HOW SHOULD CLASS II PLUGGING AND ABANDONMENT PROVISIONS BE ADDRESSED FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators

must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

    e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

  Operators should also consider testing for environmental tracers to determine groundwater age.

2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
    a. Mineralogy
    b. Petrology
    c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

    c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW
10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

HOW COULD CLASS II FINANCIAL RESPONSIBILITY REQUIREMENTS BE MET FOR WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

WHAT PUBLIC NOTIFICATION REQUIREMENTS OR SPECIAL ENVIRONMENTAL JUSTICE CONSIDERATIONS SHOULD BE CONSIDERED FOR AUTHORIZATION OF WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

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UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 6

Sierra Club, et al., *Comments on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO,* Docket No. EPA-HQ-OAR-2010-0505 (Nov. 30, 2011)

January 27, 2012

BEFORE THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO	))))	**Docket No. EPA-HQ-OAR-2010-0505** *Via regulations.gov and e-mail* *November 30, 2011*

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I. INTRODUCTION

Thank you for accepting these comments on behalf of the Sierra Club, the Center for Biological Diversity, Clean Air Council, the Clean Air Task Force, Earthjustice, Earthworks, the Environmental Defense Fund, the Natural Resources Defense Council, the Network for Oil and Gas Accountability and Protection, the San Juan Citizens Alliance, WildEarth Guardians, the West Virginia Surface Owners' Rights Organization, and the Wyoming Outdoor Council. Collectively, we represent millions of members, including many thousands who live and recreate in areas affected by oil and gas operations. On behalf of our members, we thank EPA for updating and expanding the performance standards for this industry, which is rapidly expanding across the United States.

EPA's proposed New Source Performance Standards (NSPS) for the oil and natural gas industry are a long awaited and much needed update. EPA originally included crude oil and natural gas production on the list of air pollution sources that require a NSPS in

1979.[1] Since then, EPA has only promulgated standards for natural gas processing plants, an extremely limited subset of facilities within the industry.[2] EPA failed to regulate oil and gas facilities that emit substantial amounts of air pollution, such as wells, pipelines, and any compressors, valves or storage tanks not located at processing plants. Since EPA last revised the NSPS for this sector, the growth of hydraulic fracturing and horizontal drilling has led to the unprecedented expansion of the oil and gas industry into new areas. This expansion, along with existing development in established oil and gas producing regions, has substantial negative impacts to public health and the environment.

EPA's proposed NSPS contains some good first steps towards addressing the increasing emissions and air pollution from this industry. In particular, we applaud EPA's decision to expand the NSPS to address hydraulic fracturing at well-sites and to cover additional oil and gas facilities, such as compressors, pneumatic controllers, and storage vessels. However, there is still more to be done to make these standards fully compliant with the rigorous requirements of Section 111 of the Clean Air Act.[3]

In Part I of our comments, we review EPA's basic legal obligations under Section 111 and provide an overview of the expanding oil and gas industry and the need for strong air quality regulations. Building on that foundation, in Part II, we provide a technical review of EPA's proposed standards and compare them to those statutory obligations. We identify important gaps in the standards, such as the failure to regulate air emissions from conventional gas wells (those which do not use hydraulic fracturing) or oil wells of any type.

Parts III, IV, and V of our comments address critical gaps in the proposal. EPA has failed to regulate certain sources of pollution, including offshore facilities, oil- and gas-field heater-treaters, and drilling rigs. EPA also has failed to regulate pollutants emitted by the industry, including methane, particulate matter, hydrogen sulfide, and nitrogen oxides. And EPA has failed to regulate many existing sources of pollution, even though they are responsible for the lion's share of the current emissions. We discuss what the law and the scientific evidence require of EPA in each instance.

In Part VI, we address EPA's enforcement and compliance obligations under the statute, which necessitate important changes to EPA's proposal, including retaining oil and gas sector sources in the Title V program, and eliminating EPA's illegal proposed affirmative defense.

In Part VII, we explain how EPA overestimated the costs of air pollution controls and underestimated the benefits. Part VIII demonstrates that industry growth and rigorous

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[1] 44 Fed. Reg. 49,222 (Aug. 21, 1979), attached hereto as Exhibit 1.
[2] 40 C.F.R. Part 60, Subparts KKK & LLL.
[3] 42 U.S.C. § 7411 *et seq.*

clear air regulations can go hand in hand. In fact, the industry has continued to grow despite regulations of the sort that EPA proposes.

In Part IX, we strongly urge EPA to close as many of the gaps in the proposed rule as possible, without delaying finalization by April 3, 2012, as is legally required. In Part X, we emphasize, however, that to the extent that certain obligations simply cannot be met by that date, EPA may not defer any remaining necessary rulemakings indefinitely. Should any necessary rulemaking activity remain beyond this deadline, EPA must complete it by 2013, rather than allowing its already illegally long failure to fully regulate this major industry to persist. EPA may, under no circumstances, defer rulemaking until its next review, which is not required to occur for another eight years. During any delay, unacceptable air pollution will continue to be caused by the industry's improperly controlled emissions.

Several reports from recognized experts support our positions. They are attached to these comments, and incorporated by reference.
Throughout this report, we make many recommendations, which are intended to bring EPA's proposal into compliance with the Clean Air Act. EPA must respond to each recommendation in full. If it opts not to take a recommendation, EPA must explain its rationale in its response to comments.

A. Legal Overview of Section 111 of the Clean Air Act

Section 111 of the Clean Air Act ("CAA" or "Act") requires EPA to set technology-based standards of performance for industrial sources of air pollution.[4] These federal standards of performance apply to all new and modified sources in a listed source category.[5] Because these standards apply to sources in designated or "listed" industrial categories regardless of the ambient air quality in a particular area, they help to prevent new air pollution problems as well as prevent existing problems from worsening. These goals are particularly important with respect to the oil and gas industry, which is responsible for substantial existing air pollution problems and is rapidly expanding into new areas. [6]

[4] *See* 42 U.S.C. § 7411.
[5] 42 U.S.C. 7411(b)(1)(B), (a)(2).
[6] The emission limits established by the standard must be met by sources within listed categories that commence construction or undergo modification after the date of the *proposal* of such standard. *See* 42 U.S.C. §§ 7411(a)(2) (a "new source" is "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance"). Any new source within a listed category that begins operation or any existing source that receives, or should receive, a permit to undergo a modification under Section 111 after the published date of the proposal for the standard must therefore comply with the standard EPA promulgates in the final rule.

New source performance standards must be promulgated on a rigorous timeline, which EPA failed to meet for this industry. Section 111(b)(1)(A) provides:

> The Administrator *shall*, within 90 days after December 31, 1970, publish (and from time to time thereafter *shall* revise) a list of categories of stationary sources. [Sh]e *shall* include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.[7]

Section 111 further provides that within one year following the listing of each such source category, EPA "*shall* publish proposed regulations, establishing Federal standards of performance."[8] Once EPA establishes the standards of performance, it "*shall*, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[9]

EPA first proposed new source performance standards for the oil and natural gas industry in 1985.[10] EPA therefore was required to review and revise its 1985 standards no later than 1993. Air pollution emissions from this sector have grown in the interim, and although available control techniques have markedly improved, they have not been consistently applied, because of the delay in revising the requirements to do so. For that reason, it is essential that EPA comply with section 111's high standards in finalizing this rule, as so many sources have gone uncontrolled for so long. Specifically, EPA's updated "standard of performance" must meet the statutory definition:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[11]

"This section directs EPA to set specific and rigorous limits on the amounts of pollutants that may be emitted from any 'new source' of air pollutants" and "reflect a commitment to requiring the best technology."[12] This "best demonstrated technology" ("BDT") or

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[7] 42 U.S.C. § 7411(b)(1)(A) (emphases added).
[8] *Id.* § 7411(b)(1)(B) (emphasis added).
[9] *Id.* (emphasis added).
[10] *See* 50 Fed. Reg. 26122 (June 24, 1985) (promulgation of VOC NSPS covering leaking components as onshore natural gas processing plants), attached hereto as Exhibit 1; 50 Fed. Reg. 40158 (Oct. 1, 1985) (promulgation of NSPS for SO_2 emissions from natural gas processing plants), attached hereto as Exhibit 2.
[11] 42 U.S.C. § 7411(a)(1).
[12] *ASARCO Inc. v. EPA*, 578 F.2d 319, 322 & 322 n.6 (D.C. Cir. 1978), attached hereto as Exhibit 3.

"best system of emission reduction"("BSER") standard[13] is designed to "enhance air quality and not merely to maintain it" by "forcing all newly constructed or modified [facilities] to employ pollutant control systems" that will reflect the best demonstrated system of reduction."[14]

Section 111 is a technology-forcing program. Congress' intent was "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution."[15] As such, the courts are clear that the "standards should be stringent in order to force the development of improved technology."[16] As the D.C. Circuit has explained, "[s]ection 111 looks toward what may fairly be projected for the regulated future, rather the state of the art at present, since it is addressed to standards for new plants."[17] The required technology need not "be in actual routine use somewhere"; rather, the "essential question," is "whether the [required] technology would be available for installation in new plants."[18]

Because EPA is to set standards that new sources in the industry can meet in the future,[19] it need not set a standard that can be met by every plant "currently in operation . . . at all times and under all circumstances."[20] In other words,

> An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.[21]

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[13] EPA refers to the standard as "BSER" in this rulemaking, though BDT is the traditional abbreviation . We do not understand EPA's terminological choice to reflect a change in its interpretation of the statute, but the agency must say so, if it is changing its view. We use the terms interchangeably in these comments, understanding both to require emissions limits meeting the statutory standard at each individual facility covered by the standard.

[14] *ASARCO* at 327; *see also Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785-86 (D.C. Cir. 1976) (discussing these standards), attached hereto as Exhibit 4.

[15] *Sierra Club v. Costle,* 657 F.2d 298, 347 n.174 (D.C. Cir. 1981) (quoting legislative history), attached hereto as Exhibit 5. *See also ASARCO, Inc. v. EPA,* 578 F.2d 319, 322 & n.6 (D.C. Cir. 1978) (The language of section 111 evinces the Congressional "commitment to requiring the best technology" as "[NSPS] are designed to force new sources to employ the best demonstrated systems of emission reduction.")

[16] *ASARCO* at 325.

[17] *Id.* at 391.

[18] *Id. See also Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (Achievability "'looks toward what may be fairly projected for the regulated future, rather that the state of the art at present'", attached hereto as Exhibit 6. (quoting *Portland Cement*, 486 F.2d at 391).

[19] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-92 (D.C. Cir. 1973), attached hereto as Exhibit 7.

[20] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973), attached hereto as Exhibit 8.

[21] *Id*. at 433. *See also Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 (D.C. Cir. 1980) (achievability is determined "for the industry as a whole."), attached hereto as Exhibit 9.

Whether a "system of emission reduction" is achievable and has been adequately demonstrated is a question of reasonableness: [22]

> An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.[23]

While EPA is to consider the costs "of achieving [the] reduction" (along with nonair quality health and environmental impacts and energy requirements) when setting a standard of performance, EPA must not lose sight of the technology forcing nature of section 111.[24] The cost issue before the agency is whether the cost of new source control is "greater than the industry could bear and survive." [25]

Where it is "not feasible to prescribe or enforce a standard of performance," EPA must instead "promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction" which is adequately demonstrated.[26] This authority is limited by the Act, which defines the narrow circumstances in which it is "not feasible" to set a standard of performance, including when EPA determines that "a pollutant or pollutants cannot be emitted through a conveyance" capable of capturing such pollutants or that "the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."[27]

Finally, EPA's standard-setting obligations extend to existing sources of some air pollutants. For air pollutants that are not criteria pollutants listed under section 108 or hazardous air pollutants listed and regulated under 112, EPA must prescribe regulations setting out existing source performance standard requirements, to be adopted and implemented by the states.[28]

B. Overview of the Oil and Gas Industry.

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[22] In determining what technologies are "adequately demonstrated" to form the basis for an "achievable" performance standard for a particular source category, courts have held that EPA's analysis can – indeed should, as appropriate – look beyond facilities within the United States. EPA may base its standards on the application of systems of control that are in use in other countries, as well as looking at technology transfers across industries as the basis for an "achievable" performance standard, "*Lignite Energy Council*, 198 F.3d at 933-34 & n.3.

[23] *Id.*

[24] *Lignite Energy Council*, 198 F.3d at 933 (citing *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992)).

[25] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) ("*Portland Cement II*"), attached hereto as Exhibit 10; *see also Lignite Energy Council*, 198 F.3d at 933 (EPA may exclude emission controls that would impose "exorbitant" economic or environmental costs).

[26] 42 U.S.C. § 7411(h)(1).

[27] *Id.* § 7411(h)(2).

[28] *See* 42 U.S.C. § 7411(d).

1. The oil and gas industry is rapidly expanding

Oil and gas development in the United States is on the rise. In 2009, there were over a million wells producing oil and natural gas nationwide.[29] This includes conventional onshore and offshore oil and gas production as well as unconventional coal bed methane, tight gas, and shale oil and gas production.[30] Although the mix of production from these sources is likely to change, the U.S. Energy Information Administration ("EIA") predicts increases in both domestic crude oil and natural gas production over the near term.[31] The EIA predicts that crude oil development will rise until around 2019 and then fall off slightly, and that there will be substantial increases in overall natural gas production between 2009 and 2035.[32] With respect to natural gas development, the EIA predicts drilling will increase by 190% in shale reservoirs, by 138% in tight sands, and by 61% in coalbed methane reserves.[33]

The dramatic rise in shale development is the result of advances in hydraulic fracturing and horizontal drilling that have allowed the industry to unlock oil and gas trapped in shale formations that was previously inaccessible. Successful shale gas production started in the Barnett Shale of north central Texas in the early years of the past decade.[34] Since then, the growth of shale gas development has been extremely rapid. Natural gas now provides approximately 25% of the domestic energy supply.[35] Although shale gas made up less than 2% of gas production in 2001, it now constitutes around 30%.[36] That trend is expected to continue: the EIA predicts shale gas will be 47% of production by 2035.[37]

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[29] EPA, *Proposed Amendments to Air Regulations for the Oil and Natural Gas Industry, Fact Sheet*, at 2, *available at* http://epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf (hereinafter "EPA Fact Sheet"), attached hereto as Exhibit 11.

[30] EIA, *Annual Energy Outlook 2011*, at 79, 82, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, attached hereto as Exhibit 12.

[31] EPA, *Regulatory Impact Analys*is ("RIA") at 2-26 to 2-28; *see also* EIA, Annual Energy Outlook 2011, at 79, 82.

[32] RIA at 2-28; *see also* EIA, Annual Energy Outlook 2011, at 79, 82.

[33] RIA at 2-27.

[34] EIA, *Annual Energy Outlook 2011, Prospects for Shale Gas*, *available at* http://www.eia.gov/forecasts/aeo/IF_all.cfm#prospectshale, attached hereto as Exhibit 13; *see also* Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), *available at* http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf. (hereinafter "Barnett Shale Report"), attached hereto as Exhibit 14.

[35] U.S. Dep't of Energy, Secretary of Energy Advisory Board, *Shale Gas Production Subcommittee 90-Day Report*, at 6 (Aug. 18, 2011). (hereinafter "SEAB Interim 90-Day Report"), *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf, attached hereto as Exhibit 15.

[36] *Id.*; *see also* U.S. Energy Information Administration (EIA), *Outlook for Natural Gas*, at slide 14 (2010), *available at* http://205.254.135.24/neic/speeches/newell101110.ppt (showing 14-fold increase in shale gas development between 200 and 2010, with sharp increase after 2008), attached hereto as Exhibit 16.

[37] EIA, *Outlook for Natural Gas*, at slide 14; *see also* SEAB 90-Day Report at 6-7.

Shale gas production is expected to increase in almost every region of the country, including the Northeast, Gulf Coast, Midcontinent, Southwest, and Rocky Mountain regions.[38] The increase will be dramatic in the Marcellus shale in Northeast, which has only recently been subject to significant shale gas development. Already, Pennsylvania is experiencing large increases in drilling.[39] Even states with a long-history of oil and gas development, such as Colorado and Wyoming, have experienced and will continue to experience shale gas development in new areas.[40]

Development of shale oil is also on the rise.[41] Since the beginning of 2008, the number of active oil rigs has increased 242%, reaching a 24-year high in October of this year.[42] Much of this increase is attributable to development of shale oil plays, such as the Bakken in North Dakota, that are now accessible because of hydraulic fracturing and horizontal drilling techniques.[43] Although shale oil production was negligible a few years ago, industry estimates that it could reach 2 million barrels per day in the next five years.[44]

2. The oil and gas industry is responsible for substantial amounts of emission and air pollution that is harmful to public health and the environment

Oil and gas development includes numerous stages and facilities, all of which contribute to substantial amounts of air emissions and resultant dangerous air pollution. EPA has defined the "oil and gas sector" for the purposes of this rule to include the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas.[45] As depicted below, the sector includes four stages: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission, and (4) natural gas distribution.[46]

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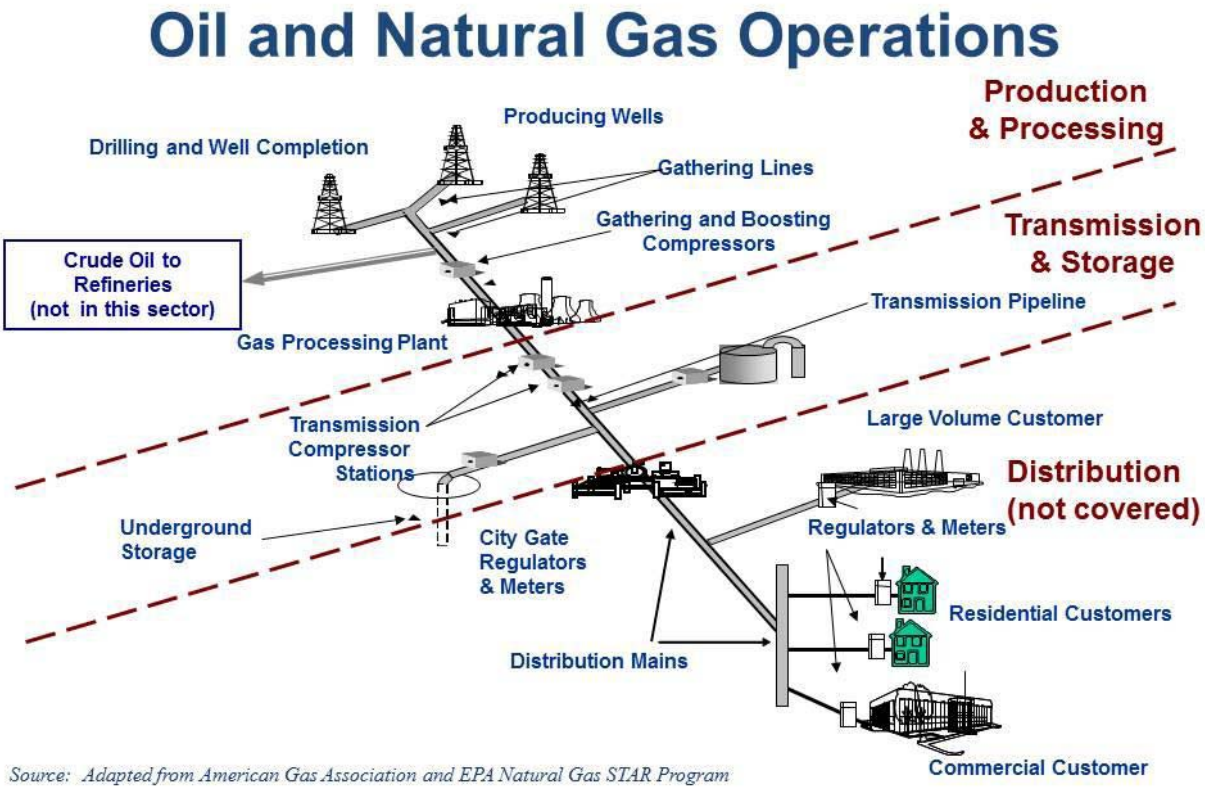
[38] EIA, *Annual Energy Outlook 2011*, at 80.
[39] *SEAB Interim 90-Day Report* at 8.
[40] *Id*.
[41] EIA, *Annual Energy Outlook 2011*, at 82.
[42] *See* Update 2—U.S. Oil Rig Count Hits Record—Baker Hughes, *available at* http://uk.reuters.com/article/2011/10/14/energy-oil-rigs-idUKN1E79D11420111014.http://uk.reuters.com/article/2011/10/14/energy-oil-rigs-idUKN1E79D11420111014, attached hereto as Exhibit 17.
[43] *Id.*
[44] *Id.*
[45] 76 Fed. Reg. 52744. at 52,738, 52,744 (Aug. 23, 2011).
[46] EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules* ("TSD") at 2-4 (July 2011).

Figure 1: The Oil and Natural Gas Sector



Within these development stages, the major sources of air pollution include wells, compressors, pipelines, pneumatic devices, dehydrators, storage tanks, pits and ponds, natural gas processing plants, and trucks and construction equipment. Major air pollutants of concern from these operations include methane (CH_4), volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and particulate matter (PM_{10} and $PM_{2.5}$). Oil and natural gas operations also emit listed hazardous air pollutants (HAPs), which are regulated separately by National Emissions Standards for Hazardous Air Pollutants (NESHAPs); our comments on the proposed NESHAPs for the oil and gas industries are presented in a separate document.

Methane: Methane is the dominant pollutant from the oil and gas sector. Emissions occur as result of intentional venting or unintentional leaks during drilling, production, processing, transmission and storage, and distribution. For example, methane is emitted when wells are completed and vented, as part of operation of pneumatic devices and compressors, and as a result of leaks (fugitive emissions) in pipelines, valves, and other equipment. EPA has identified natural gas systems as the "single

largest contributor to United States anthropogenic methane emissions."[47] The industry is responsible for over 40% of total U.S. methane emissions, which amounts to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[48]

Methane is a potent greenhouse gas that contributes substantially to global climate change. Methane has at least 25 times the global warming potential of carbon dioxide over a 100 year time frame and at least 72 times the global warming potential of carbon dioxide over a 20-year time frame.[49]

Because of methane's effects on climate, EPA has found that methane, along with five other well-mixed greenhouse gases, endanger public health and welfare within the meaning of the Clean Air Act.[50] The impacts of climate change caused by methane and other greenhouse gases include "increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise."[51] A warming climate will also lead to loss of coastal land in densely populated areas, shrinking snowpack in Western states, increased wildfires, and reduced crop yields.[52] More frequent heat waves as a result of global warming have already affected public health, leading to premature deaths. And threats to public health are only expected to increase as global warming intensifies. For example, a warming climate will lead to increased incidence of respiratory and infectious disease, greater air and water pollution, increased malnutrition, and greater casualties from fire, storms, and floods.[53] Vulnerable populations—such as children, the elderly, and those with existing health problems—are the most at risk from these threats.

Methane also reacts in the atmosphere to form ozone.[54] As we discuss below, ozone is a major public health threat, linked to a wide range of maladies. Ozone can also damage vegetation, agricultural productivity, and cultural resources. Ozone is also a

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[47] 76 Fed. Reg. at 52,792.
[48] *Id.* at 52,791–92.
[49] *IPCC 2007—The Physical Science Basis*, Section 2.10.2, attached hereto as Exhibit 18. We note that these global warming potential figures may be revised upward in the next IPCC report. As discussed in the attached report of Dr. Laurie Johnson (See Exhibit 249), discussed below, another more recent study by Shindell *et al.* estimates methane's 100-year GWP at 33; this same source estimates methane's 20-year GWP at 105.
[50] EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding"), attached hereto as Exhibit 19.
[51] 76 Fed. Reg. at 52,791-22 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011), http://www.epa.gov/climateexchange/emissions/downloads11/US-GHGInventory-2011-ExecutiveSummary.pdf), attached hereto as Exhibit 20.
[52] *Id.* at 66,532–33.
[53] EPA, *Climate Change, Health and Environmental Effects*, *available at* http://epa.gov/climatechange/effects/health.html, attached hereto as Exhibit 21.
[54] 76 Fed. Reg. at 52,791; RIA at 4-27.

significant greenhouse gas in its own right, meaning that methane is doubly damaging to climate – first in its own right, and then as an ozone precursor.

***VOCs and NO_x*:** VOCs and NO_x contribute to the formation of ground-level ozone (also referred to as smog). Smog pollution harms the respiratory system and has been linked to premature death, heart failure, chronic respiratory damage, and premature aging of the lungs.[55] Smog may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[56]

Significant ozone pollution also damages plants and ecosystems.[57] Ozone also contributes substantially to global climate change over the short term. According to a recent study by the United Nations Environment Program (UNEP), behind carbon dioxide and methane, ozone is now the third most significant contributor to human-caused climate change.[58]

The oil and gas industry is a major source of the ozone precursors VOCs and NO_x.[59] VOCs are emitted from well drilling and completions, compressors, pneumatic devices, storage tanks, processing plants, and fugitives from production and transmission.[60] The primary sources of NO_x are compressor engines, turbines, and other engines used in drilling and hydraulic fracturing.[61] NO_x is also produced when gas is flared or used for heating.[62]

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[55] RIA at 4-25; Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), *available at* http://www.nejm.org/doi/full/10.1056/NEJMoa0803894#t=articleTop, attached hereto as Exhibit 22.

[56] *See* EPA, *Ground-Level Ozone, Health Effects*, *available at* http://www.epa.gov/glo/health.html attached hereto as Exhibit 23. EPA, Nitrogen Dioxide, Health, available at http://www.epa.gov/air/nitrogenoxides/health.html, attached hereto as Exhibit 24.

[57] RIA at 4-26.

[58] *Id. See also* United Nations Environment Programme and World Meteorological Organization, (2011): *Integrated Assessment of Black Carbon and Tropospheric Ozone: Summary for Decision Makers* (hereinafter "UNEP Report," available at http:// www.unep.org/dewa/Portals/67/pdf/Black_Carbon.pdf), at 7, attached hereto as Exhibit 25.

[59] *See, e.g.,* EPA Fact Sheet at 3; Barnett Shale Report at 24.

[60] *See, e.g.,* TSD at 4-7, 5-6, 6-5, 7-9, 8-1; *see also* Barnett Shale Report at 24.

[61] *See, e.g.,* TSD at 3-6; *See also* Barnett Shale Report at 24. *Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project* at 11 (Table 2.1).

[62] TSD at 3-6; Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011), available at http://www.cdphe.state.co.us/ap/RegionalHaze/AppendixD/4-FactorHeaterTreaters07JAN2011FINAL.pdf, attached hereto as Exhibit 26.

As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas Fort Worth area in Texas is home to substantial oil and gas development. Within the Barnett shale region, as of September 2011, there were more than 15,306 gas wells and another 3,212 wells permitted.[63] Of the nine counties surrounding the Dallas Forth Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[64] A 2009 study found that summertime emissions of smog-forming pollutants from these counties were roughly comparable to emissions from motor vehicles in those areas.[65]

Oil and gas development has also brought serious ozone pollution problems to rural areas, such as western Wyoming.[66] On March 12, 2009, the governor of Wyoming recommended that the state designate Wyoming's Upper Green River Basin as an ozone nonattainment area.[67] The Wyoming Department of Environmental Quality conducted an extended assessment of the ozone pollution problem and found that it was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."[68] Last winter alone, the residents of Sublette County suffered thirteen days with ozone concentrations considered "unhealthy" under EPA's current air-quality index, including days when the ozone pollution levels exceeded the worst days of smog pollution in Los Angeles.[69] Residents have faced repeated warnings regarding elevated ozone levels and the resulting risks of going outside.[70]

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[63] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf (Accessed Nov. 21, 2011), attached hereto as Exhibit 27.
[64] Barnett Shale Report at 1, 3.
[65] *Id.* at 1, 25-26.
[66] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415, attached hereto as Exhibit 28.
[67] *See* Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8-Hour Ozone Designation Recommendations"), *available at* http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf, attached hereto as Exhibit 29; Wyoming Department of Environmental Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin (March 26, 2009) ("Wyoming Nonattainment Analysis"), at vi-viii, 23-26, 94-05, *available at* http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf, attached hereto as Exhibit 30.
[68] Wyoming Nonattainment Analysis at viii.
[69] EPA, *Daily Ozone AQI Levels in 2011 for Sublette County, Wyoming*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=countycode&msaorcountyValue=56035&poll=44201&county=56035&msa=-1&sy=2011&flag=Y&_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas, attached hereto as Exhibit 31.; *see also* Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, *available at* http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1, attached hereto as Exhibit 32.
[70] *See, e.g., 2011 DEQ Ozone Advisories*, Pinedale Online! (Mar. 17, 2011) (documenting ten ozone advisories in February and March 2011), *available at*

Ozone problems are mounting in other Rocky Mountain states as well. Northeastern Utah recorded unprecedented ozone levels in the Uintah Basin in 2010 and 2011. In the first three months of 2010—which was the first time that winter ozone was monitored in the region—air quality monitors measured more than 68 exceedances of the federal health standard. On three of these days, the levels were almost twice the federal standard.[71] Between January and March 2011, there were 24 days where the National Ambient Air Quality Standard (NAAQS) for ozone were exceeded in the area. Again, ozone pollution levels climbed to nearly twice the federal standard.[72] The Bureau of Land Management (BLM) has identified the multitude of oil and gas wells in the region as the primary cause of the ozone pollution.[73]

Rampant oil and gas development in Colorado and New Mexico is also leading to high levels of VOCs and NO_x. In 2008, the Colorado Department of Public Health and Environment concluded that the smog-forming emissions from oil and gas operations exceed vehicle emissions for the entire state.[74] Moreover, significant additional drilling has occurred since 2008. Colorado is now home to more than 46,000 wells.[75] There is also significant development in the San Juan Basin in southeastern Colorado and northwestern New Mexico, with approximately 35,000 wells in the Basin. As a result of this development and several coal-fired power plants in the vicinity, the Basin suffers

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http://www.pinedaleonline.com/news/2011/03/OzoneCalendar.htm, attached hereto as Exhibit 33; Wyoming Department of Environmental Quality, Ozone Advisory for Monday, Feb. 28, Pinedale Online! (Feb. 27, 2011), *available at* http://www.pinedaleonline.com/news/2011/02/OzoneAdvisoryforMond.htm, attached hereto as Exhibit 34

[71] Scott Streater, *Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future*, N.Y. TIMES, Oct. 1, 2010, *available at* http://www.nytimes.com/gwire/2010/10/01/01greenwire-air-quality-concerns-may-dictate-uintah-basins-30342.html?pagewanted=1 (last visited Sept. 28, 2011), attached hereto as Exhibit 35.

[72] *See* EPA, AirExplorer, Query Concentrations (Ozone, Uintah County, 2011), available at http://www.epa.gov/cgi-bin/htmSQL/mxplorer/query_daily.hsql?msaorcountyName=countycode&msaorcountyValue=49047&poll=44201&county=49047&site=-1&msa=-1&state=-1&sy=2011&flag=Y&query=download&_debug=2&_service=data&_program=dataprog.query_daily3P_dm.sas, attached hereto as Exhibit 36.

[73] BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact State*ment ("GASCO DEIS"), at 3-13, *available at* http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_/gasco_energy_eis.html, attached hereto as Exhibit 37.

[74] Colo. Dept. of Public Health & Env't, Air Pollution Control Division, Oil and Gas Emission Sources, *Presentation for the Air Quality Control Commission Retreat*, at 3-4 (May 15, 2008), attached hereto as Exhibit 38.

[75] Colorado Oil & Gas Conservation Commission, *Colorado Weekly & Monthly Oil and Gas Statistics*, at 12 (Nov. 7, 2011), available at http://cogcc.state.co.us/ (library—statistics—weekly/monthly well activity), attached hereto as Exhibit 39.

from serious ozone pollution.[76] This pollution is taking a toll on residents of San Juan County. The New Mexico Department of Public Health has documented increased emergency room visits associated with high ozone levels in the County.[77]

Air quality in national parks and wilderness areas is also suffering as a result of oil and gas development. Researchers have determined that numerous "Class I areas" – a designation reserved for national parks, wilderness areas, and other such lands[78] – are likely to be impacted by increased ozone pollution as a result of oil and gas development in the Rocky Mountain region, including Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.[79] These areas are all near concentrated oil and gas development in the San Juan Basin.[80]

As oil and gas development moves into new areas, particularly as a result of the boom in development of shale resources, ozone problems are likely to follow. For example, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone NAAQS.[81] Experts also anticipate air quality problems associated with development of the Marcellus shale in the Mid-Atlantic region.[82]

Sulfur dioxide: Sulfur dioxide causes respiratory problems, including increased asthma symptoms. Short-term exposure to sulfur dioxide has been linked to increased emergency room visits and hospital admissions. Sulfur dioxide reacts in the atmosphere to form particulate matter (PM), an air pollutant which causes a great deal of harm to human health.[83] PM is discussed separately below.

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[76] *See Four Corners Air Quality Task Force Report of Mitigation Options*, at vii (Nov. 1, 2007), *available at* http://www.nmenv.state.nm.us/aqb/4C/TaskForceReport.html, attached hereto as Exhibit 40.

[77] Myers *et al.*, *The Association Between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County* (Aug. 2007), *available at* http://www.nmenv.state.nm.us/aqb/4c/Documents/SanJuanAsthmaDocBW.pdf, attached hereto as Exhibit 41.

[78] *See* 42 U.S.C. § 7472(a).

[79] Rodriguez et al., *Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States*, 59 Journal of the Air and Waste Management Association 111 (Sept. 2009), available at http://www.wrapair.org/forums/amc/meetings/091111_Nox/Rodriguez_et_al_OandG_Impacts_JAWMA9_09.pdf, attached hereto as Exhibit 42.

[80] *Id.* at 1112.

[81] *See* Kemball-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale* 44 Environ. Sci. Technol. 9357, 9362 (Nov. 18, 2010), attached hereto as Exhibit 43.

[82] Elizabeth Shogren, *Air Quality Concerns Threaten Natural Gas's Image*, National Public Radio (June 21, 2011), *available at* http://www.npr.org/2011/06/21/137197991/air-quality-concerns-threaten-natural-gas-image, attached hereto as Exhibit 44.

[83] EPA, Sulfur Dioxide, Health, *available at* http://www.epa.gov/air/sulfurdioxide/health.html, attached hereto as Exhibit 45.

The primary source of sulfur dioxide from the oil and gas industry is natural gas processing plants.[84] Sulfur dioxide is released as part of the sweetening process, which removes hydrogen sulfide from the gas.[85] Sulfur dioxide is also created when gas containing hydrogen sulfide (discussed below) is combusted in boilers or heaters.[86]

Hydrogen sulfide: Hydrogen sulfide is an air pollutant with toxic properties that smells like rotten eggs and can lead to neurological impairment or death. Long-term exposure to hydrogen sulfide is linked to respiratory infections, eye, nose, and throat irritation, breathlessness, nausea, dizziness, confusion, and headaches.[87] Although hydrogen sulfide was originally included in the Clean Air Act's list of hazardous air pollutants, it was removed with industry support.[88]

Some natural gas contains hydrogen sulfide. When hydrogen sulfide levels are above a specific threshold, gas is classified as "sour gas."[89] According to EPA, there are 14 major areas in the U.S., found in 20 different states, where natural gas tends to be sour.[90] All told, between 15 and 20% of the natural gas in the U.S. may contain hydrogen sulfide.[91]

Given the large amount of drilling in areas with sour gas, EPA has concluded that the potential for hydrogen sulfide emissions from the oil and gas industry is "significant."[92] Hydrogen sulfide may be emitted during all stages of development, including exploration, extraction, treatment and storage, transportation, and refining.[93] For

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[84] 76 Fed. Reg. at 52,756.
[85] TSD 3-3 to 3-5.
[86] 76 Fed. Reg. at 52,756.
[87] EPA, Office of Air Quality Planning and Standards, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas* (EPA-453/R-93-045), at i (Oct. 1993) (hereinafter "EPA Hydrogen Sulfide Report"); *available at* http://nepis.epa.gov/Exe/ZyNET.exe/00002WG3.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1991+Thru+1994&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C91thru94%5CTxt%5C00000006%5C00002WG3.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p%7Cf&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL, attached hereto as Exhibit 46.
[88] *See* Pub. L. 102-187 (Dec. 4, 1991), attached hereto as Exhibit 47. We do not concede that this approval was appropriate. Hydrogen sulfide meets section 112 of the Clean Air Act's standards for listing as a hazardous air pollutant, and should be so regulated. However, until such time as it is reinstated as an HAP, it must be included in the revised NSPS.
[89] 76 Fed. Reg. at 52,756; RIA at 2-3. Gas is considered "sour" of hydrogen sulfide concentration is greater than 0.25 grain per 100 standard cubic feet, along with the presence of carbon dioxide. *Id.*
[90] *EPA Hydrogen Sulfide Report* at ii.
[91] Lana Skrtic, *Hydrogen Sulfide, Oil and Gas, and People's Health* ("Skrtic Report"), at 6 (May 2006), *available at* http://www.earthworksaction.org/pubs/hydrogensulfide_oilgas_health.pdf, attached hereto as Exhibit 48.
[92] *EPA Hydrogen Sulfide R*eport at III-35.
[93] *Id.* at ii.

example, hydrogen sulfide is emitted as a result of leaks from processing systems and from wellheads in sour gas fields.[94]

Hydrogen sulfide emissions from the oil and gas industry are concerning because this pollutant may be harmful even at low concentrations.[95] Although direct monitoring of hydrogen sulfide around oil and gas sources is limited, there is evidence that these emissions may be substantial, and have a serious impact on people's health. For example, North Dakota reported 3,300 violations of an odor-based hydrogen sulfide standard around drilling wells.[96] People in northwest New Mexico and western Colorado living near gas wells have long complained of strong odors, including but not limited to hydrogen sulfide's distinctive rotten egg smell. Residents have also experienced nose, throat and eye irritation, headaches, nose bleeds, and dizziness.[97] An air sample taken by a community monitor at one family's home in western Colorado in January 2011 contained levels of hydrogen sulfide concentrations 185 times higher than safe levels.[98]

Particulate Matter (PM): PM consists of tiny particles of a range of sizes suspended in air. Small particles pose the greatest health risk. These small particles include "inhalable coarse particles," which are smaller than 10 micrometers in diameter (PM_{10}), and "fine particles" which are less than 2.5 micrometers in diameter ($PM_{2.5}$). PM_{10} is primarily formed from crushing, grinding or abrasion of surfaces. $PM_{2.5}$ is primarily formed by incomplete combustion of fuels or through secondary formation in the atmosphere.[99]

PM causes a wide variety of health and environmental impacts. PM has been linked to respiratory and cardiovascular problems, including coughing, painful breathing, aggravated asthma attacks, chronic bronchitis, decreased lung function, heart attacks, and premature death. Sensitive populations, include the elderly, children, and people with existing heart or lung problems, are most at risk from PM pollution.[100] PM also reduces visibility,[101] and may damage important cultural resources.[102] Black carbon, a

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[94] TSD at 2-3.

[95] *See* James Collins & David Lewis, *Report to CARB, Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protections of Children* (Sept. 1, 2000), *available at* http://oehha.ca.gov/air/pdf/oehhah2s.pdf, attached hereto as Exhibit 49.

[96] EPA Hydrogen Sulfide Report at III-35.

[97] *See* Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development*, at 11-14 (July 2011), attached hereto as Exhibit 50.

[98] *Id.* at 21.

[99] *See* EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html, attached hereto as Exhibit 51; BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Final Environmental Impact Statement* ("West Tavaputs FEIS"), at 3-19 (July 2010), *available at* http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html, attached hereto as Exhibit 52.

[100] RIA at 4-19; EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html

[101] EPA "Visibility – Basic Information" http://www.epa.gov/visibility/what.html, attached hereto as Exhibit 53.

[102] *See* EPA, Particulate Matter, Health West Tavaputs EIS, at 3-19; RIA at 4-24.

component of PM emitted by combustion sources such as flares and older diesel engines, also warms the climate and thus contributes to climate change.[103]

The oil and gas industry is a major source of PM pollution. This pollution is generated by heavy equipment used to move and level earth during well pad and road construction. Vehicles also generate fugitive dust by traveling on access roads during drilling, completion, and production activities.[104] Diesel engines used in drilling rigs and at compressor stations are also large sources of fine PM/diesel soot emissions. VOCs are also a precursor to formation of $PM_{2.5}$.[105]

PM emissions from the oil and gas industry are leading to significant pollution problems. For example, monitors in Uintah County and Duchesne County, Utah have repeatedly measured wintertime $PM_{2.5}$ concentrations above federal standards.[106] These elevated levels of $PM_{2.}$ have been linked to oil and gas activities in the Uinta Basin.[107] West Tavaputs FEIS at 3-20. Modeling also shows that road traffic associated with energy development is pushing PM_{10} levels very close to violating NAAQS standards.[108]

3. EPA must revise and expand the existing performance standards to curb this pollution

The current NSPS is inadequate and outdated. In 1985, EPA promulgated two separate NSPS for the "crude oil and natural gas production" sector.[109] The first NSPS addresses leaks of VOCs from onshore natural gas processing plants.[110] The second regulates sulfur dioxide emissions from natural gas processing plants.[111] The two standards only address emissions from natural gas processing plants, leaving the majority of emissions from the oil and gas industry unregulated at the federal level.

As we discuss above, EPA is required under Section 111 of the Clean Air Act to "review and, if appropriate, revise" NSPS standards every 8 years.[112] Although more than 25 years have passed since EPA promulgated the NSPS for the oil and natural gas sector, EPA has not reviewed or updated the standard until now.

Not only are the existing performance standards for this industry inadequate, but existing state regulations do not fill the gaps. As we describe below, some states do

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[103] UNEP Report at 6; IPCC (2007) at Section 2.4.4.3.
[104] *See* BLM, GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement, at App. J at 2 (Oct. 2010) ("GASCO DEIS")
[105] RIA at 4-18.
[106] GASCO DEIS at 3-12.
[107] West Tavaputs FEIS, at 3-20 (July 2010).
[108] *See* GASCO DEIS at 4-27.
[109] 76 Fed. Reg. at 52,741.
[110] 40 C.F.R. Part 60, Subpart KKK.
[111] 40 C.F.R. Part 60, Subpart LLL.
[112] 42 U.S.C. § 7411(b)(1)(B).

regulate this industry with some rigor (indeed, in a few cases, state rules are more rigorous than EPA's proposed standards), but these regulations are not uniform across the states, nor comprehensive. Eastern states, newly contending with the shale gas boom, are particularly in need of the federal baseline the NSPS must provide, as most of these states do not have adequate air quality rules specific to oil and gas production. Pennsylvania, for instance, does not have regulations that would require reduced emission completions, even though wellhead emissions are primary pollution sources for the industry. To our knowledge, other Marcellus Shale states, including Ohio, New York, and West Virginia likewise lack comprehensive modern air rules to regulate the industry's air quality impacts. EPA rulemaking is thus urgently needed.

Moreover, as EPA's proposed rule demonstrates, there are numerous cost-effective control technologies available to control emissions from this sector, that can and must form the basis for updated performance standards.

II. TECHNICAL REVIEW OF EPA's PROPOSED STANDARDS

As we discuss below, the record before EPA demonstrates that EPA must maintain the stringency of its proposed standards, and in some respects must strengthen them, to comply with the Clean Air Act's rigorous requirements. The proposed standards are based upon practices that are already widespread in the industry, and generally save the industry money by allowing it to capture additional valuable natural gas. By requiring existing industry best practices for many sources, and codifying those practices into law, EPA does not always meet the Act's requirement to force additional control technology innovation. Indeed, the Agency is in several instances not even providing incentives for the development of new control techniques but instead merely bases standards on long-demonstrated and cost-effective systems of emission reduction. For that reason, the proposed standards are in some cases more technology-following than technology-forcing, and are thus unlawfully lenient.

The agency therefore must correct several significant weaknesses in the rules. These flaws fall into several categories. In some instances, the proposed standards are vague and/or unclear. In others, the agency has created unnecessarily broad exemptions to its standards which will allow operators to escape compliance, or which will cause enforcement difficulties. In some other instances, EPA has set standards below the levels which industry can achieve, and must therefore tighten its control standards. Finally, EPA has simply failed to set standards for some sources and facility types at all.

Our review below relies in part on several reports by well-recognized experts, which we incorporate in full by reference. These experts include Dr. Ranajit Sahu, whose report focuses on the engineering data underlying EPA's proposal, Cindy Copeland and Megan Williams, whose report addresses methane and VOC control technologies, Dr. Laurie

Johnson, whose report concerns issues of methane valuation,[113] and Rick Hornby and Dr. Carl Swanson, whose report concerns natural gas pricing.

A. Wellhead Facilities

1. EPA's Proposal

EPA proposes to regulate "gas wellhead facilities," each of which would constitute a "single natural gas well."[114] EPA determined that it was not feasible to set a standard of performance for this category because some pollutants would be emitted in a mixture of water and sand, apparently in ways that would render them impossible to properly channel or measure, *cf.* 42 U.S.C. § 7411(h)(2). It therefore promulgated operational standards, pursuant to section 111(h).[115]

These standards would require, for "each well completion operation with hydraulic fracturing," that the operator conduct "reduced emission" or "green" completions, under which the owner or operator is required to "minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system."[116] Operators would have to use sand traps, vessels, tanks, and separators to "safely maximize resource recovery and minimize releases to the environment" and route all salable gas to a gathering line "as soon as practicable." *Id.* Flowback emissions would be sent to a gathering line "except in conditions that may result in a fire hazard or explosion."[117] Where such conditions exist, operators are to use "[c]ompletion combustion devices . . . equipped with a reliable continuous ignition source."[118]

Two types of wells, "wildcat" and "delineation" wells, may avoid using gathering lines and instead "reduce emissions . . . using a completion combustion device."[119] A wildcat well is "a well outside known fields or the first well drilled in an oil or gas field where no other gas or oil production exists."[120] A delineation well is "a well drilled in order to determine the boundary of a field or producing reservoir."[121]

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[113] Dr. Laurie Johnson, Ph.D, "Comments on The Social Benefits of Methane Reductions from the Proposed Oil and Gas New Source Performance Standards," *Natural Resources Defense Council*, November 17, 2011, attached hereto as Exhibit 249.
[114] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5365(a)). Proposed 40 C.F.R. § 60.5365(a) is missing a "which" in the sentence explaining that a gas wellhead facility is a single natural gas well. EPA must correct this error.
[115] *See* 76 Fed. Reg. at 52,758-59.
[116] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)).
[117] *Id.*
[118] *Id.*
[119] *Id.* (Proposed 40 C.F.R. § 60.5375(f)).
[120] *Id*. at 52,811 (Proposed 40 C.F.R. § 60.5430).
[121] *Id.* at 52,809.

2. BTSER Determination

a. New Wellhead Facilities

We agree with EPA that some form of reduced emissions completion (REC) constitutes the "best technological system of continuous emission reduction" (BTSER) which has been adequately demonstrated for wellhead facilities,[122] and that emissions standards based on these practices would "reflect the best system of emission reduction . . . adequately demonstrated."[123] We emphatically do not agree, however, that EPA has, in fact, drafted regulations compliant with the BTSER standard. As we discuss below, EPA's proposed regulations have such significant flaws—including impermissible exemptions – that they will not be compliant with section 111 without significant revision.

As the Sahu and Copeland and Williams reports discuss, the record amply supports the broad utility and cost-effectiveness of REC techniques.[124] Furthermore, as EPA explains in the Technical Support Document for this rulemaking (TSD), REC "not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented."[125] EPA estimates that an average green completion results in net *savings* of $5,697 and yield 20.8 tons of avoided VOC emissions per well.[126] In fact, the savings will be even higher because, as we discuss below,[127] EPA underestimated the direct financial benefits of RECs by using an unrealistically low gas price and potentially overstating REC costs.

In light of the practice's financial benefits, industry has widely adopted REC, and several states currently require REC. Colorado, for instance requires "green completion practices" wherever technically and economically feasible,[128] and Wyoming requires green completions in its Jonah Anticline fields and all "Areas of Concentrated Development."[129] According to EPA, "RECs have become a popular practice among Natural Gas STAR production partners," with, as of 2010, thirteen different partners

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[122] *See* 76 Fed. Reg. at 52,758-59, 42 U.S.C. § 7411(h)(1)
[123] 42 U.S.C. § 7411(a)(1).
[124] Cindy Copeland and Megan Williams, *Methane Related Comments on EPA's "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," Proposed Rule* (November 29, 2011*)* attached hereto as Exhibit 54; Dr. Ranajit Sahu, *Comments on EPA Proposed NSPS Rulemaking for Crude Oil and Natural Gas Production, Transmission, and Distribution* (Nov. 2011)at 9-11, attached hereto as Exhibit 55.
[125] TSD at 4-12.
[126] TSD at 4-16 – 4-18.
[127] *See infra* Section VII.
[128] Co. Oil & Gas Conserv. Comm'n ("COGCC") Rule 805(b)(3)(A), attached hereto as Exhibit 56.
[129] Wy. Oil and Gas Production Facilities Permitting Guidance ("Wy. Guidance") at 15, 20, attached hereto as Exhibit 57.

reporting success.[130] EPA Natural Gas Star partners have reported considerable success with REC in a variety of geographical contexts, including:

- BP's implementation of RECs on 106 wells, at both high and low pressures, in the Green River Basin of Wyoming, which resulted in a "conservative" value of gas saved at $20,000 per well.[131]

- Noble Experience's implementation of REC on 10 hydrofractured wells in Oklahoma, with profits of $340,000.[132]

- An anonymous partner company's implementation of REC on 30 wells in Fort Worth, Texas, which resulted in a "conservative" savings of $50,000 per well.[133]

- Anadarko's implementation of REC in the Denver-Julesberg Basin of Wyoming, saving an average of $19,369 per well.[134]

- Chesapeake and Devon's extensive use of green completions in the Barnett Shale (these companies are the two largest producers in the Barnett Shale), constituting 114 of every 115 wells, and 85% of wells, respectively.[135]

We discuss further examples of profitable RECs in our cost discussion below,[136] and industry and EPA literature is replete with examples of successful RECs.[137]

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[130] EPA, *Reduced Emissions Completions: Lessons Learned from Natural Gas STAR Partners* at 1 (2010), available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, attached hereto as Exhibit 58. *See also* EPA, *Reducing Methane Emissions During Completion Operations* (Oct. 24, 2006), attached hereto as Exhibit 59.
[131] *Id.* at 10.
[132] *Id.*
[133] *Id.* at 10.
[134] Anadarko, *Reduced Emission Completions in DJ Basin and Natural Buttes*, EPA Producers Technology Transfer Workshop (May 1, 2008), attached hereto as Exhibit 60.
[135] April 18, 2011 presentation to the Oil and Gas Task Force of the North Texas Clean Air Steering Committee; available at http://www.nctcog.org/trans/committees/ntcasc/OGTF/041811/Items3BC.pdf, attached hereto as Exhibit 61.
[136] *See infra* Section VII(B)(2)(a).
[137] *See, e.g.*, Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, *Reduced Emission Completions/Plunger Lift and Smart Automation* (Jan. 28, 2009) (collecting examples of profitable RECs), attached hereto as Exhibit 62; EPA, PRO Fact Sheet 703, *Green Completions* (documenting use of RECs by BP & ConocoPhilips), attached hereto as Exhibit 63; EPA, Natural Gas STAR Lessons Learned, *Reduced Emissions Completions* (endorsing RECs as a profitable and effective control technique); John Corra, Director, Wyoming Department of Environmental Quality, *Emissions from Hydrofracking Operations and General Oversight Information for Wyoming* (July 13, 2011) (describing successful implementation of state-level REC requirement), attached hereto as Exhibit 64; Chesapeake Energy, *Air Emissions and Regulations*(July 2011) (stating that Chesapeake uses green completions at its wells), attached hereto as Exhibit 65;Chesapeake Energy, *Greenhouse Gas Emissions* (last visited Nov. 2011) (stating that "green completions . . . have been Chesapeake's largest contributor of emissions

In short, RECs generate profits, reduce emissions, and allow for more salable gas and condensate. RECs therefore are the *minimum* requirement for BTSER for new and modified wells. No lesser requirement would be compliant with section 111. Yet, in several regards, EPA has failed to impose this level of control, as we will shortly discuss.

b. Modifications

We also support EPA's recognition that recompletions of fractured or refractured wells drilled prior to August 23, 2011 constitute modification under section 111(a). These activities are a very large source of emissions, and their control under the proposed standards of performance is a key component of EPA's proposal. There is a definitional flaw in EPA's proposed language, however, which we discuss below.

Under part 60, subpart OOOO, 40 C.F.R. § 60.5430, EPA sets forth the following regarding modifications in the oil and gas sector:

> any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. *For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification*.[138]

This provision, to the extent that it defines hydraulic fracturing operations as modifications, is in keeping with section 111's definition of modification. But EPA must modify it in two regards. First, it must make pellucidly clear that EPA intends to override any conflicting regulatory definitions of modification. Second, it must revise the definition to remove undefined terms.

First, The Clean Air Act defines "modification" under section 111 as "*any* physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."[139] As EPA points out, during the fracturing or refracturing of an existing well, "physical change occurs to the existing well, which includes the wellbore, casing and tubing, resulting in an emissions increase during the

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reductions), attached hereto as Exhibit 66; EnCana, *Environment Health and Safety Commitment* (describing EnCana's efforts to reduce flaring and venting at its wells), attached hereto as Exhibit 67.

[138] 76 Fed. Reg. at 52,810 (emphasis added).

[139] 42 U.S.C. § 7411(a)(4) (emphasis added); *see also* 40 C.F.R. § 60.14(a) ("any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act.").

completion operation."[140] For purposes of NSPS, an emissions increase occurs whenever emissions after a physical change are greater than emissions immediately prior to the change.[141]

Not only do hydraulic fracturing activities meet the statutory definition of modification, but EPA's proposal in proposed 40 C.F.R. § 60.5430 that recompletions of these wells are modifications for the purposes of this industry overrides any conflicting provisions in the general NSPS definition of modification contained in 40 C.F.R. § 60.14.[142] Thus, to the extent that any of the exemptions contained in 60.14(c) would otherwise prevent recompletions and refracturing from being considered modifications, they would be overridden by the specific oil and gas provision.

While the proposed 60.5430 is sufficient to override any conflicting portions of 60.14,[143] we encourage EPA to clarify the regulatory language by explicitly invoking § 60.14(f) and explaining that the capital expenditure test codified at 40 C.F.R. § 60.14(e)(2), for example, does not apply.[144]

Second, EPA is wrong to define a modification in this context as "each recompletion of a fractured or refractured existing gas well" because "recompletion" is an undefined term and so will lead to confusion. The relevant modification – and source of increased emissions – in this context is, in fact, the hydraulic fracturing operation at the well. EPA must simply say so.

So the revised section 60.5430 would read:

> *Modification* means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. *For the purposes of this subpart, each hydraulic fracturing operation at an existing gas well is considered to be a modification regardless of any provision of 40 C.F.R. § 60.14(e) stating regulatory exemptions to the term "modification*.

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[140] 76 Fed. Reg. at 52,759; *see also* TSD at 4-1 – 4-2.

[141] *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 910, 915 (7th Cir. 1990) (citing CAA § 111(a) and 40 C.F.R. § 60.14(b)(2)), attached hereto as Exhibit 68.

[142] *See id*. § 60.14(f). EPA previously has relied on 60.14(f) to depart from its general regulatory definition of modification by delineating what constitutes a modification under a sector-specific subpart of the NSPS "to eliminate ambiguity." *See* 73 Fed. Reg. 35838, 38856 (June 24, 2008) (defining what constitutes a flare modification for Petroleum Refineries, subpart Ja), (codified at 40 C.F.R. § 60.100a(c) (2010)).

[143] We do not concede that EPA' regulatorily-created "exemptions" from the statute's broad modification definition are legal.

[144] *See also* 40 C.F.R. § 60.2 (defining "capital expenditure").

3. Further Critiques

We support EPA's proposal to require "reduced emission" or "green" completions. Nonetheless, there are three general areas in which the proposal must be strengthened. EPA must at a minimum (1) clarify and strengthen the language of the proposed standard; (2) extend the REC requirement to many well types that are currently excluded from the proposed standard; and (3) enhance standards for pit flaring.

a. Definitional Issues

The proposed regulation uses a number of undefined or poorly defined terms. As a result of the needlessly complicated wording, the proposed regulatory text fails in three regards. It fails to clearly and inclusively define hydraulically fracturing. It fails to clearly apply EPA's standards to fractured and refractured existing wells. And it fails to articulate comprehensible and enforceable standards. EPA must correct these failings. As EPA has explained in the context of permit requirements, source obligations must be practically enforceable, and language that is vague, ambiguous, or otherwise unclear creates lack of clarity as to legal obligations. The same concern obviously attaches to the underlying regulations as well.

First, EPA's core "hydraulic fracturing" definition must be revised. EPA's proposal defines the process as:

> The process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers.[145]

The definition is unclear, which will lead to enforcement problems, and may also be underinclusive. EPA must revise it.

The lack of clarity arises in two ways. First, EPA defines fracturing as involving a "high" rate of "extended" back flow. These are relative terms, and are not defined in the text. Operators and enforcement staff are highly likely to differ over what constitutes high or extended flows.

The second clarity problem arises because the definition states that the process takes place by directing chemicals "to penetrate [various formations] that involve high rate, extended back flow *to expel fracture fluids and sand during completions and well workovers*." By focusing on the *purpose* of the activity, rather than its effects, EPA has inadvertently left room for debate as to whether a given well operation is intended "to penetrate" formations or has some other goal. Worse, the proposed text muddles the

[145] 76 Fed. Reg. at 52,810. (Proposed 40 C.F.R. § 60.5430).

purpose at issue, as it refers both to processes intended "to penetrate" formations and "to expel fracture fluids and sand during completions and well workovers." This second "purpose" is not a goal of fracturing operations, because backflow is not intended to do anything in particular; it is a *consequence* of pressure in the well itself caused by the fracturing process (which itself is not intended "to expel fracture fluids and sand").

EPA can, and must, resolve all of these problems by revising the definition to avoid discussions of the magnitude of backflow and the purpose of the operation. It can do so because all hydraulic fracturing, as far as we are able to determine, involves perforating the casing of the well with explosive charges to allow fracturing fluids to enter a formation. EPA can therefore use the moment of casing perforation as the trigger point for NSPS applicability.

The underinclusivity problem, next, arises because fracturing may not always be conducted with water. Fracturing using foams,[146] gases, [147] or hydrocarbons[148,149] is also possible, and foam fracturing is used in U.S. plays. Although these methods may result in less immediate flowback, they may still generate significant produced water, which is a source of VOCs and methane, and may also result in increased emissions, relative to conventional wells, during the hydraulic fracturing process. EPA must investigate whether emissions from these processes are significant. If so, it must modify its definition to refer to these processes as well, or, to encompass other potential processes, could also refer simply to "pressurized substances," which "may" include water.

The fully corrected definition would, in other words, read:

> The process of directing pressurized substances, which may contain foam, gases, water, hydrocarbons, proppant, and any added chemicals, into a well whose casing is perforated, allowing these substances to leave the well bore.

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[146] *See, e.g.*, EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (2004) at 4-5 – 4-6 (discussing these foam gels), attached hereto as Exhibit 69; Ken Little, Knoxville News, "Nitrogen-heavy gas drilling method common in Tenn." (Dec. 5, 2010), available at http://www.knoxnews.com/news/2010/dec/05/nitrogen-heavy-method-prevalent-in-tenn/?print=1, attached hereto as Exhibit 248.

[147] 76 Fed. Reg. at 52,757.

[148] *See, e.g.*, Hans. D. Linhardt, "LNG and LIN can be Alternative Fracturing Methods for Shale Gas" (Dec. 18, 2009), available at https://www.gplus.com/natural-resources/insight/lng-and-lin-can-be-alternative-fracturing-methods-for-shale-gas-45488, attached hereto as Exhibit 70.

[149] *See, e.g.*, Anna Driver, Reuters, "Propane Substitutes for water in shale fracking" (Nov. 22, 2011), available at http://www.reuters.com/article/2011/11/22/us-shale-propane-idUSTRE7AL1ML20111122, attached hereto as Exhibit 71.

Second, as we have indicated above, EPA's proposed language does not effectuate its intent to apply its standards to "completions associated with fracturing or re-fracturing of existing gas wells."[150]

We have already explained why EPA's definition of "modification" must be revised to refer simply to "hydraulic fracturing operations" at existing wells. EPA must also address a second definitional problem, which is that its proposed applicability language for its REC standard would attach that requirement to "each well completion operation with hydraulic fracturing."[151] This language does not clearly refer to fracturing and refracturing at *existing wells*. Stepping through the definitions, a "well completion operation means any well completion or well workover occurring at a gas wellhead affected facility."[152] A well "completion," next, is defined with reference to "newly drilled" wells, so EPA must have intended the "workover" term to encompass refracturing as a modification at existing wells. Indeed, the only explicit discussion of well modifications in the proposed regulation is the statement that a "workover" is a modification. [153] But the workover term itself is not defined, and is vague.[154] The result is that EPA has not clearly applied REC requirements to fracturing and refracturing at existing wells. [155]

A far simpler and more effective solution, which we urge EPA to adopt, is to amend proposed 40 C.F.R. § 60.5375 to impose REC and associated requirements on each "well completion, and any other hydraulic fracturing operation," using the fracturing of the well casing itself as the trigger point to apply standards, and as the indicator that a "modification" has occurred. With this definitional change, coupled with the revisions to the modification section we discuss above (which would make clear that each fracturing event is a modification), such operations at existing wells will be covered by the standards, as they must be.

Third, the proposed standard itself is dangerously unclear. EPA's proposed standard requires operators to "minimize" emissions by storing and then routing to pipelines as much recovered liquid and gas as possible, with the backstop of flaring or venting the remaining emissions, and to "minimize" releases to the environment.[156] But it does not define what "minimize" means, or how EPA will know when an operator is not "minimizing" in accordance with the standard. Likewise, though EPA provides that

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[150] 76 Fed. Reg. at 52,745-46.
[151] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. §60.5375).
[152] 76 Fed. Reg. at 52,809 (Proposed 40 C.F.R. § 60.5430).
[153] As we discuss above, EPA should clarify that by refracturing, recompletion or workover is a modification pursuant to CAA § 111(a) *per se*, such that the capital expenditure test adopted by EPA at 40 C.F.R. § 60.14(e)(2) does not apply. *See also* § 60.2 (defining "capital expenditure"), § 60.14(f) (EPA may adopt "special provisions" under part 60 that supercede the general provisions of § 60.14).
[154]
[155] We note that EPA's "hydraulic fracturing" definition also uses the undefined "workover" term. EPA must strike that term there as well, if it does not define it.
[156] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)).

resource recovery is to be "safely maximize[d]," it does not define that term either. Nor does EPA set any limit on how much gas may be flared, rather than captured, stating only that gas which "cannot be directed" to a gathering line is to be sent to flares. Similarly, salable gas is to be routed to a gathering line as "soon as practicable," a term that leaves considerable room for dispute. EPA must tighten these definitional holes.

EPA must resolve these problems by stating clearly that, except in the very narrow defined circumstances where safety considerations so warrant, *all* emissions from the wellhead must be either captured or flared, not vented, and that flaring is a disfavored secondary option, to be used only when it is not possible to capture the wellhead emissions for safety reasons. In doing so, EPA must avoid the use of the "maximize" and "minimize" terms which will otherwise cause substantial difficulties.

It must do so by revising proposed 40 C.F.R. § 60.5375(a) to read as follows, in pertinent part[157]:

> … (1) You must capture all gases and liquids emanating from each well subject to these regulations at all times following perforation of the well casing until flowback has ceased.
>
> (2) You must route all recovered liquids into storage vessels and route all recovered gas into a gas gathering line or collection system, except as specified in paragraph (a)(3).
>
> (3) Where direction of recovered gases or liquids into storage vessels or gas gathering lines is not possible due to material safety hazards, you must direct these materials to a completion combustion device, except in conditions that pose a material risk of fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

EPA must also add a requirement that operators record a specific reason for flaring or venting in lieu of capture, to the record-keeping requirements in the proposed rule, and provide advance notice of flaring or venting to permitting authorities where feasible.[158]

Finally, EPA must clarify the proposed regulation to reflect EPA's intention as stated in the preamble that the Administrator must be notified *before* well completions occur. The preamble states that "the proposed NSPS requires 30-day *advance* notification of each completion or recompletion of a hydraulically fractured gas well."[159] The proposed regulation, however, merely states that an operator must "notif[y] the Administrator within 30 days of the commencement of the well completion operation."[160] Read

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[157] We recommend putting paragraph (a)(2) in the proposal before paragraph (a)(1), and have done so here, because (a)(2) describes how operators must recover the "recovered liquids" and "recovered gas" referred to in (a)(1).

[158] *See* 76 Fed. Reg. at 52,808 (Proposed 40 C.F.R. § 60.5420(c)(1)(iii)(A)).

[159] *Id.* at 52,749.

[160] *Id.* at 52,805 (Proposed 60 C.F.R. § 60.5410(a)(1)).

literally, the proposed regulation would be satisfied so long as the Administrator was notified no later than 30 days *after* the completion. EPA further requests comment regarding a two day follow-up notification.[161] We agree that if the 30-day advance notification does not commit the operator to a precise date for completion, once the date is determined, then follow-up notification (at least two days prior to commencement of completion operations) must be required, to allow for on-site inspection.

b. Exclusions

EPA has improperly excluded several classes of wells that can contribute to harmful levels of air pollution.

First, EPA proposes to exempt "wildcat" and "delineation" wells from the REC requirements (but not from the flaring standards) even when they are hydraulically fractured high flowback gas wells in tight sand or shale formations. The proposed regulations define a "wildcat well" as "a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."[162] A "delineation well" is "a well drilled in order to determine the boundary of a field or producing reservoir."[163] EPA asserts without support that "[b]ecause these types of wells generally are not in proximity to existing gathering lines, REC is not an option, since there is no infrastructure in place to get the recovered gas to market or further processing."[164]

EPA does not support its conclusion and the exemptions unnecessarily and impermissibly allows excess emissions. Moreover, the exclusion invites enforcement difficulties, as operators and enforcement staff may dispute whether a well fits into either category, as the precise boundaries of a field – and the purpose for which a well is drilled – may be unclear.

To avoid these difficulties, and to extend the REC standards to as many wells as possible, EPA must eliminate its "delineation" well exemption, and sharply narrow its "wildcat" well exemption.

The "delineation" well concept is readily subject to misuse, as it turns on both the operators intent (e.g., was the well drilled "to determine" a boundary?), and upon the "boundary of a field or producing reservoir," which is a difficult and subjective line to draw. In a sense, each well drilled in a given field helps define that field's boundaries and extent, opening this exemption to confusion and gamesmanship. EPA must eliminate it.

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[161] *Id.* at 52,749.
[162] *Id.* at 52,811 (Proposed 40 C.F.R. § 60.5430).
[163] *Id.* at 52,809.
[164] 76 Fed. Reg. at 52,759.

In doing so, EPA will be following the lead of the state of Wyoming, which has determined that, in areas covered by its green completion requirements, "lack of a pipeline connection due to reasons other than wildcat, exploratory or step-out well classification" does not excuse avoiding an REC.[165] Wyoming, in other words, lacks a "delineation" well exemption – the wells which it exempts are all in remote, undeveloped areas, unlike "delineation" wells, which are drilled in existing fields.[166] Remoteness is the hallmark. As EPA's own TSD explains:

> The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[167]

EPA must follow suit. The goal must be to define a narrow, easily-recognized category of exempt wells which truly cannot construct or access a gathering line, a subset which is likely quite narrow because, as EPA acknowledges, "[i]n instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC."[168]

We urge EPA, therefore, to define wildcat well narrowly, and ensure that only wildcat wells which cannot access a gathering line receive an exemption. To do so, it must first narrow its wildcat well definition, which as proposed applies to "a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."[169] Because multiple wells may be drilled "outside known fields," and companies can and should plan to capture emissions from later wells, EPA must narrow this exemption to mean "the *first* well *drilled* outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."

Next, EPA must make clear, in Proposed 40 C.F.R. § 60.5375, that these wildcat wells can only be exempted from an REC if they are, in fact, not near a gathering line. EPA must set a reasonable distance from a gathering line below which even wildcat wells will be required to conduct an REC.

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[165] Wyoming Department of Environmental Protection, Green Completion Permit, available at: http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf, attached hereto as Exhibit 72.

[166] Wyoming, for instance, defines "wildcat" wells as "wells outside known fields or new wells which are determined by the Commission to have discovered oil or gas in a pool not previously proven productive." Wy. Oil & Gas Conserv. Comm'n Rule 1 §2(iii)., attached hereto as Exhibit 73.

[167] TSD at 4-14.

[168] *Id.*

[169] 76 Fed. Reg. at 52,809 (Proposed 40 C.F.R. § 60.5430).

EPA must consider three miles as such a reasonable distance. A typical Marcellus well, for instance, costs $3 million to drill,[170] while the costs of building a three-mile long gathering line to that well are far less, and, if the well is productive, eclipsed by the revenues the well produces.[171] If EPA deems this distance is not reasonable, it must explain why not, and propose an alternative distance.

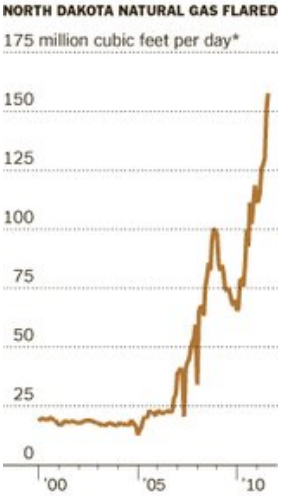
Finally, we urge EPA to collect the information necessary to determine whether all wells, including wildcat wells, can use gas that would otherwise be flared as fuel for onsite operations, and the emissions consequences of such a diversion. If onsite fuel use produces more limited secondary environmental impacts than flaring, it must be required, where possible, and may be an especially attractive option for wells that are not near a gathering line.

Second, EPA needs to include hydraulically fractured oil wells that produced associated gas in its standards. These wells are excluded under the proposed standard, which applies only to gas wells.[172] EPA acknowledges that hydraulic fracturing at oil wells creates a period of flowback with increased natural gas and VOC emissions.[173]

EPA must require that the maximum amount of gas produced from hydraulically fractured oil wells during both flowback and normal production, be captured rather than vented or flared. Recent developments raise questions about EPA's estimates of low emissions from these wells. Specifically, the *New York Times* reports that very large amounts of gas are being flared daily in the hydraulically fractured Bakken Shale play in North Dakota. The *Times* reports gas discharges of over 150 million cubic feet per day being flared in that field, as **Figure 2**, on the right of this page, indicates.[174] This huge volume of flaring is undoubtedly producing significant air pollution, and is avoidable with RECs and connection to gas gathering lines.

Flared Natural Gas

In North Dakota, much of the natural gas incidentally uncovered in the course of oil production is "flared," or burned off, and in effect, wasted. The amount of natural gas flared has risen sharply in the state.



*The difference between natural gas produced and that sold is used to represent the amount flared, although a small amount of the gas may be used in internal plant operations.

Source: North Dakota Industrial Commission, Dept. of Mineral Resources, Oil and Gas Division

This report, drawn from North Dakota government data, very strongly argues that REC, and continuing gas capture from

[170] PennState Live, *Unconventional natural gas reservoir could boost US supply* (Nov. 2008), available at http://live.psu.edu/story/28116, attached hereto as Exhibit 74.
[171] *See, e.g.*, Interstate Natural Gas Association of America, *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030* (2009) (offering pipeline cost figures) at 48, attached hereto as Exhibit 75.
[172] 76 Fed. Reg. at 52,757.
[173] 76 Fed. Reg. at 52,757, TSD §§ 4.1.1 – 4.1.2.
[174] *See* Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (Sept. 28, 2011), attached hereto as Exhibit 76.

producing oil wells, would be economically and environmentally beneficial.[175] Although producers may have to focus on expanding gathering line construction to prevent this waste, other options, including reinjection, must be explored. EPA must drive the process with a strong performance standard for such wells. As a start, EPA must require the productive capture and routing to a pipeline of vented associated gas at oil wells whenever natural gas gathering pipelines are within a reasonable distance (three miles, as we explain above) to an affected oil well. If reinjection, productive use onsite, or capture for sale of gas cannot be required, then EPA must ensure that emissions from flares are minimized.

Third, EPA is apparently considering exempting some coalbed methane wells from its REC requirement. EPA is concerned that low pressure in some coalbed methane reservoirs may present a technical barrier for performing a REC.[176] We have not found data in the record regarding the pressure in coalbed methane formations or demonstrating that these pressures render RECs infeasible. Indeed, BP has been using green completions in coalbed methane formations in the San Juan Basin for at least seven years.[177] Because RECs are possible in coalbed methane, EPA must not exempt coalbed methane wells from the NSPS's REC requirements.[178]

If EPA does, however, opt for an exemption in this area, it must ensure that the exemption is keyed specifically to the feasibility of conducting an REC at a specific coalbed methane well, and is not a blanket exemption for all such wells. Any exemption must be subject to public notice and comment.

Fourth, we are concerned that EPA has proposed no controls for other well-related activities. Liquids unloading and other well cleanup activities are dominant methane emissions sources, according to EPA's most recent greenhouse gas inventory.[179] Because VOCs are generally co-emitted with methane at natural gas production wells, we expect these activities to be significant VOC sources as well. Cost-effective technologies, including plunger lifts, are available to control these VOC emissions, and investments in such measures can be recouped within a year.[180] Yet, EPA has proposed no standards requiring these effective and widely-used measures. This decision is not consistent with EPA's obligations under section 111, as it fails to impose standards based upon an available and widely-demonstrated technology that could significantly reduce sector VOC emissions. It is our understanding that EPA believes technologies like

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[175] *See* Copeland and Williams Report at 18-20 (documenting these emissions).
[176] *See* 76 Fed. Reg. at 52,758.
[177] *See* Sahu Report at 12.
[178] *See also* Copeland and Williams Report at 15-16 (describing REC performed in Texas, Wyoming, and Colorado at low pressure well sites).
[179] US EPA (2011), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, tables A-120 (pp. A-149 – A-153), attached hereto as Exhibit 77.
[180] *See, e.g.* Sahu Report at 8, Copeland and Williams Report at 17-18.

plunger lifts are already in use at many facilities, and even a cursory investigation demonstrates that plunger lifts are, indeed, popular emissions control technology.[181]

Thus, BTSER controls must be based, at a minimum, upon plunger lifts. We note that EPA originally appears to have intended to require such activities, as "plunger lift system" is defined in the definitions section of the rule.[182] EPA must follow through. EPA must require that new wells drilled be equipped with plunger lifts or similar technology to reduce VOC emissions if they fill up with liquids. Furthermore, liquids unloading, a physical change to a gas well which substantially increases emissions of VOC from the well, must be treated as a modification of that well. This treatment is consistent with, and mandated by, EPA's recognition, in the context of hydraulic fracturing context, that such physical changes are modifications. Precisely the same legal logic applies here. EPA must therefore clarify its modification definition to include liquids unloading events, and develop standards to cover these events which, as we have demonstrated, must be based upon plunger lift technology, at a minimum.

c. Managing Flaring

EPA must also strengthen its flaring requirement. The proposed standard would channel emissions which it is not feasible to capture to a "completion combustion device, except in conditions that may result in a fire hazard or explosion."[183] These combustion devices "must be equipped with a reliable continuous ignition source over the duration of the flowback."[184] This standard is a useful start, but it does not minimize emissions risks.

First, as described above, EPA must tighten the requirements to capture gas, so it is not flared (or vented). As part of this tightening, EPA must require that operators document the reason that capture does not occur and venting *or flaring* occurs.

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[181] *See, e.g.*, Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, *Reduced Emission Completions/Plunger Lift and Smart Automation* (Jan. 28, 2009) (describing successful plunger lift projects); INGAA Foundation, *Activities to Reduce Greenhouse Gas Emissions from Natural Gas Operations* (2000) at 33 (recommending plunger lifts),attached hereto as Exhibit 78; BP, *Plunger Well Vent Reduction Project* (2006) (describing "great success" with plunger lifts), attached hereto as Exhibit 79; IPS, *Plunger Lifts* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 80; Lufkin International Lift Systems, *Plunger Lift Systems* (last visited Nov. 2011) (vendor offering plunger lift systems, attached hereto as Exhibit 81;Weatherford, *Plunger Lift System Overview* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 82; Production Lift Systems, Inc, *Plunger Lift Principles* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 83

[182] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).

[183] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)(3)).

[184] *Id.*

Second, EPA must tighten its venting exemption, which allows operators to avoid venting in conditions "that may result in a fire hazard or explosion." Safety is certainly an important consideration, but this language is vague – many conditions "may" have some degree of hazard, especially when dealing with inherently flammable gas. To avoid this problem, while retaining legitimate safety precautions, EPA must revise this passage to require combustion except in conditions "that pose a material risk of fire hazard or explosion" or similar.[185]

Third, EPA must enhance flaring requirements. The proposal allows use of a "completion combustion device," defined as "any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers."[186] EPA acknowledges that such devices will result in increased NO_x, carbon monoxide (CO) and PM emissions.[187] To our knowledge, there are no published studies on the emissions of pit flares consuming raw natural gas under field conditions. Such studies exist for refinery flares, but they may not be applicable due to the much more narrow operating conditions as opposed to pit flares. In the absence of appropriate studies, anecdotal evidence suggests that pit flares can emit significant amounts of NO_x, CO, PM (including black carbon), VOC, and methane as a result of incomplete combustion and other by-products of combustion as a whole. EPA must issue an information collection request under section 114 of the Act to gather data on this dangerous class of flares, and must also conduct field studies or sponsor field measurements of emissions from pit flares as operated in the oil and gas industry in order to quantify the public health and welfare impacts from this type of flaring.

EPA acknowledges that in practice, combustion at the wellhead is "rather crude, consisting of a horizontal pipe . . . fitted with a continuous ignition source and discharging over a pit near the wellhead."[188] This is because the flowback stream includes "periods of water, condensate and gas" that cannot be directly routed to a traditional control device.[189] EPA must minimize the use of these inefficient and polluting pit flares.

To reduce these pollutants, the proposal must require use of enclosed combustion devices where possible. In an enclosed combustion device, the flame is enclosed in a box at ground level and thus is not affected by the wind, resulting in higher combustion efficiency. An enclosed flare has many advantages including nonstructural support (ground level), straightforward erection, easy maintenance, negligible operating costs,

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[185] We have incorporated this language into our suggested revisions to Proposed 40 C.F.R. § 60.5375, above.
[186] 76 Fed. Reg. at 52, 809 (Proposed 40 C.F.R. § 60.5430).
[187] *See* 76 Fed. Reg. at 52,758; TSD at 4-20.
[188] 76 Fed. Reg. at 52,757-58.
[189] *Id.*

invisible flame, and low noise emission. The disadvantage is that they require considerable space and long interconnecting piping.

EPA also must consider the feasibility of requiring use of separators, dehydrators, and related equipment to render this stream suitable for less crude flaring devices with better pollution control characteristics.[190, 191] Such modifications would allow EPA to apply the flaring efficiency standards of 40 C.F.R. § 60.18 to field flaring operations. Although we understand that EPA is concerned that these standards may be difficult to apply to field flares as written,[192] the 98%-99% control efficiencies of well-managed flares,[193] are very likely significantly superior to the current performance of pit flares. Indeed, EPA's own methane emissions guidance documents discuss pipe flaring at well sites with 99% control efficiencies achieved through proper engineering.[194] By adding requirements to separate and dehydrate "multiphase slug flow," EPA can require well-managed flares.[195] It must do so.

B. Pneumatic Controllers

1. EPA's Proposal

EPA proposes to treat each pneumatic controller as an affected facility for NSPS purposes.[196] A "pneumatic controller" is "an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature."[197]

The proposed standard generally requires that each pneumatic controller at a natural gas processing plant "must have zero emissions of natural gas" while all other controllers "must have natural gas emissions of no greater than 6 standard cubic feet per hour."[198] There is an important exemption to this requirement. If an operator can demonstrate that "the use of a high bleed device is predicated," they will be exempt from the standards.[199] The proposal does not define "predicated."

2. BSER Determination

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[190] Sahu Report at 11-12.

[191] By adding these requirements to § 60.5375(a)(3), they would apply both to residual gas that could not be routed to a gathering line despite a REC and also in situations where a REC was infeasible.

[192] *See* TSD at 4-19.

[193] *See* Copeland & Williams Report at 21-22.

[194] EPA-600/R-96-080f, GRI-94/0257.23 June 1996 "Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary," p. 24, attached hereto as Exhibit 84.

[195] *See* 76 Fed. Reg. at 52,759; Copeland & Williams Report at 21-22.

[196] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5365).

[197] *Id*. at 52,810 (Proposed 40 C.F.R. § 60.5430).

[198] Proposed 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390).

[199] *Id*.

We generally agree with EPA that no-bleed and (where necessary) low-bleed controllers constitute BSER for this facility type. The TSD compellingly demonstrates that controllers are a major emission source, and that the cost of control for these emissions is reasonable.[200] VOC emissions from a single high-bleed controller in the production sector reach 1.92 tons per year,[201] and thousands of controllers are installed annually.[202] The incremental cost of a low-bleed controller is just $165,[203] and no-bleed instrument-air systems are also manageably inexpensive.[204] According to EPA, low-bleed controllers in the production sector alone would *save* the industry over $20 million in the first year the rule becomes effective, with increasing savings in subsequent years.[205]

We strongly support the use of this effective, inexpensive, and profitable control technology as the basis for EPA's standards.[206] However, as we discuss below, EPA's proposed regulations do not implement the statute's requirements appropriately, setting illegally high emissions limits and allowing broad exemptions from the rules. Unless EPA corrects this error, its standards will not comply with section 111's mandates.

EPA did, however, properly include each pneumatic device in the proposed NSPS as an affected facility.[207] EPA also correctly concluded that each installation of a new pneumatic device is construction subject to the NSPS.[208] This conclusion is necessary and appropriate from a policy standpoint, and fully supported as a legal matter.

EPA regulations focus on the practical ability to apply control technology to a pollution source, defining "affected facility" as "any apparatus to which a standard is applicable."[209] EPA correctly notes that a pneumatic device is an "apparatus."[210] It is also clear that each installation of a new replacement pneumatic device is construction subject to the NSPS. The regulations define "construction" as "fabrication, erection or installation of an affected facility."[211]

Furthermore, these facilities are significant sources of emissions nationwide. As EPA stated in the TSD:

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[200] *See* TSD at Ch. 5.
[201] *Id.* at 5-6
[202] *Id.* at 5-8
[203] *Id.* at 5-15
[204] *See id.* at 5-25
[205] *Id.* at 5-25.
[206] *See also* Sahu Report at 15-18 (detailing emissions rates); Copeland & Williams Report at 32-34. (documenting emissions reductions).
[207] *See* 76 Fed. Reg. at, 52,761.
[208] *Id*.
[209] 40 CFR. § 60.2.
[210] *See* 76 Fed. Reg. at 52,761.
[211] 40 CFR § 60.2 (2010).

> In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[212]

EPA estimates that a total of 17,124 new pneumatic devices will be installed each year emitting roughly 32,747 tpy of VOCs, 118,054 tpy of methane and 1,237 tpy of HAPs.[213]

It is important to note that the above figures for pneumatic devices represent only new incremental installations of that equipment. Although the proposed regulation will require that pneumatic devices installed after August 23, 2011 *as replacements of existing equipment* comply with the NSPS, the above figures do not include any estimate of the number of replacement devices or the emissions reductions that will occur as a result of their compliance with the NSPS.

3. Critiques

EPA's proposal must be improved by limiting an exemption for high-bleed devices, by extending the instances in which no-bleed devices are used, by defining "low-bleed" consistently with modern industrial practice, and by extending the standards to all pneumatic devices, including pneumatic pumps.

a. Limit The "High-Bleed" Exemption

EPA suggests that "[t]here may be situations where high-bleed controllers . . . are necessary due to functional requirements, such as positive actuation or rapid actuation."[214] It thus proposes to allow operators to "demonstrate, to the Administrator's satisfaction, that the use of a high-bleed device is predicated."[215] This demonstration "may include, but is not limited to, response time, safety and actuation."[216] This exemption is vague, will allow for excessive emissions, and is not properly enforceable.

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[212] TSD at 5-1.
[213] *See* TSD, Table 5-4 at 5-10.
[214] 76 Fed. Reg. at 52,761.
[215] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(a)),
[216] *Id.*

Initially, if EPA retains such an exemption at all, it must define the precise terms under which it can be granted. If there are particular circumstances where a particular high-bleed rate is *necessary* – not "predicated," which is an impermissibly unclear term – EPA must set out those circumstances in regulatory text, rather than providing a vague, non-exclusive list of qualities, like "safety," that any operator may cite in an attempt to avoid the standard. Instead, EPA must define particular requirements that only high-bleed controllers can meet, and require operators to prove that such circumstances are present before an exemption is granted. Unless EPA specifically defines the narrow circumstances in which it will consider allowing for excessive emissions, the exemption has the potential to overwhelm the rule.

Further, EPA must limit the upper bound of the exemption. As drafted, it allows operators to avoid *any* restrictions on the bleed rates of their high-bleed pneumatic controllers. But even the limited class of necessary high-bleed controllers must not be allowed to emit without limit. EPA must therefore draw a hard line for emissions rate above which no exemption will be granted.

EPA must also define the process by which such an exemption would be granted. It needs to specify when an operator must apply for an exemption, how it shall apply – by letter to the Administrator, for instance – how EPA will consider such requests, and how the public may be involved. The public, in particular, has a vital interest in such exemptions: Pneumatic controllers are a major source of harmful VOCs, and so directly implicate public health. Members of the public must be able to comment upon, and challenge, EPA's exemption decisions before the Environmental Appeals Board or a similar body. EPA has provided for such appeal rights in other air quality rulemakings, including in rulemakings focused solely on emissions *monitoring*.[217] Surely, such an appeal right is all the more important in rules focused upon emissions *control*.

b. Extend the Use of No-Bleed Controllers

EPA proposes to base its standard on the use of no-bleed instrument air systems only in natural gas processing plants because it believes that the electricity needed to power these systems will not be available in other settings.[218] This assumption is not supported by data in the record.

Natural gas is now produced in many developed areas, such as in Fort Worth, Texas, where significant production exists within the city borders, and southwestern Pennsylvania, in the vicinity of Pittsburgh. As a result, many pneumatic devices currently installed where electricity is readily available, and emissions of natural gas

[217] *See, e.g.*, 75 Fed. Reg. 76,060, 75,067 (Dec. 1, 2010) (revising EPA appeal provisions to allow members of the public to challenge EPA's approvals of certain greenhouse gas monitoring provisions before the Environmental Appeals Board), attached hereto as Exhibit 85

[218] 76 Fed. Reg. at 52,760.

from bleed devices, snap-acting pneumatics, and other pneumatic equipment (chemical injection pumps, etc.) are released in proximity to local populations.

EPA must set a zero-emissions standard based upon no-bleed pneumatic controllers when electricity is available within a reasonable distance, particularly when multiple devices are clustered within a single area.

For remote locations, as the Copeland and Williams report demonstrates, based upon EPA's own data, no-bleed systems are regularly being used in some instances where grid electricity is not available. Solar-powered controllers, fuel-cell powered controllers, and mechanically-controlled devices are all being used in the field. Most notably, BP reported using solar power panels to replace gas-powered devices, with a payback period of just four years.[219] Copeland and Williams also demonstrate that Colorado and Wyoming require production sector no-bleed systems, where feasible. These technologies may well constitute BSER for a broad class of production systems.

EPA must find as much and set a zero emissions standards based upon no-bleed devices wherever electricity, either from the grid or from field power sources, is available within a reasonable distance from the facility. To do so, it could structure the rule in ways parallel to its "high-bleed" exemption by establishing a rebuttable presumption that no-bleed devices must be used, except where low-bleed devices are necessary because no-bleed devices cannot feasibly be installed.

c. Properly Define "Low-Bleed"

EPA uses a 6 scf per hour bleed rate to define "low-bleed" controllers.[220] But, as the Sahu report discusses, this bleed rate, drawn from twenty-year old documents, is far higher than what modern technology can achieve in many circumstances.[221]

EPA itself states that "low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh."[222] Put differently, EPA apparently acknowledges that the *least* effective low-bleed device "on the market today" has an emission rate that is 1 scfh *lower* than the 6 scfh standard it proposes to set.

A 6 scfh standard therefore cannot constitute BSER for this facility type. We remind EPA that BSER is to be set based upon "what may be fairly projected for the regulated future, rather that the state of the art at present."[223] EPA has not even adopted a standard based upon "the state of the art at present," much less what the regulated future may hold.

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[219] *See* Copeland and Williams Report at 34-36.
[220] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(c))
[221] Sahu Report at 15-16.
[222] TSD at 5-3.
[223] *Lignite Energy Council v. U.S. EPA*, 198 F.3d at 934.

Instead, a more carefully-drawn standard is warranted. Different bleed rates among pneumatic devices correspond to different functions for those devices. As EPA recognizes, higher bleed rates may be associated with devices with shorter response times, for instance.[224] This means that controllers in some situations may be able to achieve the minimum bleed rate identified in EPA's TSD of 0.2 scfh, while some other classes of controllers may hover closer to the 5 scfh upper limit. Although *no* "low-bleed devices on the market today" has emissions of 6 scfh, according to EPA's analysis, this functional variation means that EPA must set standards by class of control device.

EPA must therefore define a maximum bleed rate for each functional class of pneumatic controller, setting each bleed rate to force technological improvements, consistent with the goals of the NSPS program. This range of allowable bleed rates must, of course, extend no higher than 5 scfh, the highest bleed rate supported in the record. For each class of controller, EPA must fully justify that its standard is no higher than the lowest emission rates that each class of controller can achieve.

Finally, we understand that some purported low-bleed pneumatics may not perform as advertised under all circumstances, or if poorly maintained. This heightens the importance of including rigorous leak detection and monitoring standards in the final rule in order to ensure that EPA captures the full benefits of its proposal.

d. Extend Control Standards to All Pneumatic Devices

EPA uses both the terms pneumatic "device" and pneumatic "controller" in the preamble, but the control standards apply only to pneumatic controllers.[225] This is a serious oversight, which EPA must correct, because the category of well-field pneumatics devices is broader than "controllers," and includes snap-acting devices, chemical injection pumps, and other devices.

In particular, pneumatic *pumps* are a significant emissions source, and those emissions can be controlled. Wyoming, for instance, requires that such pumps achieve a 98% control efficiency, or route all their emissions into closed loop systems.[226] Thus, controls which can achieve this level of reduction are not only available, but are actually in use. EPA must require them here.

In fact, EPA appears to have considered doing so, as a definition of "pneumatic pump" remains in Proposed 40 C.F.R. § 60.5430. EPA must now follow through and control this

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[224] 76 Fed. Reg. at 52,761.
[225] *See* Copeland & Williams Report at 37-38.
[226] *See id.* at 37 n. 141 (citing See Wyoming Department of Environmental Quality, Air Quality Division, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010 ("Wy. Guidance") at 9, 19.

emissions source or, at a minimum, provide a legally sufficient rationale as to why it will not do so.

Above we assert that EPA must base the standard on "zero-bleed" pneumatic *controllers* unless operators demonstrate that electricity is not feasibly available on site. In general EPA's standards should require that these other pneumatic *devices* be converted to "zero-bleed" (instrument air, electrical actuation, mechanical actuation, etc.) in conjunction with requirements for zero-bleed pneumatic controllers.

C. Compressors

1. EPA's Proposal

EPA proposes to treat each centrifugal or reciprocating compressor located between the wellhead and the city gate, except those located at the well site, as an affected facility.[227] EPA determined, for both reciprocating and centrifugal compressors, that fugitive emissions from these sources cannot be reliably measured or controlled. It therefore set a design and work practice standard under section 111(h) for these sources (and hence is bound by that section's BTSER standard, as we discuss above).[228]

EPA estimates that new centrifugal compressors at processing and transmission and storage sites, if uncontrolled, will annually emit 5,408 tons of methane, 377.9 tons of VOCs, and 13.25 tons of HAPs; non-wellhead reciprocating compressors will annually emit 8,100 tons of methane, 2,090.73 tons of VOCs, and 78.63 tons of HAPs.[229] Clearly, these emissions are significant.

Under the proposed NSPS, all new or modified centrifugal compressors must use a dry seal system upon initial startup.[230] New or modified reciprocating compressors must replace rod packing before the unit reaches 26,000 hours of operation, and units must continuously monitor hours of operation to ensure compliance with this standard.[231]

2. BTSER Determination

We generally agree that among centrifugal compressors, use of dry seals as opposed to wet seals is BTSER. Dry seals are a better option than the option to use "wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device" because of the adverse collateral impacts of flares.[232] We further

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[227] 76 Fed. Reg. at 52,799. (Proposed 40 C.F.R. § 60.5365(b)-(c)).
[228] *See* 76 Fed. Reg. at 52,762-63 (explaining these determinations); 42 U.S.C. § 111(h) (providing for such standards).
[229] TSD at 6-10.
[230] 76 Fed. Reg. at 52,800. (Proposed 40 C.F.R. § 60.5380(a)).
[231] *Id.*. at 52,800. (Proposed 40 C.F.R. § 60.5385(a)).
[232] *Id.* at 52,746.

agree that among reciprocating compressors, frequent rod packing replacement is BTSER.

We also agree that each compressor is properly considered an affected "facility," subject to EPA's proposed standards. As we explained above, each compressor is plainly an "apparatus" properly regulated under section 111, and installation of a new replacement compressor is construction subject to the NSPS because the regulations define "construction" as "fabrication, erection or installation of an affected facility."[233]

As we explain below, however, we disagree with EPA's treatment of the two compressor technologies as inherently distinct. EPA must investigate whether dry seal centrifugal compressors represent BTSER for compressors generally. If dry seal centrifugal compressors are determined to have the lowest emissions, then EPA must use that emission rate as its "achievable" emission limitation standard. Indeed, because EPA is setting "design, equipment, work practice, or operational standards,"[234] it should be able simply to require centrifugal compressors as a design standard for new installations, such that new installations of reciprocating compressors would be prohibited by the NSPS. In this event, EPA must nonetheless also promulgate a rod-packing standard, which must apply to existing reciprocating compressors that are "modified" under CAA § 111(a).

We also disagree, in several regards, with how EPA has proposed to implement its requirements. As occurs throughout the proposal, EPA has allowed for improperly broad exemptions, and impermissibly high emissions rates. It must correct these errors in order to promulgate legal final standards.

3. Critiques

a. Centrifugal Compressors

Although we support the use of dry seals as BSER, EPA must specifically require the use of "tandem" or double dry seal systems.[235]

As EPA has explained, wet seals may leak between 40-200 scf per minute (scfm), while dry seals can reduce emissions to 6 scfm or below (some EPA estimates put such leaks at just 0.5-3 scfm).[236] These replacements can pay for themselves in as little as 11 months,

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[233] 40 C.F.R. § 60.2 (2010).
[234] 42 U.S.C. § 7411(h)(1).
[235] Copeland and Williams 30-32.
[236] EPA Natural Gas STAR, *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors,* attached hereto as Exhibit 86; *see also* EPA, *Methane Savings from Compressors and VRUs* (July 27, 2006) at 12 (showing low emissions from dry seals and concluding that such seals "often used in tandem" are profitable to install in many circumstances), attached hereto as Exhibit 87.

according to EPA, and can then generate hundreds of thousands of dollars in savings annually.[237] Dry seals are readily available, and are used throughout the industry.[238]

All dry seals are not equivalent, however. Tandem seals substantially improve emissions control. According to EPA, such seals are "very effective in reducing gas leakage," as "[t]his type of seal has less than one percent of the leakage of a wet seal system vented in to the atmosphere and costs considerably less to operate."[239] Indeed, according to one prominent vendor, tandem dry seals are now "[t]he most popular configuration used in the industry."[240]

Nonetheless, EPA's proposal does not specify the use of tandem dry seals, or, indeed, even provide a definition of the "dry seal system" that EPA requires.[241] EPA must correct this error. EPA needs to require all centrifugal compressor sources to use *tandem* dry seals, and to clearly define "dry seal system" accordingly.

b. Reciprocating Compressors

For new facilities, EPA must investigate whether the NSPS should require the use of centrifugal compressors instead of reciprocating compressors as BTSER.

As a threshold issue, EPA must more thoroughly examine reciprocating compressor emissions. The data EPA has provided, however, permits the following extrapolation. EPA's posits that the average reciprocal compressor with newly installed but worn-in rod packing will leak 11.5 scfh per cylinder.[242] Other sources have indicated that reciprocating compressors with newly installed rod packing can leak as much as 60 scfh, apparently from a single cylinder.[243] EPA has also stated that a compressor with worn rod packing may leak 900 scfh from a single cylinder.[244] Although EPA did not specifically explain how much use led to this level of wear, EPA has also stated that "conventional bronze-metallic packing rings wear out and need to be replaced every 3

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[237] *See id.* at 1.
[238] *See, e.g.*, Dresser-Rand, *Dry Gas Seals* (vendor offering seals and noting that "[b]ecause of their advantages, dry gas seals are now installed on 95% of new compressors for varied service throughout the world"), attached hereto as Exhibit 88; Trem Engineering, *Mechanical Seals and Dry Gas Seals for Oil and Gas* (2010) (vendor offering dry seals and tandem dry seals), attached hereto as Exhibit 89; Globalspec, *Dry Gas Seal Configuration* (explaining how "state-of-the-art tandem gas seal designs" have become popular), attached hereto as Exhibit 90; Rolls-Royce, *Centrifugal Compressors* (describing availability of tandem dry seals in Rolls Royce designs), attached hereto as Exhibit 91.
[239] *Id.* at 4.
[240] Kaydon Ring & Seal Inc., *Dry Gas Seals* at 2. attached hereto as Exhibit 92.
[241] *See* 76 Fed. Reg. at 52,800. Proposed 40 C.F.R. § 60.5380.
[242] Copeland and Williams at 24 n.96 (citing TSD 6-12 to 6-14).
[243] Sahu Report at 20 n.80 (citing Reducing Emissions from Compressor Seals, Lessons Learned from Natural Gas Star, September 22, 2004. Available at www.epa.gov/gasstar).
[244] Natural Gas Star (2006), "Reducing Methane Emissions from Compressor Rod Packing Systems" Available at http://www.epa.gov/gasstar/tools/recommended.html, attached hereto as Exhibit 93.

to 5 years, depending on the compressor's rate of usage."[245] Absent further detail, we assume that 900 scfh represents the leak rate of a reciprocating compressor cylinder at the end of this 3 to 5 year lifecycle.[246] We further assume, for purposes of this comment, that rod packing emissions increase linearly across their lifespan, absent specific information about the trajectory of emissions. Based on these figures and assumptions, we estimate that a reciprocating compressor cylinder emits an average of 456 scfh across its lifespan when rod packing is replaced after three years of operating time.[247] Each compressor has an average of 2.5 – 4.5 cylinders,[248] so a conservative estimate is that an average compressor emits about 1,500 scfh.

This estimate suggests that centrifugal compressors equipped with dry seals (even a single dry seal) have fewer emissions than even well maintained reciprocating compressors.[249] As explained in Dr. Sahu's report, dry seal centrifugal compressors are observed to emit the equivalent of 30 to 180 scfh, while reciprocating compressors, again, may be emitting 1,500 scfh or more. *Id.* Furthermore, data from the US Greenhouse Inventory shows that the average centrifugal compressor is many times larger (higher horsepower) than the average reciprocal compressor.[250] As a result the comparison above underestimates the lower emissions of centrifugal compressors. Accordingly, BTSER-level emissions are set by the centrifugal compressors. Therefore, as EPA sets equipment standards for this industry, it must require the use of centrifugal compressors instead of reciprocating compressors wherever such use will not impose unbearable costs on industry.[251]

If EPA does not take this course, it must strengthen the rod packing standard for reciprocating compressors. As noted, wear and tear on rod packing assemblages can increase emissions from 12 scfh to 900 scfh. EPA proposes to require replacement before 26,000 hours of use, the equivalent of three years of continuous usage. EPA should have evaluated a more aggressive rod packing replacement schedule. A more aggressive schedule might result in further cost *savings* to operators by avoiding methane losses. For example a "120 scfh leak reduction rate would require roughly 2 years payback assuming a gas cost of $7/Mcf, a 10% interest rate and 8,000 hours of operation."[252] Of course, the BTSER standard must go beyond only requiring those emission reductions that are actually profitable to the operator. The above merely

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[245] 76 Fed. Reg. at 52,762.
[246] Sahu Report at 26.
[247] *Id.*
[248] TSD at table 6-2, page 6-4.
[249] Sahu Report at 20.
[250] Comparison based on emissions factors and activity data in tables A-121 and A-122, pp. A-153 – A-154, *US Greenhouse Gas Inventory*.
[251] As we later discuss, a rod-repacking standard should, however, be retained for existing reciprocating compressors if and when EPA regulates those facilities.
[252] Copeland and Williams Report at 30 n.125, *see also* Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", p. 8 (October 2006) http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

demonstrates that EPA must investigate whether to shorten the 26,000-hour replacement schedule.

We also ask that EPA consider whether a leak-detection based emissions regime, requiring replacement when emissions cross a certain threshold, constitutes BSER. Because rod packing replacement quickly pays for itself in many scenarios, such a threshold could be low. Some compressors may begin to leak significantly long before the 26,000 hour operation time, but EPA's time-based replacement standard will not address these leaks. If such early failures are at all common, EPA's proposal will unnecessarily allow excess emissions, and so will not constitute BSER. EPA must evaluate this possibility, and, if it declines to adopt a leak-based threshold, must explain why it does not do so.

Beyond rod packing replacement, EPA must evaluate requiring installation of advanced rod packing materials.[253,254]

c. Scope of the Standard

EPA must revisit its decision to exclude wellhead compressors from the NSPS. Wellhead compressors represent a significant fraction of the number of compressors; for example, EPA's figures indicate that 13% of all emissions from new reciprocating compressors are predicted to come from reciprocating compressors at wellheads.[255] With the rapid growth in gas production in recent years, this fraction will grow.

EPA excluded reciprocating wellhead compressors from the standard on the basis of the low VOC emissions from these compressors.[256] EPA has not explained how it determined the level of these emissions. It must do so. EPA appears to have relied, in part, on the conclusion that wellhead compressors are typically "small."[257] A compressor engine survey conducted in Texas states the following: "Some of the findings of this . . . study include: 1. Generally, less than 1% of the well-head engine capacity is comprised by engines smaller that 50 hp; and 2. Generally, 50 to 73% of the well-head engine capacity is comprised by engines greater than 500 hp, depending on

[253] Copeland and Williams, 30.
[254] Rod repacking materials are readily available. *See, e.g.*, EPA, *Methane Savings from Compressors and VRUs* (July 27, 2006) at 5-6 (quantifying emissions reductions and cost savings from rod repacking); EPA, *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems* at 3 (concluding that "[m]onitoring and replacing compressor rod packing systems on a regular basis can greatly reduce methane emissions to the atmosphere and save money"); CECO, *Reduce Gas Emissions: Install CECO Low Emission Packing* (vendor offering rod repacking); CECO, *Low Emission Packing* (2010) (same), attached hereto as Exhibit 94.
[255] Copeland and Williams at 26-39.
[256] 76 Fed. Reg. at 52,762.
[257] *Id.*

the region."[258] We do not consider engines greater than 500 hp as "small." Thus, EPA's assertion regarding the size of the typical wellhead compressor appears unwarranted. We are similarly unable to verify EPA's calculations of the emission rate for wellhead reciprocating compressors (estimated by EPA as 0.044 tpy VOC) or the cost per ton of reducing these emissions (estimated at $84,000).[259] Thus, although EPA purports to distinguish wellhead reciprocating compressors from other reciprocating compressors, this distinction is unsupported, and unreasonable. If EPA wishes to retain the exemption, it must justify it on the record.

EPA has provided no explanation whatsoever regarding its decision to exclude wellhead *centrifugal* compressors from the standard.[260] It must do so. In the absence of a compelling rationale to the contrary, wellhead compressors (of both varieties) must be subject to the same standards as other compressors in the production sector. While EPA does not report methane emissions from wellhead centrifugal compressors in its Greenhouse Gas inventories, implying that there were few or zero centrifugal compressors at wellheads when the basic research behind the inventory was carried out some time ago, this may no longer be true. In any case centrifugal compressors may be installed at wellheads in the future.

d. Compressor Exhaust

EPA has also failed to set a standard for emissions from compressor exhaust. Exhaust from reciprocating internal combustion engines (RICE) and turbines which drive natural gas compressors is a very significant source of methane emissions. In 2009, compressor exhaust accounted for 552,000 metric tons of methane emissions, or 4.6% of the total methane emissions from the oil and gas sector.[261]

While exhaust from some new compressor engines and turbines is addressed under existing standards such as 40 CFR Part 60 Subparts JJJJ and KKKK, according to EPA, these standards do not address methane. EPA offered no evidence that the emissions controls that those standards do require effectively reduce methane. Methane is less reactive than many hydrocarbons[262] and may escape destruction via catalytic oxidation, demonstrating that these other existing standards may be inadequate. Below, we discuss, at length, EPA's obligation to control methane as a pollutant from this sector.

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[258] Houston Advanced Research Center, *Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities, H68 Final Report* (October 2006) pp. 3, attached hereto as Exhibit 95.
[259] 76 Fed. Reg. at 52,762, Sahu at 20-24.
[260] *See* 76 Fed. Reg. at 52,761.
[261] US EPA (2011), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, tables A-120 – A-123 (pp. A-149 – A-155). Figures include scaling for emissions reductions reported to Natural Gas STAR.
[262] Sander, S. P., J. Abbatt, J. R. Barker, J. B. Burkholder, R. R. Friedl, D. M. Golden, R. E. Huie, C. E. Kolb, M. J. Kurylo, G. K. Moortgat, V. L. Orkin and P. H. Wine (2011), "Chemical Kinetics and Photochemical Data for Use in Atmospheric Studies, Evaluation No. 17," JPL Publication 10-6, Jet Propulsion Laboratory, Pasadena. http://jpldataeval.jpl.nasa.gov, attached hereto as Exhibit 96.

Compressor exhaust provides a clear instance where such controls are necessary, and EPA must, therefore, regulate methane from compressor exhaust.

According to emissions factors in the US Greenhouse Gas Inventory, turbines produce less methane (per horsepower-hour) than RICE engines by about a factor of 25.[263] Above, we demonstrate that because centrifugal compressors leak less than reciprocating compressors, centrifugal compressors are the BTSER for VOC emissions from certain compressors. Centrifugal compressors are powered by turbines, unlike reciprocating compressors that are driven by RICE (either can alternatively be powered by electric motors, with zero emissions). Therefore, requiring centrifugal compressors as BTSER will have a substantial co-benefit for methane reductions in the engine/turbine exhaust. A requirement for compressors to be driven by turbines (or electric motors where electricity is available) would therefore be a logical compliment to the centrifugal compressor requirement.

EPA has previously recognized that this is a cost-effective methane abatement option.[264] It must impose standards to control compressor exhaust here.

D. Storage Vessels

1. EPA's Proposal

Because EPA has also proposed (substantively identical) storage vessel standards for new and existing vessels under its proposed NESHAP, the proposed NSPS covers only new and modified vessels not addressed by the NESHAP.[265]

The NSPS standard applies to storage vessels, defined as:

> a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 [tons per year].[266]

Under that standard, storage vessels would essentially have to comply with the NESHAP standard (which is incorporated into the NSPS). That standard requires vessels to be equipped with a cover and closed-vent system, or control device, that channels all

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[263] See emissions factors list in US EPA (2011), Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, tables A-120 – A-122 (pp. A-149 – A-154).

[264] US EPA (2003), *International Analysis of Methane and Nitrous Oxide Abatement Opportunities: Report to Energy Modeling Forum, Working Group 21*, Appendix B, available at http://www.epa.gov/methane/appendices.html, attached hereto as Exhibit 97.

[265] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5395(b)). *See also id.* at 52,769 (proposing to expand the existing NESHAP to cover all storage vessels, not just those with the potential for flash emissions).

[266] *Id.* at 52,810 (Proposed 40 C.F.R. § 60.5430).

emissions to either a combustion device (or flare) or vapor recovery unit ("VRU") with at least 95% control efficiency by weight.[267]

2. BSER Determination

EPA estimates that uncontrolled VOC emissions from storage vessels, in the absence of the NSPS, would be 21,373 tons per year for condensate storage and 23,421 tons per year for crude oil storage.[268] Vapor recovery units, or combustion devices with 95% control efficiency, can reduce VOC emissions by 29,654 tons per year (in 2015).[269]

Assuming, as EPA does, that half of facilities use combustion devices and half use VRUs, EPA's proposed rule would achieve significant VOC reductions at just $143/ton (accounting for additional revenues from recovered condensate).[270]

This is an eminently reasonable control cost, and is reflected in the wide use of vessel emissions control measures throughout the industry. As the Copeland and Williams Report discusses, similar (and more rigorous) control technologies are already in wide use, including in Wyoming, where a 98% control efficiency is required.[271]

EPA Natural Gas STAR documents also support these emissions controls. EPA partners report significant emissions reductions and financial gains. Chevron USA Production Company, for instance, installed VRUs on eight crude oil storage tanks and recovered over $1.2 million in savings, while reducing methane emissions by 21,900 Mcf per year from each unit. The project paid for itself in three months.[272]

We therefore agree with EPA that some combination of combustion devices and VRU on storage tanks, at am minimum, constitutes BSER for this class of facilities. As we discuss below, however, the statute requires EPA to look further, toward emerging control options and improperly excluded sources, in order to set legal emissions standards for this part of the industry..

3. Critiques

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[267] *Id.* at 52,815-16 (Proposed 40 C.F.R. §§ 63.766, 63.771).
[268] TSD at 7-12.
[269] RIA at 3-17.
[270] As we discuss below, it seems likely that combustion devices will be used more frequently than VRUs. This will somewhat raise control costs (though they will remain eminently reasonable). Below, we urge EPA to work to reduce the use of flares, as they produce additional air pollution, while VRUs do not.
[271] Copeland and Williams Report at 54. *See also* Wy. Guidance at 5, 11, 18 (requiring such controls).
[272] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks* (2006) at 10, available at: http://www.epa.gov/gasstar/documents/ll_final_vap.pdf, attached hereto as Exhibit 98.

Field data and state regulations demonstrate that EPA must raise control efficiency requirements, and minimize flaring, in order to ensure that the proposed standards reflect BSER. In addition, EPA must limit exemptions to these standards and cover all storage vessels and similar impoundments, pits, sumps, and well cellars, including those that contain produced water. EPA must also revise the regulatory text to eliminate confusing cross references which may impede compliance and enforcement efforts.

a. Tighten Emission Control Requirements

EPA must raise its control efficiency requirements and limit, or eliminate, the use of combustion devices.

Initially, EPA provides only limited support for the proposition that a 95% control efficiency constitutes what may be "fairly projected for the regulated future."[273] On the contrary, EPA's own Natural Gas STAR documents report that VRUs can "recover *over* 95 percent of the hydrocarbon emissions that accumulate in storage tanks."[274] A 98% control efficiency is, again, achievable, and is required in Wyoming.[275] Because these controls are widely-used, their level of control is plainly "[a]n achievable standard."[276] EPA's proposal thus falls below BSER, and must be strengthened.[277]

We are also unpersuaded that EPA has achieved the right balance between VRUs and flares, in light of the serious adverse environmental impacts of flaring. As EPA explains:

> A VRU has a potential advantage over flaring, in that it recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold, as well . . . . A VRU also does not have secondary air impacts that flaring does . . . .[278]

These flaring impacts include NO_x, SO_2, and PM emissions, as well as emissions of other pollutants.[279] EPA must avoid these impacts wherever feasible.

We recognize that EPA determined it could not simply select VRUs as reflecting BSER for storage vessels because "a VRU cannot be used in all instances."[280] But that is not the statutory standard for new source emissions under 111(b). EPA must ensure that VRU-

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[273] *Lignite Energy Council*, 198 F.3d at 934.
[274] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks* (2006) at 1.
[275] *See* Wy Guidance at 5, 11, 18 (requiring such controls).
[276] *See Essex Chem. Corp.*, 486 F.2d at 433.
[277] *See also* Copeland and Williams Report at 50 (describing these higher control efficiencies).
[278] 76 Fed. Reg. at 52,763.
[279] *See id.*; *see also* TSD at 7-17 (listing flaring emissions, including THC, CO, CO_2, NOx, SO_2, and PM).
[280] 76 Fed. Reg. at 52,763.

level control efficiencies are achieved in all applications so long as that does not impose exorbitant costs on industry (EPA now predicts that only 50% of new sources will use VRUs, while the remainder will flare.)[281] It must do so by requiring all affected sources to achieve control efficiencies of 98%, with no secondary emissions of NO_x, except where the operator can demonstrate to EPA that it cannot install a VRU. In that case (and only that case) EPA could allow a 95% control efficiency (which can be met either by VRU or flare), with that exemption subject to review or challenge. Such an approach is structurally similar to EPA's efforts to construct an exemption from its "low-bleed" standard for controllers,[282] and would similarly hold operators to a higher standard, with limited exemptions. EPA must adopt it.

b. Limit Exemptions

EPA proposes to exempt "small throughput" storage vessels – that is, vessels with either an average condensate throughput of less than 1 barrel per day per vessel or average oil throughput of less than 20 barrels per day per vessel.[283] These throughput rates translate into a 6.1 ton per year per tank VOC emission rate for condensate tanks and a 5.8 ton per year per tank VOC emission rate for crude oil tanks.[284] This exemption is not lawful.

Initially, EPA's own calculations show that the annualized cost of installing a VRU is $18,983 and $8,909 for a flare – translating into control efficiencies of about $3,000 per ton of VOC emissions reduced for a VRU (depending on the tonnage of emissions captured).[285] These are not exorbitant costs – certainly far less than the greatest that "the industry could bear and survive."[286] In exchange for these costs, EPA would significantly reduce VOCs at these facilities – by 5.77 tons per year per tank for condensate tanks and 1.4 tons per year per tank for crude oil tanks.[287] These are substantial emissions reductions at fairly low costs. EPA must, therefore, either abandon or strictly limit the exemption.

If the exemption is limited, however, rather than abandoned, it must be revised in several respects:

First, in order to avoid exempting substantial cumulative emissions from tank farms that contain numerous tanks which may fall below EPA's applicability threshold, EPA must structure its exemption (whatever the thresholds) to apply to tank batteries, rather than

[281] TSD at 7-24
[282] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(a))
[283] *Id.* at 52,800 (Proposed 40 C.F.R. § 60.5395(a)(1)-(2)).
[284] TSD at 7-19, 7-21.
[285] These projected costs are likely too high. *See infra* Section VII(B)(2)(f).
[286] *See Portland Cement II*, 513 F.2d at 508.
[287] *See* TSD at 7-19, 7-21.

to individual tanks.[288] This may be what EPA intended the current proposal to accomplish, because its proposed storage vessel definition includes a "series of stationary vessels that are either manifolded together or are located at a single well site."[289] This intent is not clear from the preamble, however. EPA must therefore either confirm that its standards (and exemptions) are intended to apply to vessels both individually and cumulatively, or must revise them accordingly.

Second, EPA must, at a minimum, limit the exemption to truly small tanks with truly small emissions. Because the public experiences adverse impacts from *emissions*, rather than throughput, EPA must base its exemption on emissions thresholds. These thresholds must be set at the lowest reasonable point, which is below the current thresholds.

Specifically, for condensate storage vessels, a 3 ton/year emissions rate would reach 1,782 tanks, reducing each tank's emissions by 95%, at a cost of only $6,576 per ton of VOC. For crude oil tanks, a 1.5 ton/year emissions cut-off would trigger 95% emissions reductions at 825 tanks for $13,686/ton. These costs are clearly reasonable, and will produce substantially greater benefits than those flowing from the thresholds that EPA proposes to use. We therefore assert that EPA must limit its exemption to tanks with these lower emissions rates.

We further note in this regard that EPA's cut-off in proposed 40 C.F.R. § 60.5395 appears to be in tension with its underlying storage vessel definition. That definition defines storage vessels as including only those tanks that "have potential for VOC emissions equal to or greater than 10 tpy."[290] But even using EPA's proposed thresholds, the smallest emissions rate tanks covered by the standards would have emissions of 6.1 tons per year (condensate) and 5.8 tons per year (crude oil).[291] EPA presumably does not intend to exempt tanks with these emissions from all control just because their emissions are below 10 tons per year of VOC. EPA must therefore delete the "10 tpy" language from its definition section, as it conflicts with the lower emissions threshold it sets in the substantive storage vessel standard itself.

Third, EPA should further condition its exemption by limiting it to only small throughput tanks with low vapor pressure. Such an exemption would ensure that only tanks which do not contain significantly volatile substances are exempt.

Such vapor pressure limitations are used in certain California air quality districts. The Santa Barbara County Air Pollution Control District, for instance, exempts tanks whose vapor pressure is below 0.5 lb/sq. in,[292] and the Ventura County Air Pollution Control

[288] *See* Sahu Report at 24-25.
[289] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[290] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[291] TSD at 7-19, 7-21.
[292] SBAPCD Rule 325(B)(1)(a), attached hereto as Exhibit 99.

District takes a similar approach (using VOC content rather than vapor pressure), and exempts tanks with a VOC concentration of 5 mg/L of water or below.[293] EPA must follow suit and condition its exemption similarly.

c. Address Additional VOC Sources Arising from Liquid Storage

Storage vessels are not the only liquid storage systems that emit VOCs. Well cellars, sumps, and even pools of oil can and do emit substantial VOCs, which are controlled by several different state regulators. EPA must include standards for such sources based upon these available controls.

Examples of such controls are plentiful, especially among the California air districts. In particular:

- The South Coast Air Quality Management District prohibits well cellars with a total organic compound concentration of greater than 500 ppm,[294] bars organic liquid storage in well cellars, and requires regular monitoring,[295] Since 2006, no well cellar may vent any natural gas to the atmosphere.[296]

- The Santa Barbara County Air Pollution Control District requires regular pumping of well cellars.[297] It also bars all "primary sumps" – that is, any sump that receives oil and produced water directly from field gathering or production systems – and requires that all pits and post-primary sumps (which receive their liquids after separation processes) be replaced with tanks or covered, with a vapor recovery unit.[298]

- The Ventura County Air Pollution Control District likewise bars "first stage production sumps" and requires all other sumps, pits, and pounds to be covered.[299]

- The San Joaquin Valley Air Pollution Control District requires all sumps to be covered with a material impervious to VOCs.[300]

- The Bay Area Air Quality Management District bars all "open liquid pools of crude oil or condensate" and all uncovered vessels larger than 250 ml; it also requires that all well cellars be covered.[301]

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[293] VCAPCD Rule 71.4(C)(1)(c), attached hereto as Exhibit 100.
[294] SCAMD Rule 1148.1(d)(1), attached hereto as Exhibit 112
[295] Rule 1148.1(d)(2)-(3).
[296] Rule 1148.1(d)(6).
[297] SBCAPCD Rule 344(D)(3), attached hereto as Exhibit 113
[298] Rule 344(D)(1)-(2).
[299] VCAPCD Rule 71.4(B)
[300] SJVAPCD Rule 4402(5), attached hereto as Exhibit 114

EPA neither discusses these precedents, nor acknowledges the existence of VOCs from sumps, pools, and well cellars. As a result, it has unreasonably left these sources unregulated.

In the final rule, EPA must include standards for each liquid storage source, including, but not limited to, sumps, pools, pits, pounds, and well cellars, or provide a legally-supportable rationale as to why it will not follow the (decades-old) control precedent set by the California air quality control districts.

d. Address Produced Water

Produced water storage (including ponds and tanks) constitutes an important subset of the liquid storage systems we discuss above. Produced water is a significant VOC source, and EPA must control it properly.

First, at an absolute minimum, EPA must make clear that its proposed standards apply to produced water tanks. Wyoming already requires new produced water *tanks* to achieve the same 98% emissions control that it requires of crude oil and condensate tanks.[302] The Santa Barbara County Air Pollution Control District likewise requires produced water tanks to be controlled to a 90% efficiency.[303] These examples demonstrate that controls are plainly available and effective, but EPA has not included produced water tanks in its storage vessel definition. It must do so.

Second, EPA needs to develop controls for produced water ponds and sumps, holding these sources to a similarly rigorous control efficiency standard.

EPA "believes that produced water ponds are . . . a potentially significant source of emissions," and is seeking comment on control options for these ponds.[304] We agree that produced water can produce significant VOC emissions. Some reports do establish that these ponds emit harmful pollution. EPA research has shown that produced water ponds used by the oil and gas industries can emit VOCs including the hazardous pollutants benzene, toluene, xylenes, and methanol.[305] New York State has also gathered data on emissions from impoundments, and concluded that these impoundments could be significant sources of the hazardous air pollutant methanol:

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[301] BAAQMD Rules 8-37-302 & 8-37-303, attached hereto as Exhibit 115
[302] Wy Guidance at 16, 20.
[303] *See* SBCAPCD Rules 344(D)(2)(a); 325(D).
[304] 76 Fed. Reg. at 52,756.
[305] Thoma, E. (2009) *Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1. Final Report.* EPA Report EPA/600/R-09/132. Available at http://www.epa.gov/nrmrl/pubs/600r09132/600r09132.pdf, attached hereto as Exhibit 101.

> Analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals potential for emissions of hazardous air pollutants (HAPs), in particular methanol, from the recovered (flowback) water stored in central impoundments. This methanol is present as a major component of the surfactants, cross-linker solutions, scale inhibitors and iron control solutions used as additives in the frac water. Current field experience indicates that an approximately 25% recovery of fracturing water from Marcellus shale wells may be expected. Thus, using a 25% recovery factor of a nominal 5,000,000 gallons of frac water used for each well, an estimated 6,500 pounds (3.25 tons) of methanol will be contained in the flow- back water. Since methanol has a relatively high vapor pressure, its release to the atmosphere could possibly occur within only about two days after the recovered water is transferred to the impoundment. Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission of 32.5 tons (i.e., "major" quantity of HAP) is theoretically possible at a central impoundment.[306]

Because VOCs and hazardous air pollutants are likely co-emitted from these sources, they appear to be potentially significant emissions sources, warranting coverage by these standards.

Pit emissions can be estimated using EPA's own test methods. The Ventura County Air Pollution Control District uses EPA Method 8015, which requires sampling of only a small portion of the pit surface.[307]

As we discuss above, California air districts in areas with oil and gas production have long controlled emissions from produced water ponds, by, for instance, requiring such ponds to be covered, or that their emissions be captured or flared, or simply by requiring ponds to be replaced by tanks.[308] These standards are described in the section above, on liquid storage.

The Santa Barbara County Air Pollution Control District, the Ventura County Air Pollution Control District, and the Bay Area Air Quality Management District, in particular, have all banned at least certain forms of open liquid storage (such as "primary sumps"), ordering that they be replaced with well-controlled tanks (equipped with appropriate

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[306] *Draft New York Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program* (Sept. 30, 2009) at section 6.5.1.8, attached hereto as Exhibit 102. New York's recent revised impact statement (Sept. 2011) does not contain this statement, but only because "[t]he Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments" and therefore did not address "these practices" in the revised document. *See* Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program (September 2011) at section 1.1.1.1, attached hereto as Exhibit 103.
[307] VCAPCD Rule 71.4(F).
[308] See VCAPCD Rule 71.4 & SBCAPCD Rule 325.

flares or VRUs). Tanks are inherently more readily managed then pits, so the lowest-possible emissions rate from a tank constitutes BSER.

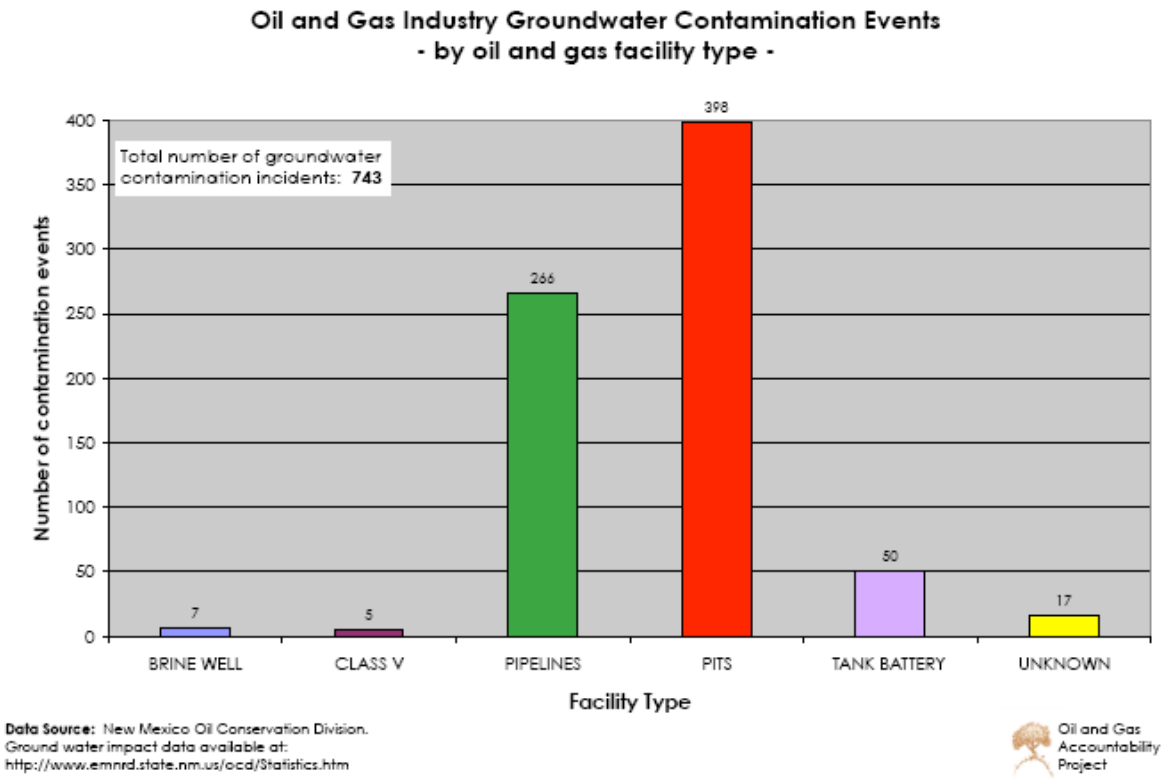
Because this technology is available, and in use, it plainly constitutes BSER for liquids storage. EPA must therefore set emissions standards for produced water based upon the emissions rate from well-controlled tanks. (And, to the extent it determines that some classes of produced water storage cannot be managed in tanks, EPA must continue to follow the path blazed by the California air districts, and set BSER standards based, at a minimum, upon *covered* and well-controlled impoundments).

Such a standard also would produce significant "non-air quality health and environmental" benefits, especially to the extent that operators opted to avoid using pits, in lieu of tanks, and because covers help prevent spills and falls into pits. Surface spills and leaks from waste pits pollute water across the country, so eliminating these pits would greatly reduce water pollution issues associated with oil and gas extraction. The open pits and ponds also pose a significant risk to livestock and to wildlife, such as birds that alight on them and small animals that use them for drinking water.

For instance, New Mexico data, summarized by the Oil and Gas Accountability Project, show 743 instances of ground water contamination, almost all of it occurring over the last three decades. 398 of those incidents – over half – are linked to faulty pits.[309]

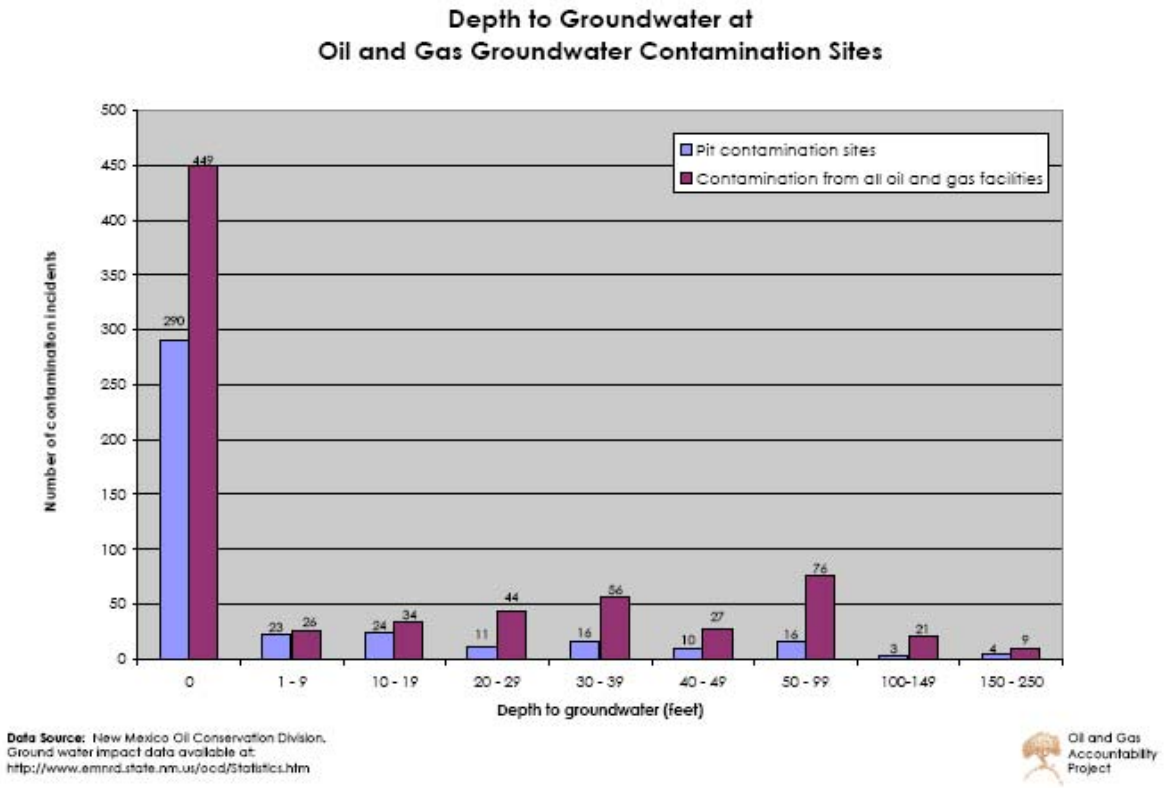
Figure 3

[309] OGAP Analysis of data provided in New Mexico Energy, Minerals and Natural Resources Dep't, Oil and Conservation Div., *Cases Where Pit Substances Contaminated New Mexico's Ground Water* (2008). OGAP Analysis and raw data available at http://www.earthworksaction.org/NM_GW_Contamination.cfm, attached hereto as Exhibit 104.



The bulk of pit contamination is associated with shallow groundwater, of the sort which can readily flow into drinking water wells, as the New Mexico data demonstrate:

Figure 4



Similar incidents are occurring across the country. [310] In Pennsylvania, for instance, state authorities were forced to quarantine cattle after a pit leaked into their field, collecting in a smelly pool that killed the grass.[311] In Colorado, leaky pits with torn liners spilled more than 6,000 barrels of waste,[312] and one leaking pit contaminated drinking water with benzene. In state after state, poorly-regulated and inspected pits are imperiling the public.

Thus, EPA rules requiring produced water to be sequestered in tanks, or, at a minimum, discouraging the use of uncovered pits by setting rigorous emission control standards, would not only control VOCs, but also make important progress on controlling water pollution from these sources.

To the extent that EPA needs additional data to support such a requirement, e.g., data on emissions from pits, available controls for achieving substantial emission control

[310] *See generally*, Natural Resources Defense Council, Petition for Rulemaking to Regulate Oil and Gas Waste (Sept. 8, 2010) (collecting these incidents), attached hereto as Exhibit 105.

[311] Pro Publica, Nicolas Kusnetz, *A Fracking First in Pennsylvania: Cattle Quarantine* (July 2, 2010), available at http://www.propublica.org/article/a-fracking-first-in-pennsylvania-cattle-quarantine, attached hereto as Exhibit 106.

[312] *See* Colorado Oil and Gas Conservation Commission, Inspection/Incident Inquiry, Spill Reports Doc. Nos. 1630424, 1630436, 1630427, 1630428, 1630429, 1630430, all attached hereto as Exhibit 107.

from pits, and/or costs of converting from pits to tanks, it must specifically request such information from companies under section 114.

e. Textual Issues

Finally, EPA must revise the rule text to avoid cross-references to its NESHAP standard. At present, the proposed rule simply cites to the NESHAP for its emission standards,[313] but this cross-citation is confusing, as the cited sections – and the sections that they, in turn, cite – are rooted in section 112 concepts, and include references to hazardous air pollutant control requirements. EPA must, therefore, place its NSPS emission control standards directly in the text of the NSPS rule.

E. Leak Detection

1. EPA's Proposal

In proposing the revised NSPS, EPA evaluated potential leak detection and repair ("LDAR") requirements for all facilities in the oil and gas production sector. EPA considered four potential LDAR programs: (1) monthly monitoring in accordance with 40 C.F.R. subpart VVa; (2) annual monitoring to the standard imposed by subpart VVa plus monthly optical monitoring; (3) monthly optical monitoring alone; and (4) annual optical monitoring alone.[314] Based on this evaluation, EPA proposes to adopt subpart VVa for processing plants but not to adopt any LDAR requirement for other oil and gas production facilities.

Specifically, under the existing regulation, 40 C.F.R. subpart KKK, § 60.632(a), onshore natural gas processing facilities must comply with subpart VV, but EPA proposes to update the standard to require compliance with subpart VVa.[315] All other facilities are currently unregulated, and EPA concluded that no LDAR program was "cost effective" for these facilities, accordingly declining to adopt a standard.[316]

2. Critique

We agree that subpart VV no longer reflects BSER for onshore natural gas processing plants, and that subpart VVa presents a feasible and cost-effective improvement. Nonetheless, EPA must go further before it is compliant with the statute. It must consider various combinations of subpart VVa and optical monitoring. State programs and consent decrees EPA has entered both demonstrate the efficacy and feasibility of stricter programs with fewer exemptions, and EPA must adopt a stronger standard here.

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[313] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5395(a))
[314] 76 Fed. Reg. at 52,754-55 (discussing processing plants), 52,764-66 (discussing other facilities).
[315] 76 Fed. Reg. at 52,800, (Proposed 40 C.F.R. § 60.5400). Both VV and VVa were developed for the Synthetic Organic Chemicals Manufacturing Industry.
[316] 76 Fed. Reg. at 52,766.

As to other facilities, although EPA determined that an overall LDAR program was unwarranted, EPA must have examined whether LDAR was warranted for particular device types.

a. Processing Plants

The existing VOC regulations for natural gas processing facilities, 40 C.F.R. subpart KKK, incorporate the LDAR provisions of 40 C.F.R. subpart VV. The subpart VV standards were developed in 1981, and subpart KKK was adopted in 1985.[317] Since that time, much has been learned about what it takes to have an effective leak detection program. Notably, investigations by EPA Regional and National Enforcement Investigations Center personnel detected massive fraud in the conduct of LDAR inspections and in the reporting of results.[318] Enforcement action induced negotiations with operators of most of the nation's refineries led to consent decrees that substantially improved the real-world effectiveness of those programs and the development of Best Practice Guidelines.[319] Similarly, various states and regional entities have adopted LDAR programs.[320,] Many of these consent decrees and state regulations are more stringent than the subpart VVa regulation EPA proposes to adopt for processing plants. Yet EPA's BSER review did not examine these activities and practices. EPA must either adopt elements of these more stringent programs as BSER or explain why these elements are infeasible.

The most basic elements of an LDAR program are the definition of a leak (expressed as parts per million of the leaked substance), the frequency of monitoring, and the timeline in which leaks are repaired once discovered. Subpart VVa improves upon subpart VV by reducing the leak detection threshold: for pumps in light liquid service, the leak threshold is lowered from 10,000 ppm to 2,000 ppm, and for valves in gas/vapor and

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[317] 50 Fed. Reg. 26122 (June 14, 1985) (Exhibit 1); *see also* 50 Fed. Reg. 40158 (Oct. 1, 1985) (Exhibit 2).

[318] In the late 1990's EPA discovered flagrant, industry-wide violations of several CAA requirements at the nation's refineries. Among the most significant violations were LDAR rules violations where refiners, and independent contractors hired by refiners, routinely underreported by up to a factor of 10 the number of leaking valves, leading to significant excess emissions. The ensuing enforcement actions led to 29 settlements with operators over 90 percent of the refining capacity in the country. These settlements required improved LDAR practices, $82 million in fines and $75 million in Supplemental Environmental Projects. This experience demonstrates a need for detailed independent oversight of LDAR activities, as does the recent Pelican refinery criminal prosecution. In the absence of a sustained Federal focus on this issue and recognizing the likely lack of state resources in the near future, it would seem that MACT should include some form of independent auditing of LDAR programs. EPA could require an independent audit of sources with large number of components, perhaps once every five years.

[319] See, e.g., Leak Detection and Repair, A Best Practices Guide, p. 22-23, http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf (discussing these consent decrees), attached hereto as Exhibit 108

[320] *See, e.g.*, Bay Area Air Quality Management District regulation 8-18 (adopted Sept. 15, 2004), attached hereto as Exhibit 109

light liquid service, where the leak threshold is lowered from 10,000 ppm to 500 ppm.[321] EPA does not propose to strengthen the monitoring frequency and repair times. The Bay Area Air Quality Management District ("BAAQMD") has demonstrated that stricter regulation is feasible. The BAAQMD supervises LDAR programs at 5 refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under Regulation 8, Rule 18 (Reg 8-18). This regulation, first adopted in 1998, sets lower leak limits, more frequent inspections, and shorter repair schedules than the proposed rule, as summarized in Table 1, below.

Table 1

	Current Rule	Proposed Rule	BAAQMD Rule 8-18
Leak definition – valves in gas/vapor/light liquid services	10,000 ppm	500 ppm	100 ppm
Leak definition – pumps in light liquid service	10,000 ppm	2,000 ppm	500 ppm
Inspection frequency	Monthly/quarterly[322]	Monthly/quarterly	Quarterly/annual[323]
Repair schedule	15 days[324]	15 days	7 days[325]

In addition to having a lower leak threshold, the BAAQMD rule is stricter than the VV and VVa rules because it requires monitoring for methane leaks. Subparts VV and VVa (with incorporation of EPA Method 21) do not specifically require the use of leak detection equipment which is sensitive to methane. Since methane is the main component of natural gas, this oversight can potentially significantly diminish the effectiveness of leak detection at a specified threshold. EPA should therefore either specify that leak-detection equipment be sensitive to methane and adopt BAAQMD's lower threshold or explain why these steps are infeasible for natural gas processing plants.[326]

[321] It should be noted that the 10,000 ppm limit is an absolute limit; while the limit of 500 ppm is "500 ppm above background." Reportedly, background concentrations can be expected to be approximately 100 ppm.

[322] If a component is not found to be leaking in two consecutive months; the inspection frequency is reduced to once per quarter. Thus, the majority of components are inspected quarterly

[323] Pumps are subject to daily visual inspection. If a valve has not been found to be leaking during five quarterly inspections, the inspection frequency is reduced to once per year.

[324] An initial attempt to repair must be made within 5 days.

[325] If the leak is detected by BAAQMD personnel during an inspection it must be repaired within 24 hours. The BAAQMD rules also require that leaks detected by the source be minimized within 24 hours.

[326] As noted, BAAQMD has applied these rules to refineries, chemical plants, and terminals. Although BAAQMD does not appear to regulate any natural gas processing plants, EPA has historically subjected natural gas processing plants to the same regulations as these other facility types.

Another key aspect of an LDAR program is the scope of any exemptions recognized by the program. Subpart VV exempts devices from monitoring if it is "unsafe" or "difficult" to monitor them.[327] Subpart VV further allows operators to delay repair of leaking devices: an operator may delay repair of devices where repair would require a shutdown of the process, and an operator may forgo repairs of 2% of the total number of devices provided the operator conducts weekly rather than monthly monitoring.[328] These exemptions were carried over into Subpart VVa.[329] EPA must review these exemptions in light of the experience in California and elsewhere and determine whether exemptions at these levels continue to be consistent with the notion of "best system of emission reductions." For example, BAAQMD does not recognize an exemption for devices that are unsafe to monitor. Similarly, whereas the proposal would allow 2% of devices to be designated as nonrepairable, BAAQMD limits the number of nonrepairable devices to 0.025% to 1%, depending on the device category.[330]

A particularly troubling exemption in EPA's proposed standard is that EPA proposes to waive LDAR requirements where the gas stream is less than 10% VOC by weight. Proposed subsection 60.5400(f) states that:

> [e]ach piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process.

EPA's preamble provides no discussion of this exemption, and we are aware of no basis for it. This LDAR exemption will likely apply to many, if not all, compressors, valves, pressure relief devices and connectors downstream of processing unit dehydrators; indeed, EPA reports that processed gas is only 2.8% VOC by weight.[331] Although devices used with low-VOC gas streams will by definition have lower VOC emissions, VOC leaks from these devices may still be significant. Addressing these leaks will certainly have important methane benefits. Accordingly, EPA must either remove the exemption or provide a justification for continuing to provide it.

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[327] 40 C.F.R. §§ 60.486(f), 60.482-2(g), 60.482-7(g)-(h), 60.482-10(j)-(k).
[328] 40 C.F.R. §§ 60.483-1, 60.482-7(a)(2)(ii).
[329] 40 C.F.R. §§ 60.486a(f), 60.482-2a(g), 60.482-7a(a)(2)(ii), (g), (h), 60.482-10a(j)-(k), 60.482-11a(e), 60.483-1a, 60.483-2a(b).
[330] The BAAQMD limit on the number of non-repairable components it 0.3 percent for valves, 0.025 percent for valves with major leaks (leaks greater than 10,000 ppm, including methane) and 1.0 percent for pumps and compressors. It also requires mass emission testing for non-repairable components with high leak rates and places an emission limit of 15 pounds per day on non-repairable components. The SCAQMD limit is 0.5 percent for valves and 1.0 percent for pumps.
[331] *See* TSD at 6-2.

The LDAR program furthermore must incorporate elements beyond thresholds and schedules. The alternate compliance option and allowable level of designated "difficult to monitor" valves must be reviewed in light of the performance of best performing LDAR programs. For example, EPA must limit the exemptions for devices that are difficult or unsafe to monitor or repair by providing that when such devices are replaced, they must be replaced with hermetically sealed (leakless) designs. Use of advanced "leakless" components in these locations should be cost-effective since (1) the cost of monitoring, repairing and re-monitoring devices that are difficult to monitor is substantially higher than components in more convenient locations; (2) the conversion to leakless technology would only occur when a new valve is being installed; and (3) the potential emissions from leaking "inaccessible" components is greater since a leak is less likely to be observed visually or by sense of smell and instrumented monitoring only occurs annually. Since the NSPS only applies to newly installed components, advanced technology components must be required at the time of initial installation for those components that, if they leaked, would require a plant shutdown to repair. EPA must also explore whether optical scanning provides a way to monitor devices that would be difficult or unsafe to monitor using traditional monitoring techniques.

Another approach EPA must use is to require "repeat offenders" to be replaced. The South Coast Air Quality Management District and the Ventura County Air Pollution Control District each have rules under which components that have been subject to repair more than, *e.g.*, 5 times within a year be replaced with BACT/BARCT or be vented to an approved air pollution control device.[332]

Finally, EPA must ensure the integrity of the LDAR program. As EPA's history of enforcement actions demonstrates, this integrity cannot be taken for granted.[333] EPA has, as we note above, encountered significant fraud in previous leak detection efforts. To avoid this, it must include safeguards in its rules, including requiring a professional engineer to sign off on all LDAR reports. EPA must also explore requiring periodic independent audits of LDAR programs, at least for larger processing plants.

Optical Scanning

In three of its four options, EPA considered the use of optical scanning devices as a means of reducing LDAR inspection frequencies, and EPA specifically requested comment on the role of optical scanning. Current and even advanced LDAR programs

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[332] See, SCAQMD Rule 1173(g)(3), attached hereto as Exhibit 110 and Ventura County APCD Rule 74.7, attached hereto as Exhibit 111. Under the Ventura County rule, for example, if a valve is found to have suffered 5 major leaks in a year is shall be replaced by a valve with a bellows seal, or with graphite, PTE or PTFE stack chevron seal rings, or with BACT technology level components.

[333] For a more recent example, see EPA's recent refinery settlements. See, e.g. http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html, attached hereto as Exhibit 116.

have been shown to be cost-effective BSER. EPA is correct that optical scanning devices have not been shown to be as effective as LDAR programs, and, as pointed out, cannot quantify emissions. Optical scanning programs can, however, be a part of an overall improved LDAR program. Use of optical cameras involves some modest level of investment; however, once purchased, these devices can provide an extremely low cost means of filling the gaps in the LDAR program. Daily or weekly scans can identify plant areas containing gross emitters (including "unsafe to monitor" or "difficult to monitor" components) for targeted LDAR inspections. Such inspections could replace scheduled inspections and save operators money by detecting leaks early, while improving the environmental performance of the facility. Use of optical scanning devices, pressure relief valves, monitoring devices and other technical advances can complement existing programs. However, the suite of existing options have not demonstrated the ability to provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs. For this reasons these options must be considered in addition to and not *in lieu of* existing programs.

Defining affected facilities

The Clean Air Act provides that NSPS apply to "stationary source[s]," which include individual "facilit[ies]." CAA §§ 111(a)(3), (b)(1). Each individual NSPS defines the "affected facilities" it regulates. *Star Enter. v. EPA*, 235 F.3d 139, 142 (3d Cir. 2000), *Sierra Pac. Power Co. v. EPA*, 647 F.2d 60, 66 (9th Cir. 1981).

The proposed regulation, as it applies to onshore natural gas processing plants, defines "affected facility" to include two things: an individual "compressor in VOC service or wet gas service," or "[t]he group of all equipment, except compressors, within a process unit." Proposed 40 C.F.R. § 60.5365(f)(1)-(2). "Process unit" is defined as "components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products." § 60.6430.

Operators and enforcement staff are likely to disagree over what constitutes a "process unit." The definition must be expanded to include all common gas processing processes, as follows:

> Gas processing plant process unit means equipment assembled for dehydration of natural gas, the sweetening of gas, the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

b. Non-Processing-Plant facilities

EPA does not propose any form of LDAR for non-processing-plant facilities, including the wellheads, compressors, pneumatics, and storage facilities otherwise regulated by the proposal.[334] EPA concluded that the two options involving subpart VVa-type monitoring were not "cost effective." [335] For the two options involving solely optical monitoring, EPA was "unable to estimate their cost effectiveness" because EPA could not estimate the amount of VOC reductions these programs would achieve.[336]

At a minimum, EPA must evaluate whether monitoring is BSER for specific components, and justify its decision not to apply it. For example, EPA concluded that Subpart VVa had a cost of control of $6,079 per ton of VOC as applied specifically to valves at gathering lines and boosting stations, and that modified subpart VVa as applied to these same valves had a cost effectiveness of $5,221 per ton.[337] Although EPA has not articulated a cutoff for reasonable control costs, these numbers resemble other figures that EPA has concluded are cost effective. For example, in discussing LDAR for processing plants, EPA concluded that switching from subpart VV to subpart VVa would have a cost-effectiveness of $3,352 per ton of VOC, including $4,360 for connectors, and that this was cost-effective.

Furthermore, it appears that EPA's cost estimates are unduly conservative, in that two prior studies found LDAR programs to be more cost-effective than does the current proposal. EPA's own 2009 Methane to Markets presentation identified drastically lower LDAR costs per device monitored.. A separate Canadian study determined that, *inter alia*, 75 to 85 percent of leaks are economic to repair. Thus, EPA may be overstating the cost of LDAR programs for non-processing-plant facilities, and EPA must at least reconcile its current cost estimates with those in EPA's 2009 Methane to Markets report.

F. SO_2 Emissions from Gas Processing Plants

1. EPA's Proposal

Gas processing plants are significant SO_2 sources because the removal of H_2S from "sour" gas results in SO_2 emissions.[338] EPA's Subpart LLL control standards, which are calibrated by the sulfur feed rate at a given facility, set a maximum required control efficiency of 99.8% for facilities with sulfur feed rates greater than 5.0 long tons/day

[334] 76 Fed. Reg. at 52,766.
[335] *Id.*
[336] *Id.* at 52,765-66.
[337] 76 Fed. Reg. at 52,765.
[338] *See* 49 Fed. Reg. 2,656, 2,658 (Jan. 20, 1984) (describing these emissions), attached hereto as Exhibit 117.

(LT/D) and a gas stream with greater than 50% H_2S content.[339] These standards were set in 1984, and EPA now proposes to update them. A database search shows two facilities which meet EPA's feed rate and H_2S content standards which can achieve a 99.*9*% control efficiency.[340] EPA therefore proposes to raise its maximum control efficiency to 99.9%, consistent with these achieved emissions reductions.

2. BSER Determination

We agree with EPA that, as facilities with high sulfur feed rates can achieve a 99.9% control efficiency, the existing 99.8% feed rate no longer reflects BSER/BDT. We therefore support EPA's decision to raise the maximum required control efficiency consistent with control rates achieved by the sources in EPA's database.

G. Conclusion

In sum, EPA's proposal is a substantial improvement over the status quo, but must be improved to be fully compliant with section 111's forward-looking technology forcing requirements as we describe above.

III. EPA MUST ADD SEVERAL MISSING SOURCE TYPES TO THE NSPS

Throughout these comments, we have noted opportunities for EPA to control certain source categories which the rules do not now appear to cover, including conventional well liquids unloading and produced water ponds and tanks. Three other omitted source types are also important here, and must be included in the standards because section 111, as we discuss above, requires EPA to comprehensively regulate each listed source category (or justify its failure to do so) upon each eight year review and revision. These source categories are: (a) offshore sources, (b) heater-treaters; and (c) oil and gas field engines, including rig engines.

A. Offshore Sources

EPA has the authority, and the obligation to regulate the emissions of portions of the offshore oil and gas production sector. The Outer Continental Shelf Lands Act ("OCSLA") explicitly *extended* the "laws and civil and political jurisdiction of the United States" to the Outer Continental Shelf, cementing the relevance of domestic environmental law to that region.[341] In doing so, Congress recognized that the shelf is "a vital national resource reserve held by the Federal Government for the public," and which is "subject to environmental safeguards."[342] In fact, Congress even ordered the Secretary of the

[339] *See* 40 C.F.R. § 60.642.
[340] 76 Fed. Reg. at 52,755-56.
[341] *See* 43 U.S.C. § 1333(a)(1).
[342] *See* 43 U.S.C. § 1332(3).

Interior, who oversees leasing programs in the region, to "cooperate with the relevant departments and agencies of the Federal Government" to enforce "environmental laws."[343]

The Clean Air Act provides, in turn, that following the passage of the 1990 Amendments, EPA:

> [s]hall establish requirements to control air pollution from Outer Continental Shelf sources located offshore of the States along the Pacific, Arctic, and Atlantic Coasts, and along the United States Gulf Coast off the State of Florida eastward of longitude 87 degrees and 30 minutes ("OCS sources") to attain and maintain Federal and State ambient air quality standards *and* to comply with the provisions of [the Prevention of Significant Deterioration Program].[344]

Section 111 standards are, of course, designed to "supplement" ambient air quality standards by ensuring that new and modified sources of air pollution in all areas comply with rigorous emissions controls.[345] As such, EPA must extend these regulations to "attain and maintain" air quality to OCS sources.

The Act goes on to specify that, for OCS sources "located within 25 miles of the seaward boundary of such states":

> such requirements shall be the same as would be applicable if the source were located in the corresponding onshore area, and shall include, but not be limited to, State and local requirements for emission controls, emissions limitations, offsets, permitting, monitoring, testing, and reporting.[346]

The NSPS clearly fit within this inclusive collection of requirements, even though they are federal requirements, as they are, again, regulations designed that support attainment and maintenance of air quality standards. And the use of "shall" in the directive from Congress to establish regulations aimed at attaining and maintaining the NAAQS and comply with the PSD program indicates that EPA must extend the NSPS in over Outer Continental Shelf sources.

Significantly, Congress declared that EPA "shall update such requirements as necessary to maintain consistency with onshore regulations."[347] Because EPA is updating the NSPS for onshore sources, it must therefore update and extend the NSPS to corresponding offshore sources within the 25 mile boundary.

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[343] *See* 43 U.S.C. § 1334(a).
[344] 42 U.S.C. § 7627(a)(1).
[345] *See*, *e.g.*, *NRDC v. Train*, 545 F.2d 320 (2nd Cir. 1976), attached hereto as Exhibit 118.
[346] 42 U.S.C. § 7627(a)(1).
[347] *Id.*

It is particularly important that EPA do so because emissions from offshore sources are significant. Indeed, according to EPA's most recent greenhouse gas inventory, in petroleum systems:

> The most dominant sources of emissions, in order of magnitude, are *shallow water offshore oil platform*s, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, *deep water offshore platforms*, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas.[348]

Because VOCs are generally co-emitted with methane, especially in the production segment, offshore sources also will be significant VOC sources.

Yet, EPA neither proposes standards for offshore oil and gas production, nor justifies its failure to do so. The Clean Air Act requires EPA propose and finalize such standards.

B. Heater-Treaters

Heater-treaters, which are small boilers used to separate oil and gas emulsions, are common in both oil and gas fields, but EPA has not proposed standards for them. It must do so.

Although individual heater-treaters are relatively small sources of NO_x and CO, thousands of them are used in the production process. As the Colorado Department of Public Health and Environment explained in its recent regional haze state implementation plan, although individual heater-treaters "often fall below regulatory thresholds," there are huge numbers of such sources in use and projected for the future – 26,000 are projected by 2018 in Colorado alone.[349] As a result, heater-treaters will be the largest single area source NO_x emitters in Colorado by that year, emitting 22,901 tons per year of NOx, plus 4,809 tons per year of CO.[350]

To address these emissions, EPA has recommended voluntary use of operational standards, and numerous California air districts have set emissions standards. To wit:

- EPA recommends that operators reduce heater-treater temperatures to the minimum effective temperature. EPA notes that these combustion savings will

[348] EPA, *Inventory of U.S. Emissions and Sinks 1990-2009* (2011) at 3-49.
[349] Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011)
[350] *Id.*

reduce methane emissions by 142 Mcf per year per heater-treater, paying for themselves in fuel savings.[351]

- The San Diego County Air Pollution Control District sets emissions standards for small boilers and process heaters (with heat inputs between 600,000 BTU to 2 million BTU/hr) of 30 ppm NOx (for gaseous fuels), 40 ppm NO_x (for liquid fuel), and 400 ppm CO. .[352]

- The South Coast Air Quality Management District sets emissions standards for NOx from boilers, steam generators, and process heaters with heat inputs between 2 million and 5 million BTU. By 2008, operators were required to cut their emissions to 30 ppm NO_x (or 0.037 lb NO_x /mmBTU for gas-fired units). By 2015, emissions must fall further, to 12 ppm for atmospheric units, and 9 ppm for natural-gas fired units. CO emissions are limited to 400 ppm.[353]

- The San Joaquin Valley Air Pollution Control District sets emissions standards for small boilers, steam generators, and process heaters with heat inputs between 75,000 BTU and 2 million BTU/hr. As of January 2011, units below 400,000 BTU were limited to 0.024 lb NO_x /hr (for gas-fired units) and 0.093 lb NOx/hr (for non-gas units); larger gas units must meet the same standard, while larger non-gas units must meet a 0.036 lb NO_x /hr standard. All units are limited to a 400 ppm CO standard.[354]

- The Ventura County Air Pollution Control District's small boiler, steam generator, and process heater rules apply to units with heat inputs between 1 million and 5 million BTU/hr. Such heaters are limited to a 30 ppm NO_x standard and a 400 ppm CO standard.[355]

- The Santa Barbara County Air Pollution Control District small boilers, steam generators, and process heaters rules covers units with heat inputs between 2 million and 5 million BTU/hr. It, too, imposes a 30 ppm NO_x and 400 ppm CO standard.[356]

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[351] EPA Natural Gas STAR, *Lower Heater-Treater Temperature, PRO Fact Sheet No. 906*, attached hereto as Exhibit 119.
[352] SDCAPCD Rule 69.2.1, attached hereto as Exhibit 120
[353] SCAQMD Rule 1146.1, attached hereto as Exhibit 121.
[354] SJVAPCD Rule 4308, attached hereto as Exhibit 122.
[355] VCAPCD Rule 74.15.1. attached hereto as Exhibit 123.
[356] SBCAPCD Rule 361, attached hereto as Exhibit 124.

Controls can be imposed in various ways, running from simply lowering heater-treater temperatures and insulating units to tuning heater-treaters regularly to increase combustion efficiency, as many of the California air districts require.[357]

In short, heater-treaters are extremely numerous NO_x and CO emissions sources found throughout oil and gas fields. These emissions are readily subject to control and have been controlled, for years, by California regulators. But because each individual heater-treater's emissions will be relatively minor, heater-treaters are unlikely to be directly regulated in many states, or under federal major source permitting programs. Section 111 regulation is necessary, as a practical matter, to ensure that this cumulatively major emissions source is properly controlled.

Yet EPA fails even to recognize this facility type, much less set standards. EPA must set standards no less stringent than those employed in the California air districts (that is, at least no less stringent than the common 30 ppm NO_x and 400 ppm CO standard).

C. Field Engines and Turbines, Including Drilling Rig Engines

EPA acknowledges that "[s]ignificant emissions of [NO_x] . . . occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors through the system, and from combustion of natural gas in heaters and boilers."[358] But EPA declines to control these emissions because it asserts that these sources, though "co-located" on production sites, are "not in the Oil and Natural Gas source category" and instead are addressed by the subpart JJJJ and KKKK performance standards. EPA also, without discussion, excludes drilling rig engines from its standards. EPA does not support its decision to exclude these sources from its proposal, nor show that other standards are sufficient to control their emissions.

Emissions from this equipment have been implicated in significant air quality problems in several areas. For example, in the Pinedale Anticline supplemental environmental impact statement in Wyoming, NO_x emissions from drill rigs were estimated at 2,590 tons per year (tpy) in 2005 and 3,232 tpy in 2009 under the proposed action.[359] This represents more than six times the NO_x emissions from compression activities and 5.8 to 6.1 times the fugitive NO_x emission rates from pad construction, traffic, and completions.

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[357] *See, e.g.*, VCAPCD Rule 74.15.1 Att. 1 (describing tuning procedure); SCAQMD Rule 1146.1 Att. 1 (same).
[358] 76 Fed. Reg. at 52,756.
[359] *Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Proje*ct at 11 (Table 2.1), "Pinedale SEIS TSD," attached hereto as Exhibit 125.

NO_x emissions are a significant precursor of very harmful ozone events and of visibility impairment in nearby Class I areas. Ozone levels have exploded in the Pinedale, Wyoming area, reaching 8-hour averages of 122 parts per billion in February, 2008.[360] Emissions from natural gas production, particularly NO_x, have been implicated in these highly unusual winter-time ozone extremes.[361] Visibility impairment due to direct project source emissions has reached 45 days per year with over 1 dv of visibility impairment—6.1 dv maximum visibility impact—in 2005 in the Bridger Wilderness Area.[362]

Thus, EPA must address NO_x emissions (and emissions of other pollutants) from these sources, or demonstrate that they are sufficiently addressed by other Clean Air Act standards. It must take further action to do so, in several regards:

First, EPA must close relevant gaps in coverage of the performance standards for engines and turbines used in the oil and gas sector, such as NSPS Subparts IIII, JJJJ, and KKKK, and the non-road mobile source engine rules. One clear gap is the current exemption for turbines with heat inputs below 10 million BTU per hour.[363] These sources are plainly part of the oil and gas source category, and EPA must include them in its standards, yet it has not.

Second, as we discuss above, subparts IIII, JJJJ, and KKKK do not address all pollutants from engines and turbines used on production sites. Most notably, compressor exhaust contains significant amounts of methane,[364] which is not controlled by the subpart JJJJ and KKKK standards. These emissions will go uncontrolled unless EPA issues revised standards, perhaps in a supplemental proposal.

Third, because EPA is obligated to ensure that its review and revision of its standards for the oil and gas sector is complete, it must demonstrate on the record that all significant pollution sources from the sector have been addressed. As such, EPA must provide a clear analysis of emissions from drill rigs and other oil and gas field engines, showing (1) the types and numbers of engines that are not regulated under other provisions; (2) the emissions resulting from any gap in regulatory coverage, and (3) a description of how EPA plans to address these emissions, if it declines to promulgate standards in this

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[360] Wyoming Dept. of Enviro. Quality, (2008) "Air Pollution Advisory: Ozone For Upper Green River Basin/Sublette County," 27 February 2008. http://www.pinedaleonline.com/news/2008/02/AirPollutionAdvisory.htm, attached hereto as Exhibit 126.

[361] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415.

[362] Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Vol. 2, at 16-9 (Table 16.9) and 18-13 (Table 18.16). attached hereto as Exhibit 127.

[363] 40 CFR § 60.4305.

[364] *See supra* Section X.

rulemaking. In other words, EPA may not simply assert that these emissions are controlled elsewhere; it must demonstrate that that is the case.

IV. EPA MUST ADD STANDARDS FOR SEVERAL MISSING POLLUTANTS TO THE NSPS

EPA must regulate each dangerous pollutant emitted by sources in the oil and gas source category in more than *de minimis* quantities,[365] for which controls are available. It has failed to do so. This failure is serious: It leaves dangerous pollutants unregulated. In particular, EPA must regulate methane, particulate matter, hydrogen sulfide, and nitrogen oxides from oil and gas operations. EPA's explanation of why it declined to regulate certain pollutants does not even discuss particulate matter or hydrogen sulfide, or address the most important sources of nitrogen oxides, and does not offer a legal justification for its failure to regulate methane.

EPA's duties to regulate these pollutants arise directly from the statutory text, and from decades of agency practice.

Congress clearly intended Section 111 to address the full scope of air pollution emitted by a source category. The plain language of section 111 requires no less, repeatedly referring to the regulation of "any" air pollutant emitted by sources subject to regulation under this section. For example, Congress defined stationary sources to which NSPS apply as including facilities that emit or may emit "any air pollutant."[366] Likewise, Congress defined "modification" of existing sources – which in turn become subject to the NSPS – as "any physical change in, or change in method of operation of, a stationary source which increases the amount of *any* air pollutant emitted . . . or which results in the emission of *any* air pollutant not previously emitted."[367] That Section 111 applies to sources of "any" air pollutant is strong evidence that the Section is designed not only to *apply* to those sources but to *control* pollution resulting from "any" pollutant.[368]

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[365] Any such de minimis exemption would have to be thoroughly justified on the record; such exemptions are not routinely available.

[366] 42 U.S.C. § 7411(a)(3).

[367] *Id*. § 7411(a)(4) (emphases added).

[368] The Act provides additional evidence of Congress's intent to require EPA to establish NSPS for all pollutants emitted by a source category. Section 111(f) was inserted in response to EPA's prior challenges in promptly establishing NSPS for source categories listed under section 111(b). Under section 111(f), Congress placed EPA on a timetable to complete a specified number of delinquent NSPS by dates certain. To determine which categories should be dealt with first, Congress gave EPA three factors to consider:

> (A) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;
> (B) the extent to which *each such pollutant* may reasonably be anticipated to endanger public health or welfare; and
> (C) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new sources standards of performance

EPA must, likewise, consider "any" air pollutant emitted by a source when it reviews an existing NSPS. Section 111 provides that EPA "*shall*, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[369] Accordingly, if in EPA's judgment a category of sources "causes, or contributes significantly to" emissions that result in air pollution that may be reasonably anticipated to endanger public health or welfare, the Act requires EPA to add the category to a list, issue standards of performance applicable to that category, and review such standards on a prescribed schedule. Section 111 therefore creates an explicit, time-bound requirement for periodic review and updating of the performance standard for each category of stationary sources for all emitted air pollutants.

EPA must, in short, every eight years, (1) review its standards (as it has done here), (2) determine whether it is "appropriate" to revise them, including whether it is appropriate to add additional pollutants to the standards, and (3) if so, revise them accordingly. Again, because Congress intended EPA to reach each and any pollutant emitted by a regulated source category, this review must encompass all pollutants emitted by that source category.

EPA has long interpreted this "appropriateness" determination to turn on two (and just two) factors: (1) the amount of emissions of a given pollutant from that source category and (2) the availability of demonstrated control measures.[370,371] As EPA explained in its recent NSPS for the cement industry: "We have historically declined to propose standards for a pollutant where it is emitting in low amounts or where we determined that a BDT analysis would result in no control *National Lime Assoc'n v. EPA,* 627 F.2d at 426."[372,373] In 1985, for example, EPA decided not to revise the cement kiln standards to regulate NO_x and SO_2 emissions, based on the absence of demonstrated control technology.[374] By 2010, however, EPA found that circumstances had changed such that

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Congress thus ordered EPA to focus upon "each" pollutant emitted by these sources. Because section 111(f) standards are no different than any other NSPS – the section merely required EPA to complete unfinished standards – Congress's focus on "each" pollutant emitted by tardy sources speaks to section 111 generally, demonstrating that Congress, indeed, intended EPA's standards to control *each* pollutant emitted by such sources.

[369] *Id.* (emphasis added).

[370] *See, e.g.*, 50 Fed. Reg. 36,959, 36,961 (Sept. 10, 1985) (making negative determination based on lack of demonstrated control technology), attached hereto as Exhibit 128; 75 Fed. Reg. 54,994–95 (Sept. 9, 2010) (making positive determination based on significant emissions and existence of demonstrated control technology), attached hereto as Exhibit 129.

[371] *See also Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n. 27 (discussing these factors)

[372] 75 Fed. Reg. 54,970, 54,996-97 (Sept. 9, 2010), attached hereto as Exhibit 129

[373] *See, e.g.*, 41 Fed. Reg. 3,826, 3,827 (Jan. 26, 1976) (finding that carbon monoxide and SO_2 standards were not appropriate for aluminum smelters because technology was not demonstrated (SO_2) and emissions were insignificant (CO)), attached hereto as Exhibit 130.

[374] 50 Fed. Reg. 36,959, 36,961.

it was now appropriate to set standards for NOx and SO_2 because cement kilns emitted substantial quantities of each pollutant and demonstrated control technologies were available[375]

Thus, inherent in EPA's duty to review the oil and gas NSPS is the duty to determine, with regard to "any" air pollutant emitted by the industry, whether it was "appropriate" to regulate that pollutant. This determination, again, turns on whether the pollutant is emitted in more than *de minimis* quantities and whether control technology is available.

EPA here has failed to carry out this duty with regard to methane, particulate matter, hydrogen sulfide, and nitrogen oxides. For each of these pollutants, it has either made an unlawful decision not to regulate, or unlawfully and unreasonably omitted any consideration of the issue. It must correct these errors.

A. EPA Must Regulate Methane

1. The Clean Air Act Requires EPA to Promulgate NSPS for Methane

Methane is a potent greenhouse gas that contributes to climate change. The Supreme Court recently found that methane comes within the broad scope of the Act's definition of "air pollutant" as defined under the Act, 42 U.S.C. § 7602(g), stating: "On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through repeated use of the word 'any.'" *Massachusetts v. EPA,* 549 U.S. at 529. As a result, EPA has explicitly found that methane is a component of an air pollutant that endangers public health and welfare within the meaning of the Clean Air Act.[376]

EPA acknowledges, as it must, that the oil and gas sector "emit[s] significant amounts of methane" – the equivalent of 251.55 million metric tons of CO_2 according to EPA's most recent inventory.[377] Indeed, EPA has identified the oil and gas industry as the "single largest contributor to United States anthropogenic methane emissions."[378] These emissions make the industry the second largest stationary source of greenhouse gas pollution in the country, and the largest single industrial source of methane pollution. Control technologies for methane are readily available. EPA's decision not to regulate a major category of emissions of this potent greenhouse gas therefore is illegal.[379]

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[375] 75 Fed. Reg. 54,994–95.

[376] *Endangerment and Cause or Contribute Findings for Greenhouse Gases*, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding")

[377] 76 Fed. Reg. at 52,756.

[378] 76 Fed. Reg. at 52,792 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011)) .

[379] Though it discussed a different industry – fossil-fuel fired power plants – the Supreme Court recently recognized that the NSPS program is an appropriate mechanism for regulating CO_2, another greenhouse gas. *See AEP v. Connecticut*, 131 S.Ct. 2527, 2537-38, __ U.S. __ (2011), attached hereto as Exhibit 131, ("We think it equally plain that the Act 'speaks directly' to emissions of carbon dioxide from the defendants' plants. . . . Once EPA lists a category, the agency must establish standards of performance for

EPA offers no reasonable rationale for its failure to set standards for methane. It says only:

> Although this proposed rule does not include standards for regulating the [methane] emissions discussed above, we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.[380]

This rationale, such as it is, cannot be squared with either the statute or EPA's regulatory practice.

EPA cannot decline to complete its review duty, nor defer making an appropriateness finding. As we explain above, section 111 requires EPA to "at least every 8 years" review and, "if appropriate" revise its standards.[381] EPA must, on this review, make a final appropriateness finding, and either include methane or determine it is not appropriate to do so. It cannot delay its decision because the NSPS are designed to force pollution controls, and concomitant air quality improvements, on a statutorily-mandated timeline.

Thus, for purposes of completing its mandatory review duty as set forth above, EPA has made an affirmative decision *not* to regulate methane that both fails to apply the agency's own criteria for determining whether such a revision is appropriate, and runs directly counter to the evidence in the record. Again, EPA, as a matter of long-settled practice, has interpreted the "appropriateness" finding to turn on only two factors – the quantity of pollutant emitted and whether control technology exists to control that pollution. It cannot alter this long-standing statutory interpretation without rulemaking, and it has issued no proposal to do so. Thus, EPA is bound by its own interpretation. *See, e.g. Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 41 (1983).

On that interpretation, EPA can make only a positive appropriateness finding. The agency itself concedes that "processes in the Oil and Natural Gas source category emit significant amounts of methane." 76 Fed. Reg. at 52756. Indeed, this industry is

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emission of pollutants from new or modified sources within that category. § 7411(b)(1)(B); *see also* § 7411(a)(2). And, most relevant here, § 7411(d) then requires regulation of existing sources within the same category [unless sources of the pollutant in question are regulated under the national ambient air quality standard program, §§7408-7410, or the HAP program, § 7412].").

[380] 76 Fed. Reg. at 52,756.

[381] 42 U.S.C. § 7411(b)(1)(B).

responsible for over 40% of total U.S. methane emissions.[382] This amounts to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[383]

Moreover, in describing why it chooses not to regulate methane, EPA acknowledges that technology exists that that would enable an emission limit for methane.[384] Indeed, there are numerous demonstrated control technologies for regulating methane from the oil and gas industry that consistent BSER, many of them endorsed or developed by EPA itself through its Natural Gas STAR and Methane to Markets programs.

These control technologies not only substantially reduce emissions, but also in many cases produce profits for industry.[385] EPA has recognized that the control technologies it has proposed for VOCs will indirectly reduce baseline methane emissions for the oil and gas sector by 26%.[386] EPA also predicts industry will make $45 million annually by implementing the rules.[387] For example, EPA notes that the ability to sell natural gas captured by using the proposed equipment and work practices for "green completions" would produce a net *savings* of $99 per ton of VOC reduced.[388] Moreover, according to EPA, the climate co-benefits of the methane reductions amount to as much as $1.6 billion by 2015.[389]

Finally, EPA's statement that many of its VOC controls will also yield *de facto* methane reductions, though true, is beside the point. Not only does this assertion have nothing to do with the appropriateness factors, it also ignores the fact that methane and the VOCs which EPA *has* regulated do not overlap in ways that ensure reliable and complete methane controls. The pollutants are emitted in different ratios from various devices and sources, and so simply are not interchangeable. Further, as discussed above, some measures that EPA has rejected as having unreasonable control costs for VOC reduction, have reasonable costs when the value of methane reductions is considered.

In short: Methane is emitted in significant amounts by sources in this industry even though there is control technology readily available to reduce such emissions. Moreover, EPA has already determined that methane, an air pollutant under the Act, endangers public health and welfare.[390] Based on the plain language of section 111,

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[382] *See* 76 Fed. Reg. at 52,756, 52,791-92; *see also* EPA, Sources and Emissions/Methane, *available at* http://www.epa.gov/outreach/sources.html, attached hereto as Exhibit 132.
[383] *Id.* at 52,791–92 (citation omitted).
[384] *See* id. (explaining that some methane reduction will occur because "many of the proposed requirements for control of VOC emissions also control methane emissions").
[385] *See, e.g.*, MEGAN WILLIAMS & CINDY COPELAND, METHANE CONTROLS FOR THE OIL AND GAS PRODUCTION SECTOR at 1 (2010) (submitted to EPA under separate cover on November 23, 2010)at 1.
[386] 76 Fed. Reg. at 52,792.
[387] 76 Fed. Reg. at 52,791.
[388] 76 Fed. Reg. at 52,758.
[389] *Id.* As our discussion above indicates, these benefits may be even larger.
[390] 74 Fed. Reg. at 66,516, attached hereto as Exhibit 134.

EPA is required to include methane standards in the final rule NSPS for new and modified sources from oil and natural gas operations, as well as standards under section 111(d) for existing sources of methane within the industry.

2. EPA's Failure to Regulate Methane is Unreasonable

While section 111 requires EPA to regulate methane emissions from oil and natural gas operations, to the extent EPA possesses any discretion in the matter, its decision not to regulate methane in this rulemaking is an abuse of such discretion and must be corrected in the final rule or a supplemental rule. EPA has not attempted to justify its decision not to regulate methane emissions in the proposed rule, except to say that it "continue[s] to assess these significant emissions and evaluate appropriate actions for addressing these concerns."[391] This "justification" is not just unlawful, but unreasonable.

First, it bears repeating that EPA's standards, as proposed, fail to capture the lion's share of methane emissions from the industry. EPA estimates that co-benefit methane reductions from its rules will amount to about 26% of the industry's methane emissions.[392] The remaining 74% of methane (much, but not all, of it from existing sources) goes uncontrolled. Moreover, even the 26% reduction that EPA cites is not enforceable, as it arises only incidentally from VOC reductions.

Given the demonstrated cost-effective nature of the control technologies for regulating methane, EPA could go much further to capture a large percentage of the remaining 74% of methane emissions left on the table with this rule. As noted above, the varying ratios of VOC to methane of various devices and sources in the gas industry mean that VOC regulations cannot serve as a surrogate for methane controls. Opportunities for EPA to achieve additional methane reductions are summarized below and explained in detail in the attached report by Megan Williams and Cindy Copeland.

Moreover, failing to directly regulate methane emissions also poses serious threats to public health and welfare: Methane, as we have explained, is a potent greenhouse gas, causing climate change that will threaten public health and welfare, as EPA recognized in its Endangerment Finding. Methane contributes significantly to ozone formation.[393] In order to protect the public by ensuring substantial, enforceable methane reductions, EPA must promulgate standards to control both of these pollutants at all sources.

Finally, EPA's decision not to regulate a major category of emissions of this potent greenhouse gas is simply bad policy. Based on EPA's own estimates, the oil and gas sector within the U.S. is responsible for over 40% of the country's total methane

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[391] 76 Fed. Reg. at 52,756.
[392] *Id.* at 52,792.
[393] *See, e.g.*, *id.* at 52,791.

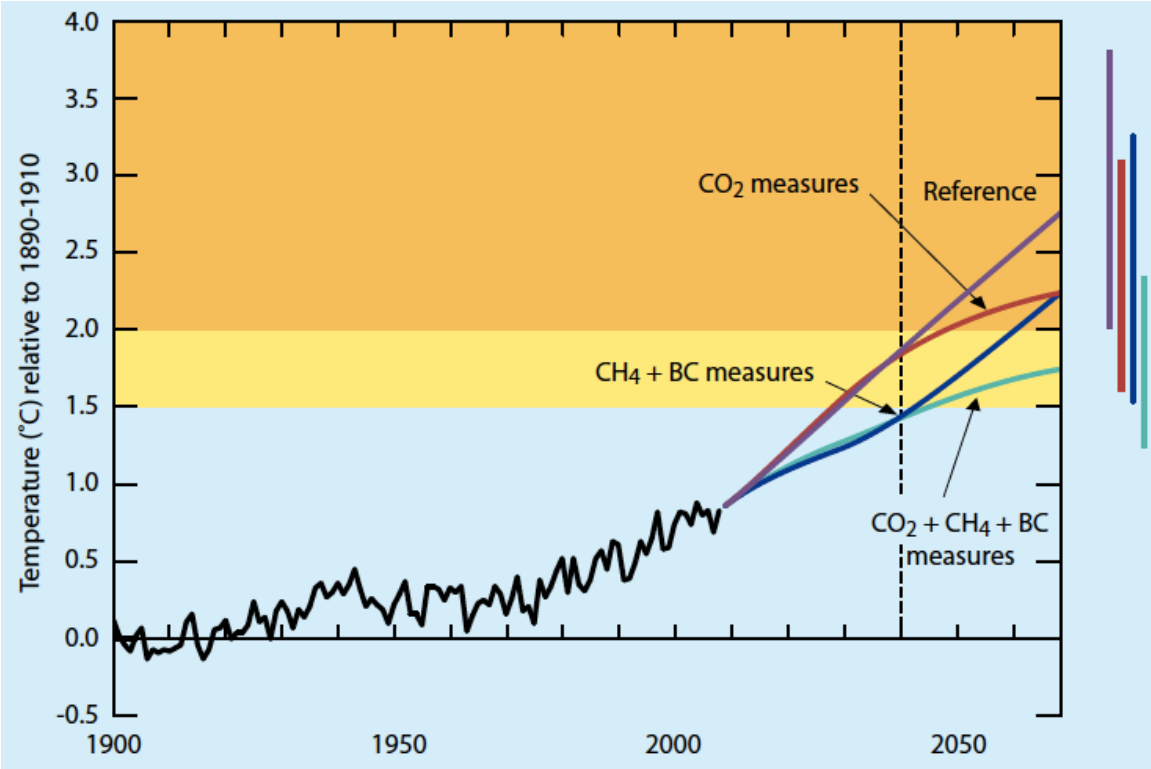
emissions.[394] Though the proposed rule will result in some reductions in methane emissions as an indirect byproduct of regulating VOC emissions, significant amounts of methane emissions will continue uncontrolled. Control technology that represents BSER within the oil and natural gas sector is available for capturing these emissions. While we commend EPA on its efforts to reduce VOC emissions, the Clean Air Act and EPA's own practices require the direct regulation of methane. The Agency's own finding that the greenhouse gas pollution of which methane is a part endangers human health and welfare demonstrates the significance of failing to regulate significant sources of methane

Methane is a potent greenhouse gas that contributes to climate change. As EPA explains in the proposed rule, "once [methane is] emitted into the atmosphere, [it] absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change."[395] Methane also reacts in the atmosphere to form ozone, which increases global temperatures.[396] Methane has 25 times the global warming potential of carbon dioxide over a 100 year time frame, and 72 times the global warming potential of carbon dioxide over a 20-year time frame.[397] The impacts of warming cause by methane and other greenhouse gases include "increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise, among other impacts."[398]

Methane's climate potency and short lifetime makes controlling methane emissions now particularly critical. While reductions of carbon dioxide emissions are essential to mitigate climate change, CO_2 *already emitted* will continue to warm the climate at dangerous rates and to dangerous levels (due to it's long lifetime in the atmosphere) if other climate warmers with shorter lifetimes are not addressed. Figure XX, from the recent UNEP report, illustrates how mitigating short-lived forcers (in this case both methane and black carbon (BC)) is an essential approach to reducing temperature rise in the coming decades. Reductions of BC and methane are essential to slow down rapid warming, *and* to reduce the peak of the warming. Conversely, if we allow methane emissions to continue to significantly increase (as they will do if the oil and gas industry is allowed to operate without a strong methane NSPS), those emissions will substantially increase the pace and severity of climate change.

Figure 5

[394] 76 Fed. Reg. at 52,756.
[395] 76 Fed. Reg. at 52,791.
[396] 76 Fed. Reg. at 52,791.
[397] IPCC 2007—The Physical Science Basis, Section 2.10.2.
[398] *Id.* at 52,791–92



Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).

Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.[399]

Methane's near term contribution to climate change is expected to have dire consequences on human health heat-related mortalities, the spread of infectious disease vectors, greater air and water pollution, and increase in malnutrition, and greater casualties from fire, storms and floods. Increased average temperatures are also expected to increase the number of heat waves.[400] This will have a particularly detrimental effect on vulnerable populations "such as those with heart problems, asthma, the elderly, the very young and the homeless."[401] Moreover, climate change is expected to play a role in worsening air quality problems that already impact human health through climate-induced increases in ozone and particulate matter levels.[402] Again, the vulnerable populations are expected to be impacted the most. Additionally,

[399] UNEP Report, Figure 3 at 12.
[400] EPA, *Climate Change, Health and Environmental Effects* (available at http://www.epa.gov/climatechange/effects/health.html) (last viewed Nov. 9, 2011)
[401] *Id*.
[402] *Id.*

the risk of contracting infectious diseases that are sensitive to climate, from malaria and yellow fever to tick-born Lyme disease, may increase with climate change.[403]

By failing to regulate methane, EPA is ignoring the recommendations of the Secretary of Energy's Advisory Board studying shale gas production. The Board recommended that regulators "expand immediately" efforts to reduce methane emissions using proven technologies.[404] The Government Accountability Office also recognized that requiring the oil and gas industry to control methane has numerous benefits, including (1) decreased greenhouse gas emissions, (2) economic benefits the industry by keeping more natural gas in the system for sale, and (3) for oil and gas development on federal lands, increased royalty payments to the federal government.[405]

B. EPA Must Regulate Particular Matter (PM)

EPA's proposed rule also fails to establish limits on particulate matter pollution from oil and gas development. Particulate matter is a "criteria pollutant" known to endanger public health and welfare. As discussed above, EPA has long evaluated whether it is "appropriate" to revise new source performance standards to include new pollutants based on (1) the amount of emissions from that source category, and (2) the availability of demonstrated control measures.[406] Both factors dictate regulation with respect to particulate matter from oil and gas development.[407] Yet, EPA does not even offer a rationale for failing to regulate this pollutant.

The first factor dictates regulation because oil and gas development is a major source of particulate matter. Particulate matter is produced during every phase of a drilling project. During road and well pad construction, particulate matter is generated by "equipment producing fugitive dust while moving and leveling earth" and by "vehicles generating fugitive dust on access roads."[408] Wind also kicks up particulate matter from

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[403] *Id.*

[404] SEAB Interim 90-Day Report, at 2.

[405] Government Accountability Office, "Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions," *Report to the Honorable Jeff Bingaman, Ranking Minority Member, Committee on Energy and Natural Resources, U.S. Senate*, July 14, 2004, attached hereto as Exhibit 135.

[406] *See, e.g.*, *Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n.27.

[407] Section 111 applies broadly to categories of stationary sources including "any building, structure, facility, or installation which emits or may emit any air pollutant." 42 U.S.C. § 7411(a)(3). As the D.C. Circuit has recognized, this may include emissions from roads that are "constituent parts" of a stationary source. *See Ala. Power Co. v. Costle*, 606 F.2d 1068, 1079 (D.C. Cir. 1979), *superseded by Ala. Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), attached hereto as Exhibit 136. In this case, EPA has defined the oil and natural gas sector broadly to include all "operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas." 76 Fed. Reg. at 52,744. Particulate matter pollution from construction of roads and well pads and vehicle trips necessary to drill for oil and natural gas and produce and distribute natural gas are encompassed within this definition.

[408] West Tavaputs FEIS at 4-16 to 4-17; *see also* BLM, *Revised Near-Field Air Quality Technical Support Document for the GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental*

well pads, dirt roads, and other disturbed areas susceptible to erosion.[409] Drilling and completion activities and subsequent well operations also require significant vehicle traffic, which generates additional particulate matter.[410] For example, trucks are necessary to transport fracking fluids, produced condensate, and water from storage tanks.[411] A 2008 study by the Utah Department of Transportation ("UDOT") estimated a range of 375 to 1,375 truck trips per well, depending on the depth of the well and its location.[412] That translated to 7,585 truck trips per day in the Uinta Basin during 2005-2006.[413] Similarly, in 2006, BLM predicted 851 round-trip truck trips for drilling and operation of each of the 3,100 wells approved by the Jonah Infill Drilling Project in Wyoming.[414]

Construction of wells and roads and vehicle traffic leads to considerable particulate matter pollution. For example, BLM estimates that natural gas operations on the West Tavaputs Plateau will generate more than 8,000 tons of fugitive dust each year from construction, drilling, and development activities and more than more than 1,800 tons each year from operations activities.[415] For the Gasco Energy Inc. Project in the Uinta Basin in Utah BLM estimates emissions of more than 4,000 tons of particulate matter each year.[416] In fact, road traffic associated with the extensive oil and gas development in Uinta County, Utah is expected to push PM_{10} concentrations to 99.7% of the NAAQS standard.[417]

The second factor relevant to EPA's determination whether to establish a standard of performance for particulate matter is also met because there are numerous methods

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Impact Statement, at 9, 17 (Apr. 2010) ("GASCO TSD") ("The major pollutant associated with development activities would be PM_{10} and $PM_{2.5}$ generated by earth-moving and traffic activities."), attached hereto as Exhibit 137; BLM, *Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil & Gas Exploration & Development Project*, at 4-74 (June 2008) ("Pinedale Anticline SEIS") (noting that particulate matter pollution would be produced by earthmoving equipment and vehicle traffic fugitive dust)

[409] *See, e.g.*, *Air Quality Impact Analysis Technical Support Document for the Pinedale Anticline SEIS*, at 9-11 (June 2008) (noting that substantial PM_{10} and $PM_{2.5}$ emissions would occur from construction of well pads and roads, traffic, and wind erosion)

[410] *See, e.g.*, *West Tavaputs FEIS* at 4-16 to 4-17.

[411] *See, e.g.*, *id.*

[412] *See* ENVIRON, *Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report*, at 3-7 (June 2010) ("ENVIRON Report") (reviewing and summarizing UDOT's 2008 study, *Highway Freight Traffic Associated with Development of Oil and Gas Wells*), attached hereto as Exhibit 138

[413] *Id.* at 7.

[414] *Id.* at 19 (summarizing BLM's 2006 Jonah Infill Drilling Project Environmental Impact Statement).

[415] *See Near-Field Air Quality Technical Support Document for the West Tavaputs EIS*, at 44, 70 ("West Tavaputs TSD"), attached hereto as Exhibit 139.

[416] *GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement*, at 4-7 (Oct. 2010) ("GASCO DEIS"); *see also* ENVIRON Report, at 19 (noting that for the Jonah Infill Drilling Project BLM predicted nearly 4,000 pounds of fugitive PM_{10} per well from the unpaved road traffic necessary just for well completion testing); *id.* at 35 (noting that for drilling in the Little Snake Resource Management Area in Colorado BLM predicted tens of thousands of pounds of particulate matter from the traffic associated with each well pad or project).

[417] *See GASCO DEIS* at 4-27.

available to significantly reduce fugitive dust emissions. For example, application of water or other dust suppressants limits the amount of fugitive dust produced during construction and by vehicle traffic.[418] Watering haul roads can reduce particulate matter emissions by up to 95% during the first half hour after watering and by 74% during the three-to-four hours following watering.[419] Speed and traffic restrictions can also reduce particulate matter pollution from oil and gas vehicles.[420] Other control methods include minimizing road networks by clustering development, and designing and constructing roads with surface materials, drainage, and other characteristics to reduce erosion and sources of fugitive dust.[421] Prompt reclamation and vegetative surfacing of disturbed areas can further limit sources of fugitive dust.[422]

Given the significant amounts of particulate pollution from various stages of oil and gas development and the controls available to limit that pollution, the EPA must promulgate a new source performance standard pursuant to Section 111. EPA has established methods for estimating particulate matter emissions associated with oil and gas development, and could set control efficiencies for those emissions.[423] At a minimum, EPA must establish work practice standards that "reflect the best technological system of continuous emission reduction . . . adequately demonstrated."[424] For example, work practice standards could include requirements for operators to prepare a fugitive dust plan and mandate available control methods for the construction, use, and maintenance

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[418] *See* W.R. Reed & J.A. Organiscak, *Haul Road Dust Control: Fugitive Dust Characteristics from Surface Mine Haul Roads and Methods of Control*, at 4 (Oct. 2007) ("The use of water on haul roads is the most common dust control method used."), attached hereto as Exhibit 140; *see also* EPA, *AP-42: Compilation of Air Pollutant Emission Factors*, Ch. 13.2.2 at 10 (Nov. 2006) ("EPA AP-42") (wet suppression and other forms of surface treatments "increase[] the moisture content, which conglomerates particles and reduces their likelihood to become suspended when vehicles pass over the surface"), attached hereto as Exhibit 141; BLM, *Atlantic Rim Natural Gas Development Project Record of Decision*, at B-5 to B-6 (Mar. 2007) ("Atlantic Rim ROD") (operators required to apply water for dust abatement), attached hereto as Exhibit 142.

[419] *See* Reed & Organiscak, at 4.

[420] *See* EPA AP-42, Ch. 13.2.2 at 8 (vehicle restrictions to control fugitive dust include "lower[ing] the mean vehicle speed"); BLM, *Jonah Infill Drilling Project Record of Decision*, at B-16 (2006) ("Jonah Infill ROD") (requiring contractors and employees to obey speed limits, in part, to reduce fugitive dust concerns), attached hereto as Exhibit 143.

[421] *See, e.g.*, *Jonah Infill ROD* at B-14, B-16 (operators to conduct transportation planning "to identify the minimum road network necessary" and centralize infrastructure and operations); *Atlantic Rim ROD* at B-5 to B-6 (operators to control fugitive dust by "us[ing] appropriate road design including shape, drainage, and surface material to project road bed from being eroded"); AP-42, Ch. 13.2.2 at 10 (describing surface improvements that permanently alter the road surface to reduce fugitive dust emissions).

[422] *See, e.g.*, *Jonah Infill ROD* at B-17 (operators to expeditiously "establish plant cover" for disturbed areas).

[423] *See, e.g.,* AP-42, Ch. 13.2.2 at 4 (EPA equation for estimating fugitive dust emissions per vehicle mile travelled on unpaved surfaces based on surface material silt and moisture content, and mean vehicle weight and speed); BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Record of Decision*, Att. 2 at 36 (July 2010) (condition of approval requiring a minimum of 50% control efficiency for particulate matter from well pad and road construction).

[424] *See* 42 U.S.C. § 7411(h)(1).

of all access roads and well pads.[425] Notably, any standard for application of chemical dust suppressants would require the EPA to assess associated "non-air quality health and environmental impact[s]."[426]

C. EPA Must Regulate Hydrogen Sulfide (H_2S)

Hydrogen sulfide (H_2S) is an extremely dangerous air pollutant which is emitted in significant quantities from the oil and gas industry. Although EPA has issued other Section 111 standards controlling H_2S, and control technologies are available to manage its emissions, EPA has failed to include H_2S in its proposed NSPS, or even to discuss the matter. It must correct this error.

1. Background on H_2S Exposure and Toxicity

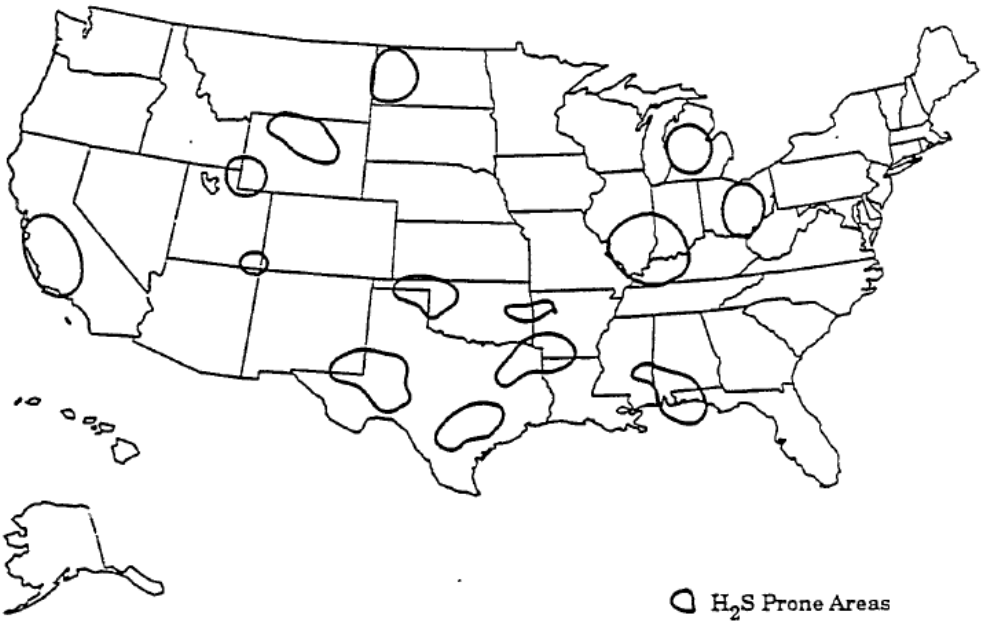
According to EPA, "H_2S is the most common impurity in hydrocarbon gases," and there are at least "14 major H_2S prone areas found in 20 states," including some fields where H_2S is 42% (by volume) of the gas produced.[427] The problem is national in scope, as this the figure below, taken from EPA's own report, demonstrates:

Figure 6

[425] *See, e.g.*, 74 Fed. Reg. 25,312-13 (May 27, 2009) (proposing work-practice standards for roads within coal-preparation operations, including a requirement for "fugitive dust plan[s]" that "require the owner/operator to pave the roads, wet the road surface, sweep up excess coal dust, or install tire washes to remove entrained dust to control PM emissions").

[426] 42 U.S.C. § 7411(h)(1). EPA's own internal report on chemical dust suppressants identifies several potential impacts, such as impacts to surface and groundwater quality, soil contamination, and toxicity to humans. Thomas Piechota et al., *Potential Environmental Impacts of Dust Suppressants: "Avoiding Another Times Beach,"* at v (2002), attached hereto as Exhibit 144. The report warns that chemical suppressants "should be avoided near sensitive environments, near water bodies and fractured rock, in areas with a shallow groundwater table, and other areas where water could quickly reach the saturation zone" and that "[s]ite specific characteristics should be considered when approving the use of dust suppressants." *Id.* at 17.

[427] *EPA Hydrogen Sulfide Report* at ii.



Source: Gas Research Institute. 1990.

Figure II-1. Major H_2S prone areas.

"Between 15 and 25 percent of natural gas in the U.S. may contain hydrogen sulfide."[428] There is substantial overlap between H_2S-prone areas and active oil and gas plays, meaning, according to EPA, that, with hundreds of thousands of wells at least potentially implicated in H_2S emissions, "the potential for routine H_2S emissions is significant."[429]

This potential is extremely concerning because hydrogen sulfide is toxic even at very low concentrations. The Agency for Toxic Substances and Disease Registry (ATSDR) has established a "minimal risk level" (MRL) – an "estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects" – of 0.07 ppm for acute inhalation exposure to H_2S. ATSDR's intermediate-duration inhalation MRL is 0.02 ppm. EPA, similarly, calculated a chronic reference concentration (RfC) – the threshold below which it would not expect deleterious effects over a lifetime of daily exposure – of 0.001 ppm (that is, 1 part per billion, or "ppb") [430] There is substantial evidence that long-term low-level exposure can cause significant community health problems. As one researcher summarized, these long-term effects are substantial, and are particularly severe in children:

[428] Skrtic Report at 6 (May 2006).
[429] EPA Hydrogen Sulfide Report at III-35.
[430] ATSDR, *Toxicological Profile for Hydrogen Sulfide* at 14, 153 (2006), attached hereto as Exhibit 145.

Kilburn and Warshaw (1995) investigated whether people exposed to sulfide gases, including H2S, as a result of working at or living downwind from the processing of "sour" crude oil demonstrated persistent neurobehavioral dysfunction. They studied 13 former workers and 22 neighbors of a California coastal oil refinery who complained of headaches, nausea, vomiting, depression, personality changes, nosebleeds, and breathing difficulties. Neurobehavioral functions and a profile of mood states were compared to 32 controls matched for age and educational level. The exposed subjects' mean values were statistically significantly different (abnormal) compared to controls for several tests (two-choice reaction time; balance (as speed of sway); color discrimination; digit symbol; trail-making A and B; immediate recall of a story). Their profile of mood states (POMS) scores were much higher than those of controls. Test scores for anger, confusion, depression, tension-anxiety, and fatigue were significantly elevated and nearly identical in both exposed residents and former workers, while the scores for controls equaled normal values from other published studies. Visual recall was significantly impaired in neighbors, but not in the former workers. Limited off-site air monitoring (one week) in the neighborhood found average levels of 10 ppb H2S (with peaks of 100 ppb), 4 ppb, dimethylsulfide, and 2 ppb mercaptans. On-site levels were much higher. The authors concluded that neurophysiological abnormalities were associated with exposure to reduced sulfur gases, including H2S from crude oil desulfurization…..

In a case report Gaitonde *et al*. (1987) described subacute encephalopathy, ataxia, and choreoathetoid (jerky, involuntary) responses in a 20-month-old child with long term (approximately one year) exposure to hydrogen sulfide from a coal mine. Levels of up to at least 0.6 ppm (600 ppb) were measured and levels were possibly higher before measurements started. The abnormalities resolved after the emission source ceased operation.

As part of the South Karelia Air Pollution Study in Finland (Jaakkola *et al*., 1990), Marttila *et al*. (1994) assessed the role of long-term exposure to ambient air malodorous sulfur compounds released from pulp mills as a determinant of eye and respiratory symptoms and headache in children. The parents of 134 children living in severely polluted (n = 42), moderately polluted (n = 62), and rural, non-polluted (n = 30) communities responded to a cross-sectional questionnaire (response rate = 83%). In the severely polluted area, the annual mean concentrations of hydrogen sulfide and methyl mercaptan (H3CSH) were estimate to be 8 µg/m3 (6 ppb) and 2 - 5 µg/m3 (1.4 – 3.6 ppb), respectively. The highest daily average concentrations were 100 µg/m3 (71 ppb) and 50 µg/m3 (36 ppb), respectively. The adjusted odds ratios (OR) for symptoms experienced during the previous 4 weeks and 12 months in the severely versus the non-polluted community were estimated in logistic regression analysis controlling for age and gender. The risks of nasal symptoms, cough, eye symptoms, and headache were increased in the severely polluted community, but did not reach statistical

> significance…. In addition, OEHHA staff noted that the highest percentages of children with symptoms were in the moderately polluted community, not in the severely polluted community. The authors concluded that exposure to malodorous sulfur compounds may affect the health of children. The odor threshold for methyl mercaptan of 1.6 ppb (Amoore and Hautala, 1983) indicates that it also likely contributed to the odor and probably the symptoms.[431]

The oil and gas industry offers ample opportunities for such exposures, as EPA explained in its 1993 study of its H_2S emissions:

> In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline), and refining. . . . Potential sources of emissions include flares/vapor incinerators, heater-treaters (an oil/water/gas separation device), storage tanks, equipment (valves, flanges, etc.), and both active and abandoned wells.[432]

Although direct monitoring data of H_2S emissions around oil and gas extraction sources is limited, the data that does exist suggest that these sources are substantial. North Dakota, for instance, reported 3,300 violations of an odor-based H_2S ambient air quality standard around wells in that state, likely due to incomplete combustion of H_2S in wellhead flares.[433] Community monitoring in 2011 around gas wells in the Four Corners region of New Mexico and Colorado, likewise detected H_2S in one sample at levels 185 times safe levels.[434]

2. EPA Must Regulate H_2S Under Sections 112 of the Clean Air Act, or, at the very least, Section 111

In view of these risks, EPA must use its Clean Air Act authority to control H_2S emissions from the oil and gas industry.

At present, EPA makes only limited use of that authority. Although H_2S is controlled from major sources under the Prevention of Significant Deterioration program, the oil and gas industry is otherwise largely regulated only to prevent large-scale, emergency releases of H_2S, under Section 112(r) of the Clean Air Act, 42 U.S.C. § 7412(r). This provision focuses on efforts to "prevent the accidental release" of H_2S, and is not a substitute for baseline technological standards, applicable to all sources in the industry, and designed to prevent *ambient*, and long-term exposures to lower levels of this pollutant.

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[431] James Collins & David Lewis, Report to CARB, *Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protection of Children* (Sept. 1, 2000).
[432] *EPA Hydrogen Sulfide Report* at ii; *see also id.* at II-5 – II-11 (listing sources).
[433] *Id. at* III-35.
[434] Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development* at 21

Ultimately, H_2S must be re-listed as a hazardous air pollutant ("HAP") under Section 112 of the Act, and controlled under its standards. [435] Several of the commenting groups have so petitioned EPA, and EPA staff has independently recommended that result, writing that:

- [The EPA OAQPS] Workgroup recommends listing because:
  - H_2S emission tonnage would rank among highest of HAPs
  - In terms of toxic potency, H_2S would rank in the top third of HAPs
  - Both ambient monitoring and modeled exposures show significant exceedances of health benchmarks, chronic and acute
  - Investigations of multiple complaints have demonstrated adverse health effects associated with exceedances of health benchmarks
  - If listed, H_2S would likely rank among top 6 noncarcinogens in [the National-Scale Air Toxics Assessment]
- In combination, these data suggest a "reasonable" likelihood that H2S presents a threat of adverse human health effects for both chronic and acute exposures, and meets the requirements under 112(b)(2) to list.[436]

To date, EPA has not taken action on either this recommendation or upon the petitions before it. In the absence of such action, it is appropriate, and, indeed, necessary, for EPA to control H_2S under the Section 111 program, which, though not as well-suited as Section 112 for the task, is available and can be used immediately. By accepting as much, we of course do not abandon our continued view that Section 112 regulation is ultimately necessary.

H_2S meets both "appropriateness" criteria under Section 111. First, as described above, it is emitted in substantial quantities from the oil and gas industry, in fields across the country.[437] Second, control technologies are readily available, and are in use in the oil and gas industry. Vendors offer, for instance, membrane-based removal systems,[438] a

[435] Hydrogen sulfide was removed from the section 112 list, without explanation, by Congress after significant industry pressure; its removal continues to put public health and welfare at unacceptable risk. Nothing prevent EPA from correcting this problem by re-listing hydrogen sulfide.

[436] EPA OAQPS Sector Based Assessment Group, *Should Hydrogen Sulfide be a HAP?* at 23 (Sept. 2007), attached hereto as Exhibit 146.

[437] Significantly, in this regard, state regulations are not uniformly or adequately limiting these emissions. As EPA staff recently summarized, state rules are highly variable, and many states (including major oil and gas producers like Louisana, and states containing important new plays, like Ohio, lack H_2S standards entirely). *See id.* at 16. Although the presence or absence of state regulation does not bear on EPA's Section 111 regulations, it is notable that exposure risks are going uncontrolled in many regions at both the state and federal levels, and underlines the unreasonableness of EPA's failure to act.

[438] Membrane Technology and Removal, H_2S Removal from Natural Gas: Soursep (vendor offering wellhead bulk removal system), attached hereto as Exhibit 147.

wide range of amine-based removal systems to scavenge H_2S at wells and in tanks,[439] and compounds designed to prevent bacteria from producing H_2S.[440]

EPA moreover has demonstrated that it can regulate H_2S emissions from a wide range of sources under Section 111. EPA has promulgated several NSPSs which control either H_2S or "total reduced sulfur" (a catchall term that includes H_2S) including for pulp and paper mills and petroleum refineries – but not for gas processing plants or oil and gas production. The most significant of these standards are the Subpart J and Ja standards, which control emissions from new and modified petroleum refineries. EPA's sulfur standards bar flaring any fuel gas which contains more than 230 mg/dscm of H_2S, as a sulfur oxide control measure, 40 C.F.R. § 60.104(a)(1), and bars emissions of any gas from Claus sulfur recovery plants which is more than 300 ppm by volume of reduced sulfur compounds or more than 10 ppm H_2S.[441] The standards also require periodic H_2S monitoring.[442] Yet, the NSPS program does not control H_2S from oil and gas sector sources.

It is time for EPA to correct this omission. Because both Section 111 appropriateness factors are met, EPA must propose, and then finalize, H_2S standards covering each H_2S source in the oil and gas sector.

To the extent EPA believes it requires more data to issue such standards, it must issue a Section 114 information collection request gathering data from the industry. This information request is particularly important because much of our information about the industry's emissions is rooted in EPA's 1993 report to Congress on H_2S. That report was drafted long before the shale gas boom saw the industry expand substantially, including into many urban and heavily-settled semi-rural areas. Now, wells are being built throughout the Dallas-Forth Worth area, for instance, as well as in and around cities in Pennsylvania. Properly assessing the health impacts of this increasing interweaving of oil and gas development with dense settlement is critical to accurately understanding H_2S exposure risks. EPA must properly assess these risks, and, in view of these changed circumstances, cannot rely upon its earlier assessments to assert that ambient exposure to H_2S is limited. Without waiving any claim that EPA was required to collect such information in the context of this rulemaking in order to timely complete its review duties, we ask that EPA state, in the final rule, whether and when it will issue such an information collection request.

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[439] Weatherford, *Hydrogen Sulfide Control* (vendor offering amine-based removal system), attached hereto as Exhibit 148; Baker Hughes, *White Paper: Hydrogen Sulfide Management: Mitigation Options in Petroleum Refining, Storage, and Transportation* (discussing a wide range of solutions for reducing H_2S formation and venting in tanks), attached hereto as Exhibit 149

[440] Yara United States, *PetroCare* (vendor offering chemical compounds for use in well construction to prevent H_2S formation), attached hereto as Exhibit 150.

[441] 40 C.F.R. § 60.104(a)(2); 40 C.F.R. § 60.102a(f)(1)(ii).

[442] 40 C.F.R. 60.105(f).

D. EPA Must Regulate Nitrogen Oxides (NO_x)

As we discuss above, certain oil- and gas-field combustion sources, including heater-treaters, are major NO_x emissions sources. Heater-treaters, in fact, may become dominant NO_x emissions sources in many regions, because they are so numerous. EPA must regulate this source, and, hence, must regulate this pollutant.

Once again, it is "appropriate" to do so under Section 111. As we discuss above, heater-treaters emit significant amounts of NO_x, and these emissions are controllable. As a result, EPA must include appropriate NO_x regulations in the final rule.

V. EPA MUST REGULATE METHANE AND VOCS FROM EXISTING SOURCES

Although the emissions reductions secured by EPA's proposal are significant, they represent only a relatively small fraction of the industry's total air pollution, because they do not address the extensive network of existing sources. As a result, as we note above, EPA is capturing only about 26% of the total methane emissions from the industry, and is likely capturing roughly similar percentages of the VOC emissions.[443] Although the proposed NSPS achieves significant VOC reductions from new and modified sources, it fails to control emissions from non-well existing sources, aside from refractured wells, even though these emissions are substantial. EPA must issue standards under section 111(d) of the Clean Air Act to control these emissions.

Unless these existing sources are regulated, the industry will continue to be a major source of significant air pollution for years to come. For this reason, the Secretary of Energy's Advisory Board Shale Gas Production Subcommittee, charged by the President with developing recommendations to control the industry's impacts, directly called on EPA to regulate existing sources in this rulemaking, writing:

> On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. *However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.*[444]

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[443] *See* 76 Fed. Reg. at 52,792.

[444] Shale Gas Production Subcommittee Second 90-Day Report (Nov. 18, 2011) at 5 (emphasis added), attached hereto as Exhibit 151.

EPA must correct this crucial gap. It is required to do so by statute, for both methane and VOC sources, as we explain below. Because much pollution from existing sources can be controlled using variations of the same methods EPA has already proposed for new sources in this rulemaking, such existing source standards can be developed and implemented quickly. After setting out EPA's legal obligations, we describe how such standards can and must be designed.[445]

A. EPA Must Regulate Existing Sources of Methane

We have already described why EPA must regulate methane from new and modified sources under Section 111(b): It is an abundant (indeed, the most abundant) pollutant from the oil and gas industry, and is readily controlled with available technology. Once EPA promulgates such new and modified source standards, it will be required to control existing sources as well, under Section 111(d) of the Act.

Section 111(d) of the Act provides that EPA "shall prescribe regulations" which establish a process, mirroring that for State Implementation Plans pursuant to section 110, under which states establish standards of performance for existing sources that emit certain pollutants.[446] These pollutants, referred to as "designated pollutants," 40 C.F.R. § 60.21(a) include:

> Any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[447]

Methane will be such a "designated pollutant" as soon as EPA issues 111(b) standards controlling it. This is because methane is, first, not a criteria pollutant (that is, it is not "on a list published under section 7408(a)" and EPA has not issued an air quality standard for it). Nor is methane a critical air pollutant "regulated under section 7412."[448] As a result, once "a standard of performance under this section" is

[445] We note the proposal does apply to some existing sources through its modification provisions. Specifically, we applaud EPA's proposal to define the completion and recompletion of a hydraulically fractured gas well as a modification. It appears from the preamble that other existing sources, including pneumatic controllers and centrifugal compressors, are also subject to the new source performance standards, in a manner of speaking, in that the NSPS dictates how they must be replaced. 76 Fed. Reg. at 52738, 52761-62. We agree that replacement of an existing source constitutes new construction and therefore requires compliance with the NSPS. The final rule language must clarify that replacement of any and all affected facilities triggers compliance with the NSPS.

[446] 42 U.S.C. § 7411(d)(1).

[447] 42 U.S.C. § 7411(d)(1).

[448] Although the statute refers to pollutants "emitted from a source category which is regulated under section 7412," EPA has made clear in its rules that this restriction on 111(d) applicability applies to

promulgated for the industry, regulating methane, methane will also be subject to Section 111(d) regulation.

Such regulation is implemented via a state-implementation-plan like process "under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source" of a designated air pollutant.[449] To speed this process, EPA sets forth standards of performance for these pollutants covering existing sources in "emission guidelines," which the states must then adopt.[450] Emission guidelines specify how the states shall reduce air pollution from existing sources that emit certain air pollutants to which a standard of performance would apply if such existing source were a new source.[451]

Like standards of performance for new sources, emission guidelines must reflect "Best Demonstrated Technology" and the "Best System of Emissions Reduction."[452] Emission guidelines can be tailored to the remaining useful life, of existing sources, as well as other relevant factors.[453] EPA "shall" issue such emissions guidelines for pollutants that are neither hazardous air pollutants listed under section 112 nor criteria pollutants listed under section 108.[454]

This process moves forward once EPA has promulgated Section 111(b) standards. EPA rules provide that "*[c]oncurrently* upon or after proposal of standards of performance for the control of a designated pollutant [from sources subject to an NSPS]," EPA "*will* publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities [existing sources]," and "a final guideline document *will be published*" "*upon or after*" promulgation of standards of performance for new sources.[455]

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pollutants listed under Section 112, not every pollutant emitted from a Section 112 source category (as some of these pollutants may not be listed HAPs, but will still warrant control under other programs).

[449] 42 U.S.C. § 7411(d)(1).

[450] *See* 40 C.F.R. §§ 60.21(e) and 60.22.

[451] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.21(b) (defining facilities to which emission guidelines apply as those "which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility").

[452] 40 C.F.R. § 60.22(b)(5) (providing that guideline documents "will" include "an emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities…"). *See also* 40 C.F.R. § 60.21(e) ("Emission guideline means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator determines has been adequately demonstrated for designated facilities.")). Of course, in situations where EPA has set a section 111(h) BTSER standard, existing source regulations must parallel this standard as well.

[453] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.22(b) (describing content of emission guidelines).

[454] *See* 42 U.S.C. § 7411(d)(1).

[455] 40 C.F.R. § 60.22(a) (emphases added).

Thus, EPA regulation of new and modified sources will trigger regulation of existing sources. This process will take time. Once a guideline document has been published, the states generally have nine months to submit their plans,[456] and the plans themselves may not become effective immediately for all sources. The longer EPA delays even proposing *new* source standards, the longer it will take to complete the existing source process, during which time approximately three-quarters of the industry's methane emissions will continue to go uncontrolled. EPA therefore must begin the process as soon as possible in order to timely address this major emissions source.

B. EPA Must Regulate Existing Sources of VOCs

Like methane, VOCs are "designated pollutants" for Section 111(d) purposes and EPA must promulgate existing source standards for them.

VOCs are designated pollutants because they are neither criteria pollutants nor hazardous air pollutants. For NSPS purposes, "Volatile Organic Compound" means, simply, "any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an alternative method, or which is determined by procedures specified under any subpart."[457] There are no 42 U.S.C. § 7408 criteria for VOCs so defined, and VOCs are not listed as section 112 HAPs.[458] Moreover, when EPA finalizes its current proposal, VOCs will be "subject to a standard of performance for new stationary sources" in the oil and gas industry.[459] As such, the plain language of the statute, and of EPA's implementing regulations,[460] renders VOCs designated pollutants.

Thus, once EPA finalizes its 111(b) standards, it must immediately move on to proposing and finalizing 111(d) standards for existing VOC sources.[461] Although the regulations provide that EPA must act "concurrently or thereafter," we urge EPA to offer proposed guidelines simultaneously with its final new source standards, to ensure that the process to control this major pollution source moves forward rapidly, and to provide the industry with a clear regulatory calendar.

Such progress is particularly important because existing facilities are such significant VOC sources. Although new and modified VOC sources emit a total of 2.24 million tons of VOC per year,[462] and, according to EPA, the proposed NSPS and NESHAP, acting

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[456] 40 C.F.R. § 60.23
[457] 40 C.F.R. § 60.2; *see also* Proposed 40 C.F.R. § 60.5430 (adopting the definitions in § 60.2 and in Subpart VVa); 40 C.F.R. § 60.481a (Subpart VVa, adopting the § 60.2 definition).
[458] *See* 42 U.S.C. § 7412(b)(1) (HAP list)
[459] See 40 C.F.R. § 60.21(a).
[460] *See* 40 C.F.R. § 60.21(a),
[461] 40 C.F.R. § 60.22(a).
[462] RIA at 3-1.

together, will reduce VOC emissions from these sources by 540,000 tons of VOC or more in 2015,[463] but existing sources account for a substantial portion of the remaining VOC inventory. While EPA does not include an estimate of the total amount of emissions from existing sources in the proposed rulemaking, estimates from others demonstrate such emissions are substantial. As Table 2 demonstrates, VOCs from existing sources in five basins in the Intermountain West are projected to equal 259,051 tons in 2012.[464] Without regulation to reduce emissions from existing equipment, these emissions will continue for many years.

Table 2

Oil & gas emissions source	**Denver-Julesburg basin**		**Uinta basin**		**Piceance basin**		**North San Juan basin**		**South San Juan basin**		**Wind River basin**	
VOC	2006	2010	2006	2012	2006	2012	2006	2012	2006	2012	2006	2012
Condensate tanks	53,510	53,109	6,195	21,719	3,405	1,895	0	0	3,964	3,790	710	519
Oil tanks	0	0	14,357	20,722	0	0	165	165	2,430	2,359	449	486
Dehydrators	506	332	19,470	30,665	2,929	2,371	14	10	11,372	10,896	1,324	1,010
Well blowdowns	1,744	2,207	292	460	2,172	2,444	0	0	13,145	12,595	2,018	1,861
Fugitives	8,024	10,498	1,910	3,212	1,330	1,871	0	0	4,137	4,631	296	415
Pneumatic devices & pumps	12,381	16,342	23,301	39,404	2,532	3,835	0	0	1,726	1,925	6,351	7,303

In short, if EPA developed standards for existing sources it would achieve substantial health and environmental benefits. It must do so.

We recognize, of course, that VOCs are also treated as ozone precursors, and that ozone is a criteria pollutant, which could not itself be regulated under Section 111(d). Although they are not defined as precursors for NSPS purposes, EPA's regulations governing the Prevention of Significant Deterioration program,[465] and those governing state implementation plans,[466] do so define them. Ozone is generally regulated

[463] 76 Fed. Reg. at 52,791.
[464] Western Regional Air Partnership Phase III *2006 and 2012 Activity Emission Estimates for the Denver-Julesburg, Piceance, Uinta, South San Juan, North San Juan, and Wind River Basins*, available at http://www.wrapair.org/forums/ogwg/PhaseIII_Inventory.html, attached hereto as Exhibit 152.
[465] *See* 40 C.F.R. §§ 51.15(a)(1)(xxxvii)(c)(1), 51.166(b)(49)(i), 52.21(b)(50)(i)(A).
[466] *See* 40 C.F.R. § 51.100(s)

primarily through state implementation plans implementing the National Ambient Air Quality Standards (NAAQS) for ozone, as directed by Section 108 of the Act and by the special ozone regulatory program in subpart 2 of part D of the Act, addressing ozone nonattainment areas.[467]

Although some commenters may argue that this precursor status precludes section 111(d) regulation of VOCs, this is not the case. Initially, as a purely textual matter, the statute simply does not refer to "precursors" to criteria pollutants themselves as included in the Section 111(d) ban. Nor do EPA's implementing regulations. So, to the extent that EPA has any authority to decline regulation of VOCs as 111(d) pollutants, that authority does not arise from section 111(d).

If EPA claims such authority, it could be found only in section 302, which provides that the term "air pollutant":

> [I]ncludes any precursors to the formation of any air pollutant, *to the extent* the Administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used.[468]

Put differently, section 302, if anything, grants EPA the discretion to identify particular precursors and incorporate those substances into the definition of an "air pollutant" for particular regulatory purposes.

EPA has used this discretion previously. In a series of rulemakings implementing the PM 2.5 NAAQS, it explained that it would treat each PM 2.5 precursor distinctly for regulatory purposes because "the Administrator has discretion to identify which pollutants must be classified as precursors for particular regulatory purposes."[469]

Thus, nothing about section 302 obligates EPA to decline to regulate VOCs under section 111(d). On the contrary: section 302 authorizes EPA to identify distinct "particular purpose[s]" in its various regulatory definitions of precursor pollutants. The agency therefore need not treat VOCs the same way for section 111(d) regulation as it does for ozone NAAQS regulation, because in each instance, the regulations "address different aspects of the air pollution problem" caused by VOCs. Specifically, although sections 108 and 182 of the Act requires state implementation plans to include some control of existing sources of VOCs in ozone nonattainment areas, they do not extend to sources in attainment areas, and also do not necessarily reach every important source in each industry source category.[470] Section 111(d), by contrast, can reach existing sources of

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[467] *See, e.g.*, 42 U.S.C. § 7511.
[468] 42 U.S.C. § 7602(g).
[469] 73 Fed. Reg. 28,322, 28,326 (May 16, 2008) (final rule on using the PM 2.5 standards in the NSR program), attached hereto as Exhibit 153; 72 Fed. Reg. 20,586, 20,590-91 (Apr. 25, 2007) (Clean Air Fine Particle Implementation Rule, making the same points), attached hereto as Exhibit 154.
[470] *See* 42 U.S.C. § 7511a.

VOC pollution in attainment and in nonattainment areas, and can provide a uniform, clear regulatory standard for actors across the oil and gas industry, which is a major source of VOC pollution.

These distinct statutory purposes and distinct air pollution problems support treatment of VOCs as 111(d) pollutants, even were the plain language of the statute and regulations not so clear. Indeed, it would be unreasonable for EPA *not* to use its discretion to regulate VOCs under section 111(d).[471]

C. EPA Has Used Its 111(d) Authority to Functionally Regulate VOCs and Methane Before

Although EPA has not previously issued section 111(d) standards that explicitly control VOCs, its standards of performance for municipal solid waste landfills are, functionally, 111(d) VOC standards, and provide a useful model here.

Landfills are significant sources of methane, VOCs, and other pollutants. To address existing landfills, EPA promulgated 111(d) control guidelines concurrently with its new source performance standards. These guidelines are based upon a pollutant mixture of "non-methane organic compounds" (NMOC).[472] NMOC is 80% VOC by mass, so NMOC controls are fundamentally VOC controls, which happen to also control some non-VOC pollutants.[473,474] Likewise, though EPA, as a legal matter, excluded methane from regulation as part of "NMOC", methane is co-emitted with NMOC, meaning that NMOC controls reduce methane emissions as well as non-methane organic compounds.[475]

EPA emphasized the benefits of VOC and methane control (along with control of hazardous air pollutants co-emitted with NMOC at existing sources) in its rulemaking. As it explained:

> NMOC includes [VOC], hazardous air pollutants (HAPs), and odorous compounds. VOC emissions contribute to ozone formation which can result in adverse effects

[471] It is true that EPA has once declined to use its 111(d) authority to regulate VOCs in its 2007 NSPS for VOC leaks from synthetic chemical manufacture and refineries (subpts. VV, VVa, GGG, and GGGa), 72 Fed. Reg. 64,680, 64,868 (Nov. 16, 2007), attached hereto as Exhibit 155. It did so without detailed explanation or analysis, however, and is free to change that position by rulemaking here, particularly in view of the industry's extraordinarily high VOC emissions.

[472] 61 Fed. Reg. 9,905, 9,905 (Mar. 12, 1996) (final 111(d) standards); 40 C.F.R. §§ 60.751 & 60.754 (regulatory NMOC definition), attached hereto as Exhibit 156.

[473] *See* 61 Fed. Reg. at 9,912 (stating that NMOC emissions of 50 tpy "correspond[] to a VOC emission rate of 40 tpy.").

[474] See also EPA, Municipal Solid Waste Landfill New Source Performance Standards (NSPS) and Emissions Guidelines (EG)—Questions and Answers (1998) at 19 (explaining that "NMOC is non-methane organic compounds, which include volatile organic compounds (VOC) as well as other organic compounds"), available at http://www.epa.gov/ttnatw01/landfill/landfq%26a.pdf, attached hereto as Exhibit 157.

[475] Of course, as discussed above, we do not agree with EPA's failure to regulate methane here.

> to human health and vegetation. Ozone can penetrate into different regions of the respiratory tract and be absorbed through the respiratory system. The health effects of exposure to HAPs can include cancer, respiratory irritation, and damage to the nervous system. Methane emissions contribute to global climate change and can result in fires or explosions when they accumulate in structure on or off the landfill site . . . . Today's rules will serve to significantly reduce these potential problems with [landfill gas] emissions.[476]

EPA further specified the benefits of reducing existing source emissions of VOCs and methane in its proposed rule, listing five benefits: (1) reduced ozone formation; (2) incidental control of HAPs; (3) managing the "well-documented danger of fires and explosions"; (4) controlling unpleasant odors; and (5) reducing the severity of global climate change.[477]

To address these harms, EPA issued 111(d) standards embracing all large existing landfills,[478] requiring them to install emissions control systems that collect and destroy escaping landfill gas.[479] These standards, which covered hundreds of existing landfills,[480] halved NMOC emissions from those sources, and reduced methane emissions by about 40%.[481]

EPA can and must take several lessons from this experience:

First, as discussed above, EPA has authority to set and direct section 111(d) standards for VOCs although VOCs are precursors of the 108 pollutant ozone. VOCs are an important precursor to ozone, a listed 108 pollutant. Without 111(d) regulation, not all important existing sources of these precursor pollutants will be subject to emissions controls. For instance, although section 182 of the Act requires state implementation plans to include some control of existing sources in ozone nonattainment areas, it does not extend to sources in attainment areas, and also does not necessarily reach every important source in each industry source category.[482] Section 111(d) is thus an important adjunct to controlling these existing sources. In the landfill standard, EPA took this view. Although EPA opted to regulate VOCs as part of NMOC, this distinction is not practically important, whatever its legal significance: NMOC controls regulate VOCs, and

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[476] 61 Fed. Reg. at 9,905-06. *See also* 56 Fed. Reg. 24,468 (May 30, 1991) (proposed rule), attached hereto as Exhibit 158.
[477] *Id.* at 24,472-75.
[478] We do not take a position here as to the appropriateness of EPA's emissions threshold decisions for landfills.
[479] 61 Fed. Reg. at 9,907-9,908.
[480] *Id.* at 9,914.
[481] *Id.* at 9,908-9.
[482] *See* 42 U.S.C. § 7511a.

the regulation is founded on these benefits.[483] EPA could just as readily have regulated VOCs alone.

Second, section 111(d) controls may incidentally control hazardous air pollutants, or criteria pollutants. Although section 111(d) may not be relied on to *satisfy* section 112 requirements due to the differing statutory requirements between the two programs, regulations targeted at non-HAPs may produce important HAP co-benefits, but the existence of those co-benefits does not eliminate the requirement to directly regulate the pollutant in question. Thus, though landfill gas contains several HAPs,[484] and regulating NMOC would help reduce their emissions, EPA did not view this benefit as an impediment to section 111(d) regulation. Instead, it emphasized HAP control as an important additional benefit to section 111(d) control.[485]

Third, section 111(d) regulations for existing sources can be designed to rapidly produce significant emissions reductions. The landfill standards were designed to reduce NMOC emissions by 7 million megagrams in the first four years of their operation.[486]

Oil and gas production sources offer similar opportunities. Once again, EPA has the opportunity of regulating a class of existing sources whose emissions are cumulatively large. Existing source controls would produce all five of the benefits EPA identified for its earlier landfill section 111(d) rules, as controlling VOCs would reduce VOC and methane emissions, along with some HAP emissions.[487] And, once again, existing sources can readily adopt cost-effective controls (and, in fact, already do so as set forth elsewhere in these comments). We outline some of these potential controls below.

D. Design Approaches for a Section 111(d) Standard for VOC and Methane

Like standards of performance for new sources, emission guidelines must reflect "Best Demonstrated Technology."[488] New source standards are the starting point for existing source standards, but those rules may be modified to "take into account the remaining useful life of the existing sources to which such standard applies."[489]

Many of the standards EPA has proposed for new sources can be readily and cost-effectively applied to existing sources without losing rigor, as demonstrated by the standards in place in Wyoming and Colorado for storage vessels, gas processing plants

[483] 61 Fed. Reg. at 9,906.
[484] 56 Fed. Reg. at 24,474
[485] *Id.*
[486] *Id.* at 9,908.
[487] *See* RIA at 4-18 – 4-35.
[488] 40 C.F.R. § 60.22(b)(5).
[489] 42 U.S.C. § 7411(d)(1); *see also* 40 C.F.R. § 60.24(c) (providing that 111(d) standards generally "shall be no less stringent than the corresponding emission" standards for new sources).

and pneumatic devices, described above.[490] Similar approaches could be used to control methane and VOCs for each facility type, so we sketch these design principles for both pollutants, recognizing that separate regulations must be promulgated for each pollutant in order to fully regulate these sources. We discuss each facility type in turn.

Notably, although the same general *technology* can control methane and VOCs, allowing us to describe these standards jointly, these technologies will not necessarily be *applied* across the sector – and nor can their use be enforced -- unless EPA issues section 111(d) standards for both VOCs and methane. This gap occurs, as we have explained above, because VOCs and methane are not co-emitted in equal proportions across the sector. Instead, the proportion of methane to VOC emissions grows steadily as gas moves from the wellhead to the distribution sector, meaning that VOC standards are unlikely to operate rigorously further down the production chain, and that, as a result, methane-specific controls are needed to fully achieve the existing source benefits we describe below.

1. Standards for Existing Pneumatic Devices

Pneumatic devices in the production sector are responsible for 17% of production sector emissions emitting 67 Bcf of methane annually. Pneumatics in the transmission sector emit another 12 Bcf.[491] Because methane is co-emitted with VOCs, these controllers are also significant VOC sources. According to EPA, a single year's worth of new bleed devices (about 17,000 controllers) will emit 32,739 tons per year of VOCs, along with 117,766 tons of methane.[492] New controllers, however, are only a small fraction of the existing population of controllers. The latest EPA GHG Inventory estimates that 564,842 pneumatic controllers exist in the production, processing, transmission and storage sectors as of 2009.[493] Using EPA's estimates of the percentage of existing controllers that are high versus low or no-bleed, approximately 243,976 and 27,481 high-bleed controllers existed in 2009 in the production and transmission/storage sectors respectively.[494] This existing population emits 556,373 tons of VOCs annually. Applying EPA's assumption that 80% of high-bleed devices can be replaced with low or no-bleed devices, a 111(d) standard that requires replacement of high-bleed controllers would

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[490] Elsewhere in these comments, we discuss ways that the new source standards should be improved. We expect that corresponding improvements would also appear in the proposed existing source standards.

[491] Copeland & Williams Report at 32-33.

[492] EPA, TSD at 5-10.

[493] EPA, *Inventory of U.S. Greenhouse Gases and Sinks (1990-2009), April 2011*, Table A-120, p. A-149, http://epa.gov/climatechange/emissions/usinventoryreport.html. This is a more recent estimate than that provided in the TSD which estimates the pneumatic controller population for 2004 to be 498,000. TSD, 5-1. We refer here to the estimate of existing source population contained in the Inventory because it is more recent and also because it breaks out the number of controllers per industry segment (i.e.: production, processing and transmission).

[494] EPA estimates the number of bleed devices in the production and transmission sectors to be 51% and 32%, respectively. TSD at 5-7

thenceforth annually remove approximately 1,288,195 tons of methane and 351,326 tons of VOCs from the atmosphere from the production sector and 6,508 tons of methane and 1,759 tons of VOCs from the transmission/storage sector.[495] Since these figures represent the existing population as of 2009, the actual pollution reductions are likely much greater since oil and gas production has increased since 2009. EPA could, therefore, achieve significant benefits by applying controls to existing pneumatics.

The proposed new source controls provide a useful model. As proposed, the rules define each affected facility as a "single pneumatic controller."[496] As a result, each new controller must meet the performance standards, which generally require no-bleed valves at processing plants, and low-bleed controllers elsewhere.[497] As a result, replaced controllers must be no or low-bleed.[498] Given enough time, as old controllers wear out, this requirement will therefore gradually cause the entire population of controllers to turn over.

But without 111(d) standards, replacing the existing collection of controllers will take a great deal of time. EPA estimates pneumatic controllers have a ten-year expected lifetime for amortization purposes, but controllers may last even longer in practice – and EPA has developed no data showing otherwise.[499] Existing source standards could usefully accelerate replacement of polluting controllers.

Therefore EPA must set emissions standards which drive operators to timely replace their existing controllers with no-bleed controllers or (if no-bleed controllers cannot be used), low-bleed controllers in a timely fashion. These replacements are highly likely to be cost-effective. EPA determined that, thanks to increased natural gas capture from replacement devices, its new source controller standards will generate annualized net savings of $1,159 per controller in the production sector, and costs of only $23 per controller in the transmission and storage sector.[500] Because these estimates *already* include the costs of replacing controllers at existing sources where sources voluntarily undertake replacement, EPA can be sure that such replacements are both feasible and cost-effective.

Notably, Colorado and Wyoming have reached similar conclusions regarding the efficacy and cost-effectiveness of replacing high-bleed devices with low or no-bleed ones. Colorado requires that, "when new, replaced, or repaired pneumatic devices are

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[495] TSD at 5-12 (assuming 80% of high-bleed controllers can be retrofit as low or no-bleed)
[496] Proposed 40 C.F.R. § 60.5365.
[497] Proposed 40 C.F.R. § 60.5390.
[498] *See id.*
[499] TSD at 5-16.
[500] RIA at 3-15. Note that the net positive cost in transmission and storage, in contrast to the negative cost in the production segment, arises because pipeline firms typically do not own the gas conserved with no-bleed or low-bleed controllers (since they do not own the gas in their pipelines). We believe that the industry as a whole, therefore, will save money from installation of less wasteful controllers.

installed, low or no bleed valves must be used, where technically feasible,"[501] and Wyoming requires all new and modified controllers to be low or no-bleed.[502] Moreover, in certain ozone non-attainment areas, Colorado also requires all high-bleed pneumatic controllers to "be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic compressor". Colorado required such replacements within months of the time the regulation was promulgated.[503] Colorado determined that such retrofits were highly cost-effective, resulting in savings of $747 per controller including gas savings.[504]

To be sure: although replacement costs are either negative or very small, there may well be nontrivial labor and logistics costs associated with replacing the entire population of existing controllers on an accelerated schedule. EPA could reflect that logistical challenge by designing the existing source standard around the "remaining useful life" of these devices, staggering or extending a replacement requirement to reflect instrument failure rates and repair frequencies. For instance, an existing source standard might require that all existing controllers be replaced within three years or some other reasonable period, allowing for a manageable compliance period. Alternately, EPA might further calibrate a replacement time period by comparing replacement costs with the cost savings resulting from a new no-bleed or low-bleed controller, and then setting the replacement period at the point at which, on average, savings from a new controller balance out the labor costs of an early replacement. Finally, EPA might simply seek to take advantage of repair visits to existing facilities, and specify that, when a facility is visited for planned maintenance; existing controllers are to be replaced at the same time as other work is to be done.

Whichever of these options EPA ultimately proposes and evaluates, the core concern is the same: The existing fleet of controllers is a significant methane and VOC source. If EPA accelerates the replacement frequency for these devices, the public will capture major emissions benefits –controlling just new devices would reduce VOCs by 90,685 tpy and achieve equally significant methane benefits. Swiftly replacing existing devices will yield far greater reductions.

2. Standards for Existing Compressors

EPA estimates suggest that there are over 12,000 existing reciprocating compressors[505] and 1,400 existing centrifugal compressors.[506] Leaks from these compressors make

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[501] Co. Oil and Gas Conserv. Commission Rule 805(b)(2)(E), attached hereto as Exhibit 159.
[502] Wy. Dept. of Envt'l Quality, *Oil and Gas Production Facilities* (Mar. 2010) at 10, attached hereto as Exhibit 160.
[503] Co. Department of Public Health and Environment Regulation 7, XVIII.C.2 (promulgated Dec. 12, 2008. High-bleed controllers had until May 1, 2009 to comply), attached hereto as Exhibit 161.
[504] Revised final Economic Impact Analysis for Proposed Alternative #2 for Proposed State-only Revisions to the Air Quality Control Commission's Reg. Number 7 (Dec. 11, 2008), attached hereto as Exhibit 162.
[505] TSD, 6-8, 9.

them dominant emissions sources,[507] emitting on the order of 105 Bcf of methane across the production, processing, and transmission and storage sectors.[508] Compressor VOC emissions are, unsurprisingly, also substantial. EPA states that just the *newly installed* compressors (not including compressors installed to replace existing compressors) now covered by the proposed standards would emit 2,798 tons of VOCs annually in the absence of the proposed standard.[509] Emissions from existing reciprocating compressors in the processing and transmission sectors alone equal approximately 37,000 Tpy.[510] EPA has low-cost options to extend controls to these existing sources. Emission guidelines that require replacement of rod-packing from existing compressors in the processing sector would remove approximately 25,258 tons of VOCs and 90,694 tons of methane. Similar reductions can be achieved from compressors in the transmission and storage sector, namely 5,010 tons of VOCs and 181289 tons of methane. These reductions, which total 30,268 tons of VOC and 271,983 tons of methane, do not include reductions from the 34,930 compressors located at wellheads, gathering and boosting stations. Emissions reductions from these sources are not estimated since EPA's GHG Inventory does not disaggregate wellhead compressors from those located at gathering and boosting stations yet EPA applies different emission reductions to each type of compressor.[511]

Beginning with reciprocating compressors, which are by far the more common compressor type, EPA can directly extend its new source performance standard. That standard would require operators to replace reciprocating compressor rod-packing "before the compressor has operated for 26,000 hours."[512] This simple maintenance standard, applied at new sources, saves 1,759 tons per year of VOCs,[513] and does so at a low cost. EPA estimates cost per ton of VOC controlled (with saved natural gas offsets) at a few thousand dollars or less (including savings in some cases) for gathering, processing, transmission, and storage compressors.[514] Nothing prevents operators from immediately applying an identical maintenance approach to existing compressors, and EPA must so require.

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[506] EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011) at Table A-120., p. A-122. EPA does not provide an estimate of the number of existing centrifugal compressors in the TSD.

[507] This emissions source is both under-controlled and under-measured: In 2010, for instance, EPA uprevised its emissions factor for leaks from centrifugal compressor from 0 to 233 metric tons CH_4/year. TSD at 9.

[508] *See* EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011) at Table A-120., p. A-122.

[509] TSD, Table 6-5.

[510] These calculations are based on EPA's baseline VOC emissions for reciprocating compressors in Table 6-3 of the TSD. Note because EPA does not provide estimates of the number of reciprocating compressors at wellheads or in the storage sector, and this information is also not provided in EPA's GHG inventory, we do not here estimate emissions from compressors in these sectors.

[511] See TSD 6-6, noting that the GHG Inventory does not separate wellhead from gathering and boosting compressors and Table 6-6 applying emission reductions to different types of compressors.

[512] Proposed 40 C.F.R. §60.5385.

[513] TSD, Table 6-6.

[514] TSD, Table 6-7.

Centrifugal compressors also offer significant control opportunities. Requiring dry seals for non-wellhead compressors alone, as EPA now proposes for new sources, would reduce VOC emissions by 329 tons per year (this number is low because EPA assumes few new installations of centrifugal compressors each year, and replacements of existing compressors are not included in this figure).[515] Using the estimate of existing centrifugal compressors in the 2009 GHG Inventory, replacement of wet seals with dry on compressors would remove 13, 926 tons per year of VOCs (11,628 from the processing sector and 2298 from the transmission/storage sectors).[516] The resulting savings are substantial: For each ton of VOC avoided, operators recover over $25,405 in avoided natural gas loss and O&M costs annually at transmission and storage compressors, and another $6,892 at processing compressors.[517] The result is millions of dollars in avoided costs each year.[518]

If EPA's emissions standards drove operators to replace wet seals with dry seals at existing compressors, operators would capture far more benefits, as existing centrifugal compressors greatly outnumber new compressors. We therefore recommend that EPA set these standards to drive such replacements in existing compressors.

3. Standards for Existing Storage Vessels

Under the proposed NESHAP, EPA has already proposed a 95% emissions control requirement for new and existing storage vessels at major sources of HAPs.[519] For new storage vessels not covered by the NESHAP, EPA has proposed an NSPS requirement that would apply an identical standard at wellsite storage vessels which have the potential to emit 6 or more tons per year of VOCs, at a cost of $143 per ton of VOCs captured for large vessels.[520,521,522] Combined, these standards cover many tanks, but likely leave a population of existing vessels which are not major HAP sources.

These remaining existing tanks must be subject to the same degree of emissions control as is required for all other tanks. EPA estimates the existing population of condensate tanks in 2008 to be 57, 8447.[523] Such a standard would be cost-effective, especially if phased in over a reasonable time period. Colorado, for instance, developed cost data for retrofits of condensate tanks, concluding that condensate tanks could be retrofitted for

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[515] TSD, Table 6-8.
[516] EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011), Table A-120., p. A-122.
[517] TSD, Table 6-22.
[518] RIA, Table 3-3.
[519] 76 Fed. Reg. at 52,813. (Proposed 40 C.F.R. §63.766).
[520] *Id.*
[521] 76 Fed. Reg. at 52,800. (Proposed 40 C.F.R. § 60.5395).
[522] EPA has proposed to exempt some small throughput vessels from this standard.
[523] TSD 7-4. Note the most recent GHG Inventory does not provide an estimate of the population of tanks used in the natural gas sector so this analysis relied on the information contained in the TSD rather than EPA's most recent GHG Inventory.

roughly $6,921 per tank.[524] Using the average VOC emissions for condensate and oil tanks presented in Table 7-12 of the TSD (103 Tpy) in 2008 the existing tanks population was responsible for the emission of 59,580,041 Tpy of VOCs into the atmosphere. If the NSPS 95% control requirement were extended to these sources, it would result in the removal of 56,601, 039 Tpy VOCs, and would also achieve substantial methane reductions.

In view of the potential for cost-effective emissions savings, Colorado requires existing tanks emitting more than one ton per year of VOCs within certain ozone nonattainment area to retrofit to meet a 95% emissions control requirement[525] within the first 90 days of producing a newly drilled, re-completed, re-fractured or otherwise stimulated well.[526] After that, controls may be removed provided the owner or operator can demonstrate that all of the tanks within his or her control meet system-wide emission limits.[527] EPA must apply the same approach nationally. Whatever control efficiency requirement it ultimately applies to new tanks must be extended to existing vessels which are not already covered by the NESHAP, and must be applied on a reasonably strict retrofit schedule.

4. Standards for Existing Wells

Well completions of hydraulically fractured wells[528] and liquids unloading from conventional wells[529] are two of the largest sources of methane and VOCs from the oil and natural gas industries. EPA proposes to define well completions and recompletions as modifications, which would trigger the performance standards. Proposed 40 C.F.R. § 60.5365. Unfortunately, EPA fails to regulate liquids unloading altogether. Above, we call for this failing to be rectified. As we note above, liquids unloading is a physical alteration of the well which increases emissions and thus should be considered a modification which would trigger performance standards.

If the proposed rule stands, and EPA also regulates liquids unloading and considers it to be a modification, EPA will be able to control the major sources of methane emissions from existing conventional and hydraulically fractured gas wells (even without a 111(d) standard). If, however, EPA alters the proposal concerning hydraulically fractured wells

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[524] Colorado Air Quality Control Commission, *Revised Final Economic Impact Analysis for Proposed Alternative #2 for Proposed State-Only Revisions to the Air Quality Control Commission's Reg. Number 7* (Dec. 11, 2008), attached hereto as Exhibit 162.

[525] CO. Department of Public Health and Environment Regulation 7 at XII.D & XVII.C; *see also* Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(A) & (B) (requiring such retrofits in certain counties, and within ¼ mile of schools, hospitals, and similar facilities).

[526] CO. Department of Public Health and Environment Regulation 7 at XII.D; *see also* Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(A) & (B) (requiring such retrofits in certain counties, and within ¼ mile of schools, hospitals, and similar facilities, for tanks that emit 5 Tpy of VOCs or more).

[527] CO. Department of Public Health and Environment Regulation 7 at XII.D.

[528] 76 Fed. Reg. at 52,756.

[529] US Greenhouse Gas Inventory, Table A-120 at A-149 – A-153.

or fails to consider liquids unloading as a modification in the final rule, it should issue 111(d) standards to fill any gaps.

Of course, the existing well standards should also reflect the greater coverage we recommend for new sources, *supra*. Most significantly, 111(d) standards should regulate oil wells, in addition to gas wells.

5. Standards for Leak Detection and Repair

EPA proposes to require all new gas processing plants to comply with the enhanced leak detection standards of subpart VVa, while existing plants will continue to be bound by the more relaxed standards of subpart VV.[530] This is not an effective approach. As EPA explains, subpart VVa not only captures more VOCs (and methane), it is also less expensive per ton of pollutant because "[a]lthough the cost of repairing more leaks is higher, the increased VOC control afforded by subpart VVa level controls more than offsets the increased costs" thanks to captured natural gas sales.[531]

EPA estimates there are 577 existing plants operating in the U.S. today.[532] Applying the annual emission reductions from implementing a Subpart VVa LDAR program to individual gas plants estimated in Table 8-13 of the TSD, extending the Subpart VVa requirements to existing sources would result in an additional reduction of 7,790 tons of VOCs from the atmosphere.

EPA must apply this more effective, and less expensive, standard to existing processing plants immediately. No technical or logistical efforts appear to require a long phase-in period, though some need to hire or train sufficient workers may delay phase-in somewhat. Even assuming some phase-in period, though operators and the public can benefit from enhanced leak control as soon as EPA extends these standards to existing sources.

6. State Models

As we have described above, standards in Colorado and Wyoming demonstrate that standards of performance to control air pollution from existing sources are both "achievable" and "adequately demonstrated".[533] To underline this point, we gather those requirements here. Table 3 table illustrates the scope of existing sources covered by Wyoming and Colorado's rules.

Table 3

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[530] *See* 76 Fed. Reg. at 52,764.
[531] *Id.* at 52,765.
[532] TSD, 8-16.
[533] See 42 U.S.C. § 7411(1)(1) (defining "standard of performance"); 42 U.S.C. § 7411(d)(1).

Existing Source	Proposed NSPS	Wyoming	Colorado
Condensate tanks	95% control of tanks with emissions ≥ 6 Tpy VOCs.	CDAs and JPAD[534]: New and modified facilities must control VOC flash emissions by 98% upon first date of production (FDOP). May remove controls after one year if VOC emissions < 8 tpy. Statewide: New and modified facilities must control VOC flash emissions ≥10 tpy by 98% upon FDOP. May remove controls after one year if emissions < 8 tpy.	Tanks with VOC emissions greater than 2 Tpy, under common ownership and control, and with cumulative emissions = or > 30 Tpy VOCs located in ozone NA or Attainment/Maintenance area, must meet system-wide declining caps that require 90% control during ozone season and 70% control remainder of year.[535] Individual tanks located at gas processing plants in ozone NA or Attainment/Maintenance area, with emissions > 2 Tpy VOCs must achieve 95% control on rolling 12-month basis.[536] Tanks with PTE 5 Tpy or more located near public places in the Piceance basin must achieve 95% VOC control.[537]
Crude oil tanks	95% control of tanks with VOC emissions ≥ 6 Tpy.	Same as condensate tanks.	Tanks with PTE 5 Tpy or more located near public places in the Piceance basin must achieve 95% VOC control.[538]
Produced water tanks	N/A	Same as condensate	Tanks with PTE 5 Tpy or more located near public places in the

[534] *Id*. CDA refers to "Concentrated Areas of Development". JPAD refers to the Jonah and Pinedale Anticline Development Area.
[535] Colorado Reg. 7, XII.D.2.(a)(x).
[536] Reg. 7, XII.G.2.
[537] Colorado Oil and Gas Conservatin Commission Rule ("COGCC") 805(b)(2)(A),(B).
[538] Colorado Oil and Gas Conservatin Commission Rule 805(b)(2)(A),(B).

		tanks.	Piceance basin must achieve 95% VOC control.[539]
Pneumatic devices	Low bleed devices in production and transmission sectors. No-bleed devices at gas plants.	Operators must use low or no-bleed devices or route discharge streams to closed loop systems.	New and existing gas-activated controllers at or upstream of gas processing plants in ozone nonattainment (NA) and Attainment/Maintenance areas (NA/M) must be low-bleed.[540] Statewide, new, replaced or repaired devices in production sector must be low or no-bleed, where technically feasible.[541]
Gas processing plants	N/A	N/A	Plants in ozone nonattainment areas or Attainment/Maintenance areas must comply with the same federal leak detection and repair standards that apply to new sources in subpart KKK.[542]
Wells	Reduced emission completions for re-completed and re-fractured hydraulically fractured gas wells.	Green completions.	Green completions.

Wyoming and Colorado's standards to control air pollution from existing storage vessels, pneumatic devices, and wells are based upon or reflect the same practices or standards that EPA has determined in this rule represent Best Demonstrated Technology, or Best System of Emission Reduction, for new sources. This fact demonstrates that these practices and standards are achievable and adequately demonstrated for existing sources as well. EPA thus must look to the Wyoming and Colorado standards when designing emission guidelines for existing sources as required by the Act.

7. Conclusion

[539] Colorado Oil and Gas Conservatin Commission Rule 805(b)(2)(A),(B).
[540] Reg. 7, XVII.
[541] COGCC Rule 805(b)(2)(E).
[542] Reg. 7, XII.G.3.

Section 111(d) and its implementing regulations require EPA to control VOCs and methane at existing sources as well as at new sources. As we have demonstrated, these existing source standards can readily be extrapolated from EPA's work on the new source performance standards, can be applied quickly, and are likely to be highly cost-effective, especially if phased in properly. As with the earlier landfill standards, oil and gas 111(d) standards will have significant public health and welfare benefits, reducing ozone formation, HAPs, and the sector's contribution to climate change. EPA must therefore include a proposal for such standards in or concurrent with its final rulemaking for the 111(b) standards, or include a schedule in the 111(b) rulemaking committing to a proposal in the near future.

VI. COMPLIANCE AND ENFORCEMENT ISSUES

EPA's proposed standards cover thousands of facilities spread across a wide range of terrains and jurisdictions. To properly enforce them, EPA and the states will need substantial resources and clear authority. In our sector-specific comments, we have made several suggestions for clarifying the rule to enhance its enforceability. In this section of the comments we consider enforcement issues more generally, focusing on the implications of EPA's proposal to exempt certain sources from permit requirements under Title V of the Clean Air Act and upon EPA's proposal to develop an affirmative defense for noncompliance. We trust these suggestions will help make the final rule enforceable as a practical matter, and thus ensure its full rigor, as well as overall transparency and widespread compliance.[543]

A. Title V Exemption

[543] With regard to transparency, it is important to note – and EPA must clarify -- that all information reported pursuant to proposed 40 C.F.R. §§ 60.5410, 60.5415, and 60.5420 must be disclosed to the public. Section 114 of the Clean Air Act authorizes EPA to collect information and mandates that this information be available to the public. EPA regulations provide that all data collected by EPA under any CAA provision will be presumed to have been collected under § 114, regardless of whether the authority providing for the collection cites § 114, and that this information will "shall" be public. 40 C.F.R. §§ 2.301(b)(2), (f). The only exception is that EPA may determine that certain information other than "emission data" is confidential business information that need not be disclosed. 42 U.S.C. § 7414(c). The exemption does not apply here, because all of the information reported pursuant to the proposed NSPS rules is "emission data." "Emission data means . . . [i]nformation necessary to determine the identity, amount, frequency, concentration, or other characteristics" of emissions actually emitted by a source or that the source was authorized to emit. 40 C.F.R. § 2.301(a)(2)(i)(A)-(B). This information includes "a description of the manner or rate of operation of the source" and a "general description of the location and/or nature of the source." *Id.* § 2.301(a)(2)(i)(B)-(C). The information required pursuant to the proposed NSPS falls solidly within this category. Although EPA has set technology or work practice standards for many sources, these standards serve as a surrogate for actual emissions. Even if this information was not emission data, nothing indicates that it would be confidential business information that EPA could shield from disclosure.

EPA proposes to exempt well completions, pneumatic devices, compressors and small storage tanks from the obligation to obtain Title V permits.[544] As a matter of law, promulgation of an NSPS regulating these entities would bring them within the ambit of Title V.[545] When promulgating an NSPS, however, EPA may exempt non-major sources from Title V obligations in the limited circumstances where compliance would be "impracticable, infeasible, or unnecessarily burdensome" for the source.[546] Here, EPA argues that Title V is an "unnecessary[] burden[]."[547] We strongly object to the proposed Title V exemption.

"Title V of the 1990 Amendments to the Clean Air Act (CAA) requires that certain air pollution sources, including every major stationary source of air pollution, each obtain a single, comprehensive operating permit to assure compliance with all emission limitations and other substantive CAA requirements that apply to the source."[548] Regulations implementing Title V are codified at 40 C.F.R. parts 70 and 71. A Title V permit must, *inter alia*, list all emissions limitations and standards applicable to the source;[549] ensure that monitoring and recordkeeping are sufficient to demonstrate compliance;[550] and require payment of fees.[551]

Rather than treating the statutory exemption as a narrow limitation on a rule of general applicability adopted by Congress, EPA seems to assume that the exemption is available as a matter of right, unless some added benefit can be demonstrated. Accordingly, instead of simply examining whether Title V permitting is "unnecessarily burdensome," EPA interprets the exemption as permitting it to balance the enforcement and environmental benefits of Title V against the costs to the facility operator.[552] Moreover, the proposed rule understates the benefits of Title V by completely ignoring the role Title V fees play in funding state enforcement programs. The proposal conversely assumes that costs to operators are unbearable without considering the ways in which these costs may (and are likely to) be reduced or providing any specific data regarding the magnitude of these costs and the operators' ability to bear them. Accordingly, the proposed title V exemption is insufficiently supported and, in any event, unwarranted.

1. EPA's Multifactor "Unnecessarily Burdensome" Test

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[544] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5370(c)).
[545] 42 U.S.C. § 7661a(a), 40 C.F.R. § 70.3(a)(2).
[546] 42 U.S.C. 7661a(a), 40 C.F.R. § 70.3(b)(2).
[547] 76 Fed. Reg. at 52,751.
[548] *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 993-94 (D.C. Cir. 2005) (citing 42 U.S.C. §§ 7661a(a), 7661c(a)), attached hereto as Exhibit 163
[549] 40 C.F.R. § 70.6(a)(1)
[550] 40 C.F.R. § 70.6(a)(3);
[551] 40 C.F.R. §§ 70.6(7), 70.9.
[552] *Id.*

Following a trend established in several recent rulemakings, EPA's proposal discusses five factors in evaluating whether Title V imposes an unnecessary burden.[553,554] Specifically, EPA articulates a four-factor test, but then adds an additional consideration. The four factors are:

(1) Whether Title V would result in significant improvements to the [applicable substantive] compliance requirements . . .

(2) Whether Title V permitting would impose a significant burden on these non-major sources and whether that burden may be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies;

(3) Whether the costs of Title V permitting for these non-major sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources;

(4) Whether there are implementation and enforcement programs in place that are sufficient to assure compliance . . . without relying on Title V permits.[555]

After discussing these factors, EPA separately considers "whether exempting . . . [these] sources would adversely affect public health, welfare or the environment."[556]

As a threshold matter, we note the cumbersome nature of this test. The distinction, if any, between the first and fourth factors is unclear. Similarly, evaluation of effects on "public health, welfare or the environment" largely subsumes the question of whether Title V would improve compliance with substantive standards, because EPA must presume that those standards further these broader goals. Lastly, insofar as the fourth and fifth factors have independent relevance, EPA must discuss these factors before the third "factor," which itself appears to be merely a weighing of factor two against the other concerns. Moreover, EPA's application of its factors in this instance would seem to allow it to exempt all sources. EPA has not explained how the costs and benefits of Title V permitting in this instance are significantly different from the burden imposed on other sources that are subject to Title V obligations. Moreover, EPA's application of its factors in this instance would seem to allow it to exempt all sources. EPA has not

[553] 76 Fed. Reg. at 52,751 (citing *Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75323 (Dec. 19, 2005)).
[554] EPA cites this document as the "Title V Exemption Rule." *See* 76 Fed. Reg. at 52751. Rather than announce a general rule regarding Title V exemptions, the cited rule was a case-specific determination as to whether five nonmajor source categories subject to NESHAP should be exempted from Title V. 70 Fed. Reg. at 75,320, 76,323, attached hereto as Exhibit 164. In the proposal and final rule for the five-category exemption, EPA used a test similar to the one EPA uses here. *Id.*, *see also Proposal To Exempt Area Sources Subject to NESHAP From Federal and State Operating Permit Programs*, 70 Fed. Reg. 15,250, 15,253 (March 25, 2005), attached hereto as Exhibit 174.
[555] *Id.*
[556] *Id.*

explained how the costs and benefits of Title V permitting in this instance are significantly different from the burden imposed on other sources that are subject to Title V obligations.

2. Title V Permit Fees Will Further Environmental Protection and Compliance with the NSPS

Assuming *arguendo* that EPA's test lays out a reasonable set of distinguishable factors, in discussing the three "benefit" factors of the above balancing test here, EPA failed to consider the important role Title V fees play in the CAA's regulatory regime.

In evaluating the first factor, EPA explained that "[o]ne way that Title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with permit terms and conditions reflecting the emission limitations and control technology requirements imposed in the standard."[557] EPA concluded the proposed NSPS's reporting, monitoring and recordkeeping requirements were, *e.g.*, "sufficient to assure compliance with the proposed [NSPS] requirements," such that the monitoring, reporting and recordkeeping required by Title V would provide little additional benefit.[558] We note that Title V requires "prompt reporting of deviations from permit requirements" and reporting on a semiannual, rather than annual, basis,[559] whereas the proposed NSPS only requires reporting on an annual basis, together with notification of well completions.[560] Timelier reporting would facilitate enforcement.

More importantly, reporting is not the only mechanism by which Title V improves compliance. Title V also improves compliance by requiring operators to pay fees that, in turn, fund state enforcement programs. Title V requires that permit programs impose and collect annual fees "sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program requirements of [Title V], including the reasonable costs of . . . implementing and enforcing the terms and conditions of any . . . permit (not including any court costs or other costs associated with any enforcement action)."[561] As EPA has interpreted this language, Title V permit fees may be used for all enforcement costs for Title V sources incurred prior to the filing of an administrative or judicial compliant.[562]

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[557] 76 Fed. Reg. at 52,752.
[558] *Id.*
[559] 40 C.F.R. § 70.6(a)(3)(iii)(B)
[560] 76 Fed. Reg. at 52,805-08 (Proposed 40 C.F.R. §§ 60.5410, 60.5415, 60.5420).
[561] 42 U.S.C. § 7661(b)(3)(A)(ii).
[562] *Reissuance of Guidance on Agency Review of State Fee Schedules for Operating Permits Programs Under Title V*, at pages 3 and 16 of 25 (Aug. 4, 1993), available at http://www.epa.gov/ttn/oarpg/t5/memoranda/fees893.pdf, attached hereto as Exhibit 166.

These fees are essential, because state budgets have slashed delegated CAA programs to the point where almost all available resources are derived either from CAA grants or Title V fees. For example, Oregon's Department of Environmental Quality states that

> Because other funding sources have become less available over time, fees pay for 90 to 95 percent of the Air Contaminant Discharge Permit Program. To address budget shortfalls, the Oregon Legislature has cut general fund support for the Air Contaminant Discharge Permit Program and shifted more of the funding to fees. Federal funds for state air quality programs have been flat for many years, and prospects for significant increases in federal funds are slim given federal budget challenges.[563]

Because Title V permit fees cannot be used for purposes other than enforcement and implementation of the Title V program, Title V fees directly and necessarily increase enforcement capacity.

EPA itself implicitly concedes that states lack the resources to enforce the proposed NSPS obligations. In discussing the status of implementation and enforcement programs (the fourth "unnecessarily burdensome" factor), EPA states that

> Before EPA will delegate [the NSPS] program [to a state], EPA will evaluate the state programs to ensure that states have adequate capability to enforce the CAA section 111 regulations and provide assurances that they will enforce the NSPS. In addition, EPA retains authority to enforce this NSPS anytime under CAA sections 111, 113 and 114. Accordingly, we can enforce the monitoring, recordkeeping and reporting requirements, which, as discussed under the first factor, are adequate to ensure compliance with this NSPS.[564]

Although EPA retains legal authority to enforce the NSPS where states fail to do so (*e.g.*, because of a lack of funding), EPA has not examined whether EPA itself has the resources to enforce these requirements nationwide without the benefit of Title V permit fees.

It is difficult to imagine how EPA can conclude that publicly taking the cop off the beat by eliminating the principal source of funding for many state enforcement programs will have no effect on compliance rates. Such an assumption is plainly arbitrary and capricious, and unsupported by the record.

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[563] http://www.deq.state.or.us/aq/permit/index.htm (last visited Oct. 24, 2011), attached hereto as Exhibit 167.
[564] 76 Fed. Reg. at 52,753.

Title V permitting also serves to improve compliance by increasing transparency and providing a vehicle where questions of the applicability of the NSPS (and the several exemptions thereto) are identified and resolved. Under EPA's proposal sources would decide these issues with no opportunity for upfront state or federal review or public disclosure of a decision by the source that it believed the standard did not apply.

Third party verification does not obviate the need for Title V fees. The preamble to the proposed rule states that EPA "want[s] to state clearly here that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and EPA."[565] Even if third party verifiers were capable of substituting for government enforcement, EPA has provided no evidence that the cost to industry of third party verifiers sufficient to play this role would be less than the cost of an efficiently structured Title V program.

Thus, Title V protects the environment and ensures compliance with NSPS requirements both by mandating reporting and by funding enforcement programs. Title V also increases compliance is by facilitating judicial enforcement. A Title V program must "provide for judicial review of permitting actions."[566] Another benefit of Title V EPA does not discuss is the fact that Title V permittees are required to submit annual compliance plans and compliance certifications. 42 USC 7661b(b)(1),(2); 40 CFR 71.5(d). Failure to do so, and knowing false material statements in the certifications is subject to criminal penalties. 42 USC 7413(c)(1),(2).

3. EPA overstates the burden of the Title V program

While EPA has understated the benefits of the Title V program, EPA has overstated the burden the program imposes on facility operators. EPA has provided scant and flawed information regarding costs of compliance, ignored ways in which the Title V program may and would likely be streamlined, and provided no information regarding facilities' ability to bear these costs.

EPA begins with an overstated estimate of the costs of compliance. "EPA estimated that the average cost of obtaining and complying with a Title V permit was $65,700 per source for a 5-year permit period, including fees."[567] EPA bases this figure on an "Information Collection Request (ICR) for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07."[568] We have been unable to locate this supporting information in the docket or on EPA's website; only the information request, rather than the conclusions drawn from the responses thereto, appears to be available in the

[565] 76 Fed. Reg. at 52,750.
[566] *Arizona Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1284 (D.C. Cir. 2000) (citing 42 U.S.C. § 7661a(b)(6), (7)), attached hereto as Exhibit 168.
[567] 76 Fed. Reg. at 52,753.
[568] *Id.*

Federal Register.[569] The $65,700 figure apparently represents the average across all facilities subject to Title V, including major sources under the PSD and NESHAP programs, and therefore does not represent the average cost of compliance for non-major sources subject solely to NSPS, such as the facilities being regulated here.[570]

Rather, based upon EPA's "presumptive minimum Title V fee" of $46.00 per ton of Title V pollutant actually emitted,[571] and EPA's statement that VOC emissions from a wellhead controlled with a green completion would be about 2.3 tons,[572] the federal minimum permit fee would be 2.3 times $46, or $105.80 per hydraulic fracturing operation. This cost is not even remotely unreasonable. It is trivial when compared to the value of the product generated, even for "small" operators.

Further, EPA failed to consider other tools to lessen the (already low) cost of Title V compliance. For example, permitting authorities may issue "general permits" encompassing a class of similar sources.[573] Numerous states have adopted general Title V permits for dozens of sectors.[574]

General permits can significantly ease the costs of compliance. In one context, EPA has stated that a normal Title V permit requires 200 hours of "permit renewal" work per year, whereas re-application for a general permit requires only two hours per year.[575] In this circumstance, where EPA has determined that the majority of the Title V monitoring, recording and recordkeeping overlaps with that required by the proposed NSPS, the permit application and renewal hours presumably constitute a large fraction of the burden imposed by Title V. Thus, reducing those hours by a factor of 100 would significantly reduce the costs of Title V compliance. In other cases where EPA has exempted sources from Title V, EPA has done so only after explicitly stating that Title V would remain unnecessarily burdensome even if general permits were used to reduce costs.[576,577] Although we contend that these rulemakings' often-cursory dismissal of

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[569] *See Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; State Operating Permit Regulations (Renewal); EPA ICR No. 1587.07, OMB Control No. 2060–0243*, 72 Fed. Reg. 32,289 (June 12, 2007), attached hereto as Exhibit 169.

[570] *See Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75,325 (Dec. 19, 2005) (discussing limits of the preceding 2004 Information Collection Request).

[571] *See* http://www.epa.gov/airquality/permits/historicalrates.html, attached hereto as Exhibit 170.

[572] RIA at 3-6.

[573] 40 C.F.R. § 70.6(d).

[574] *See Tool Selection Guide: A Review of Permitting Options for Implementing Area Source Rules*, Report to EPA prepared by Industrial Economics, Inc. pp. 17-26 (Nov. 11, 2009) (available at http://www.epa.gov/erp/files/selectionguide.pdf) (cataloguing and summarizing general permit programs in six states), attached hereto as Exhibit 171.

[575] *Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75,341 (Dec. 19, 2005).

[576] *See, e.g.*, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Chemical Preparations Industry*, 74 Fed. Reg. 39,013, 39,021 (Aug. 5, 2009), attached hereto as Exhibit 172, *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Paints and Allied Products Manufacturing*, 74 Fed. Reg. 26,142, 26,152 (June 1, 2009), attached hereto as Exhibit 173.

general permits was inadequate, EPA did not even mention the possibility of using general permits here.

EPA also underestimates industry's ability to bear the costs of Title V compliance. EPA states that "some of the non-major sources that would be subject to the proposed NSPS *may* be small entities that *may* lack the technical resources [sic] and, therefore, need assistance from the permitting authorities to comply with the Title V permitting requirements."[578] EPA purports to support this conjecture by noting the sheer number of annually affected *facilities* (20,000 well completions, 14,000 new controller installations, 500 compressors and 300 storage vessels), but EPA provides no data regarding the number of *businesses* operating these facilities. Thus, EPA's mere speculation that "some" operators "may" be small and "may" lack technical expertise provides no justification for concluding that regulated entities will be unable to bear the costs of Title V compliance. Larger entities have greater financial resources and, perhaps more importantly, economies of scale relating to Title V technical expertise which will drive down the cost of compliance per facility. Here, it is important to recognize that the "technical expertise" that will be required is that needed to comply with the underlying NSPS, not the Title V permit. Small operators with limited technical expertise respecting the performance of low-bleed controllers or dual double dry seals for compressors may need to obtain assistance. However, the Title V permit adds no substantive compliance obligation, it merely makes sure that all Federal obligations applicable to a source can be found in one document. Moreover, in addition to specifically authorizing general permits, the Act also specifically authorizes the issuance of one permit for a facility with multiple sources.[579] Thus, the operator of a well field with 100 wells would only need to get a single general permit in order to comply with Title V permitting requirement.

Whereas EPA provides no information about the number of small entities regulated here, in other recent rulemakings EPA has only held that Title V exemptions were

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[577] See also *Revision of Source Category List for Standards Under Section 112(k) of the Clean Air Act; National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Aluminum, Copper, and Other Nonferrous Foundries*, 74 Fed. Reg. 6,510-01, 6,521 (Feb. 9, 2009), attached hereto as Exhibit 174; *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Nine Metal Fabrication and Finishing Source Categories*, 73 Fed. Reg. 18,334-01, 18,359 (Apr. 3, 2008), attached hereto as Exhibit 175; *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations*, 73 Fed. Reg. 14,126-01, 14,141 (March 14, 2008), attached hereto as Exhibit 176; *National Emission Standards for Hazardous Air Pollutants for Area Sources: Clay Ceramics Manufacturing, Glass Manufacturing, and Secondary Nonferrous Metals Processing*, 72 Fed. Reg. 53,838-01, 53,850 (Sept. 20, 2007), attached hereto as Exhibit 177; *National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving*, 72 Fed. Reg. 38,864-01, 38,875 (July 26, 2007), attached hereto as Exhibit 178.

[578] 76 Fed. Reg. at 52,753. EPA fails to mention that Title V permitting assistance is currently provided as a routine matter by permitting authorities.

[579] See 42 U.S.C. 7661a(c).

warranted when EPA had specific information regarding the proportion of small businesses affected.[580] Here, EPA has provided no information indicating that any appreciable fraction of sources are owned by "small" business entities that lack technical acumen or that have particularly limited ability to bear the costs of Title V compliance.[581]

Here, it is important to recognize that the "technical expertise" that will be required is that needed to comply with the underlying NSPS, not the Title V permit. Small operators with limited technical expertise respecting the performance of low-bleed controllers or dual double dry seals for compressors may need to obtain assistance. However, the Title V permit adds no substantive compliance obligation, it merely makes sure that all Federal obligations applicable to a source can be found in one document.[582]

In summary, EPA has ignored the role Title V fees play in ensuring NSPS compliance; failed to demonstrate that, absent fees, states or EPA have capacity to enforce the NSPS; and failed to show that Title V imposes burdens that are disproportionate to its benefits or that regulated facilities are unable to bear. Accordingly, EPA must withdraw its proposal to exempt well completions, compressors, pneumatic devices and small storage tanks from the requirement to seek and hold Title V operating permits.

4. EPA's Third Party Verification Plans are Ill-Defined

EPA briefly proposes a "third party verification" program as a "complement" to the annual compliance certification. [583]EPA has not, however, provided a coherent explanation as to the role these verifiers would play. Without a clear picture as to the role of these private actors, it is impossible to comment on the appropriateness of their use. We accordingly object to adoption of a third-party verification system for the

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[580] *Standards for Paints and Allied Products Manufacturing*, 74 Fed. Reg. at 26,152 ("almost all of the approximately 2,190 paints and allied products manufacturing facilities that would be affected by this proposed rule are small entities; over half have nine or fewer employees."), attached hereto as Exhibit 179; *Standards for Aluminum, Copper, and Other Nonferrous Foundries*, 74 Fed. Reg. at 6521 ("approximately 98 percent of the plants that would be affected by the proposed rule are small businesses, most with fewer than 50 employees and about 25 percent or more with only one to four employees."), *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations*, 73 Fed. Reg. 14,126-01, 14,141 (March 14, 2008) ("nearly all of the approximately 2,900 plating and polishing facilities affected by this proposed rule are small businesses, some with as few as one or two employees.").

[581] Although EPA's prior rulemakings have looked to the raw number of businesses and looked to the fraction of this number constituted by "small" business, a better approach would be to look to the fraction of *facilities* owned by small business.

[582] EPA also fails to mention that Title V permitting assistance is currently provided as a routine matter by permitting authorities.

[583] 76 Fed. Reg. at 52,750.

proposed O&G NSPS at this time. We nonetheless alternatively offer the following comments on third party verification generally.

A threshold question, which EPA has not answered, but must address, is why it proposes to use third party verification at all in this context. EPA "state[s] clearly [in its proposal] that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and EPA."[584] EPA has not identified any function that third party verifiers can perform more effectively, or more cheaply, than can permitting authorities. Thus, there is no apparent reason to require industry to fund third party verifiers through some yet un-described system instead of requiring industry to fund verification by the permitting agencies through title V. We are particularly troubled by the possibility that EPA sees its vague proposal for third-party verifiers as justification for exempting wellheads, compressors, pneumatic devices and small storage tanks from title V. To be clear, the proposal itself explicitly disclaims such reliance. EPA has stated that third party verification would not displace government inspection and regulation, and EPA's discussion of the proposed title V exemption does not refer to third party verifiers. Nonetheless, we wish to highlight the fact that EPA cannot and should not substitute an undefined private framework for an established regulatory regime with well-defined provisions for public disclosure and judicial enforcement.

A second issue, which EPA recognizes, is that "third party verification paid for by industry" presents a potential conflict of interest that can compromise the verification's validity. In the late 1990s, EPA's National Enforcement Investigations Center audits of private LDAR monitoring "show[ed] that the number of leaking valves and components is up to 10 times greater than had been reported by certain re-fineries"; these reports included reports generated by third parties.[585] In light of this history, any proposal for third party verification must, at minimum, address conflicts of interest by incorporating an accreditation scheme and by requiring verifiers to be paid through an industry consortium rather than by individual facilities. For a model accreditation scheme, EPA could look to the California Air Resources Board's accreditation of third party verifiers adopted pursuant to California's greenhouse gas reporting rule.[586] EPA could similarly accredit and oversee third party verifiers, requiring that only accredited verifiers be used. EPA could also require that third party verifiers be paid by an industry consortium, rather than by individual facilities, attenuating the financial connection and accompanying conflict. EPA must further explore schemes under which the permitting authority, rather than the facility operator, selects the verifier to be used in particular

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[584] *Id.*

[585] EPA Office of Regulatory Enforcement, *Proper Monitoring Essential to Reducing 'Fugitive Emissions' Under Leak Detection and Repair Programs* (Oct. 1999)*, available at* http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/emissions.pdf, attached hereto as Exhibit 180.

[586] *See* www.arb.ca.gov/cc/reporting/ghg-ver/ghg-ver.htm.

cases. If it moves forward, it must use such a model, or explain why it has failed to do so.

If third party verifiers are used, any information they collect should be as fully available to the public, comparable to information collected by EPA. EPA asks whether third party verifiers could serve as a "clearinghouse for notifications, records and compliance certifications."[587] Any such clearinghouse should be fully available online and provide the general public with full access to the collected data, on a searchable and tabular basis.

Finally, we address the roles EPA has proposed for third party verifiers. We have no objection to above-mentioned "clearinghouse" role, provided that the role does not substitute for government verification and that all data is publicly available. We nonetheless disagree with EPA's suggestion that with such a clearinghouse, "notifications of well completions could be submitted with an advance period much less than 30 days that could make a 2 day follow-up notification unnecessary."[588] EPA has not explained how the clearinghouse would obviate the need for such advanced notification. Although notification through a clearinghouse might be more efficient than other notification methods, the role of advanced notification is to enable states and EPA to inspect well completions as they occur, and significant advanced notice is likely to facilitate scheduling of such inspections. An online clearing house would not solve this scheduling problem.

The second role EPA suggests for third-party verifiers is to assist states and EPA in "review[ing] and verify[ing]" data submitted through EPA's electronic reporting tool. In light of the conflict of interest mentioned above, private verifiers must not displace government review and enforcement of NSPS requirements. Absent a more definite proposal, we oppose using third-party verifiers in this way.

Third, EPA alludes to using third party verifiers to inspect facilities in the field. This role is implied by EPA's statement that third-party verification can be useful in light of the geographically dispersed and remote nature of facilities, although it is not directly discussed by EPA. Provided that third-party verifiers are limited to collection of unarguably objective data, such as the type of compressor installed, we do not object to this *type* of verification. Nonetheless, because EPA has not proposed a specific framework for verification, and because the implementation details are critically important, we oppose using third party verifiers in this role until EPA offers a more detailed proposal for public comment.

B. The Affirmative Defense

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[587] 76 Fed. Reg. at 52,750.
[588] *Id.*

EPA unlawfully proposes to promulgate an "affirmative defense" to penalties due to a malfunction.[589] This would create a new loophole in the standards and is unlawful. It also would have harmful consequences for local communities affected by oil and gas production, and will greatly reduce the deterrent impact of the proposed standards.

The statute makes clear how the courts are to assess civil penalties, whether a case is brought by EPA or a citizen.[590] Congress plainly intended citizens to be able to enforce emission standards under the CAA using the full range of civil enforcement mechanisms available to the government. EPA's rule proposal, by shifting this careful balance and contravening these mandates, violates the CAA.

The affirmative defense that EPA proposes to allow in case of malfunctions goes directly against congressional intent in two ways. First, Congress expressed a clear intent as to how judges should determine the size of civil penalties whenever they are sought and thus Congress flatly barred EPA from limiting when civil penalties can be assessed.[591] In this proposal, EPA acts outside of its delegated authority to limit civil penalties available in citizen suits or its own enforcement actions. Second, the proposal will impermissibly chill citizen participation, and the ability to win an effective, deterrent remedy, in CAA enforcement actions.

The affirmative defense is fatally flawed because EPA does not have the authority to decide when civil penalties will not be allowed. The CAA itself spells out the only limits that Congress intended to impose on citizens' ability to seek and recover penalties in enforcement suits under CAA § 304, 42 U.S.C. § 7604.[592] By attempting to impose additional agency-created limits, EPA exceeds its authority.

Congressional intent on civil penalties is clear—they are a remedy available for enforcement by citizen plaintiffs, and the Act gives judges a list of factors to consider in assessing them.[593] As such, EPA cannot interpret the statute to contravene that intent.[594] By attempting to rewrite this provision, via regulation, EPA has done just that.

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[589] *See* 76 Fed. Reg. at 52,807 (proposing 40 C.F.R. § 60.5415(h)).
[590] 42 U.S.C. § 7413(e).
[591] *See Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984), attached hereto as Exhibit 181.
[592] *See* 42 U.S.C. § 7413(e).
[593] *Sackett v. EPA*, 622 F.3d 1139, 1146-47 (9th Cir. 2010) *cert. granted in part,* 131 S. Ct. 3092 (2011) (in interpreting analogous penalty provision of Clean Water Act, 33 U.S.C. § 1319(d) holding that "the civil penalties provision is committed to judicial, not agency, discretion."), attached hereto as Exhibit 182.
[594] *See Chevron*, 467 U.S. at 842-43; *see also Barnhart v. Sigmon Coal Co.*, 534 U.S. 438, 462 (2002) ("We will not alter the text in order to satisfy the policy preferences of the Commissioner."), attached hereto as Exhibit 183; *North Carolina v. EPA*, 531 F.3d 896, 910 (D.C. Cir. 2008) ("All the policy reasons in the world cannot justify an agency reading a substantive provision out of a statute."), attached hereto as Exhibit 184.

The CAA grants EPA minimal discretion that only applies to administrative penalties, allowing EPA to "compromise, modify, or remit, with or without conditions, any administrative penalty which may be imposed under [subsection 113(d)]."[595] However, there is no similar grant of authority to EPA to compromise, modify or limit civil penalties that a court may impose under section 113(e) or section 304. Section 304(a), 42 U.S.C. § 7604(a), grants courts the sole authority "to apply any appropriate civil penalties" in citizen suits. The explicit reference to EPA's ability to modify penalties in one subsection and its absence in the other subsection of the same provision can only be understood as an intentional decision by Congress that EPA may not contravene by rule.

If a local community group sued a covered facility for a violation of the emission standards, the owner might argue that it is exempt from paying civil penalties so long as the owner satisfied the requirements set forth in EPA's proposed affirmative defense regulations.[596] The owner must not be able to evade civil penalties that apply when the congressionally mandated factors in the statute are met.[597,598] It is improper for a court to fail to consider these factors, or to fail to make its own determination of what civil penalties are "appropriate" under CAA § 304(a), and EPA must not ask a court to ignore its legal duty.[599] Notably, courts interpreting the analogous provision of the Clean Water Act have held that the statutorily enumerated factors cannot warrant elimination of a penalty.[600,601] *A fortiori* it is impermissible for EPA to attempt to displace those

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[595] 42 U.S.C. § 7413(d)(2)(B).

[596] *See* 76 Fed. Reg. at 52,813-14, 52,829-30 (proposing 40 C.F.R. §§ 63.761-62, §§ 63.1271-72).

[597] *See* 42 U.S.C. § 7413(e) (listing factors).

[598] Note that the proposed exemption would also be barred under *Chevron* step two or found to be arbitrary and capricious since, even if there exists some slight ambiguity, it is unreasonable to construe the statute as permitting EPA to short-circuit the consideration of specifically listed factors. *See Chevron*, 467 U.S. at 843 (explaining that if the statute does not answer the question at issue, "the question for the court is whether the agency's answer is based on a permissible construction of the statute"); *S. Coast Air Quality Mgmt. Dist. v. EP*A, 472 F.3d 882, 895 (D.C. Cir. 2006) ("We further hold that EPA's interpretation of the Act in a manner to maximize its own discretion is unreasonable because the clear intent of Congress in enacting the 1990 Amendments was to the contrary."), attached hereto as Exhibit 185; *see also Gen. Instrument Corp. v. F.C.C.*, 213 F.3d 724, 732 (D.C. Cir. 2000) (explaining that "an arbitrary and capricious claim and a *Chevron* step two argument overlap"), attached hereto as Exhibit 186; *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (explaining that agency acts in arbitrary and capricious manner if it fails to consider "relevant factors" or "entirely fail[s] to consider an important aspect of the problem"), attached hereto as Exhibit 187. By "upset[ting] the statutory balance struck by Congress," as discussed above, the affirmative defense is unreasonable under *Chevron* step two. *Int'l Alliance of Theatrical & Stage Employees v. N.L.R.B*, 334 F.3d 27, 35 (D.C. Cir. 2003), attached hereto as Exhibit 188.

[599] It is also improper for EPA to fail to consider the section 113(e)(1) factors in situations in which it is setting the penalty. CAA § 113(e)(1), 42 U.S.C. § 7413(e)(1); *see also N.Y. Cross Harbor R.R. v. Surface Transp. Bd*., 374 F.3d 1177, 1184 (D.C. Cir. 2004) (holding that "Board's failure to balance the competing interests . . . requires" vacatur of agency action).

[600] *See United States v. Lexington-Fayette Urban County Gov't*, 591 F.3d 484, 488 (6th Cir. 2010) (collecting cases from the Fourth, Sixth, Ninth, and Eleventh Circuits), attached hereto as Exhibit 189.

factors or in any way alter their significance by creating a bar to penalties if certain agency-defined considerations are met instead.

Citizen participation in CAA enforcement also will be hindered, in violation of citizens' rights to protect themselves from pollution and in direct conflict with congressional intent. The affirmative defense would likely be used on a routine basis by polluters seeking to avoid penalties, just as the malfunction exemption was. As a result, citizens who seek the assessment of civil penalties against polluters in order to protect themselves and achieve the Act's goals may be forced to engage in fact-intensive disputes over the cause of emission violations and adequacy of responsive measures – an outcome Congress intended to prevent with the simple straightforward enforcement and penalty provisions in the Clean Air Act. As a result, enforcement of the Act could suffer, for civil penalties provide a powerful deterrent to violators as Congress intended. As the Supreme Court explained: "To the extent that they [civil penalties] encourage defendants to discontinue current violations and deter them from committing future ones, they afford redress to citizen plaintiffs who are injured or threatened with injury as a consequence of ongoing unlawful conduct."[602,603]

Thus, the affirmative defense also runs counter to two clearly expressed intentions of Congress: (1) the burden it places on citizens makes it less likely that they will enforce the Act;[604] and (2) several of the factors at issue in the affirmative defense undercut Congress's intent that citizen suit enforcement should avoid re-delving into "technological or other considerations."[605] Both result from the technical burden EPA imposes on citizens with the affirmative defense, and both render the defense impermissible.

In addition to these problems, there is simply no need for an affirmative defense to penalties to be written into the regulations and cause the harm that will result. EPA has discretion to decide what cases to prosecute, to consider settlements, and to request

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[601] In another proceeding, EPA has argued that it may promulgate such an affirmative defense as an interpretation of the 'catchall' provision of CAA § 113(e)(1), which directs "the Administrator or the court, as appropriate," to consider the enumerated factors and "such other factors as justice may require." Partial Approval of Texas SIP, 75 FR 68,989, 68,999 (Nov. 10, 2010), attached hereto as Exhibit 190. As noted above, this provision represents a Congressional delegation of discretion to judges, not EPA. *United States v. Mead Corp.*, 533 U.S. 218, 226-27 (2001) (agencies enjoy *Chevron* deference where it is reasonable to presume that Congress delegated interpretive authority to the agency), attached hereto as Exhibit 191. Even if EPA has authority to interpret "other factors," the affirmative defense would require a court to elevate these additional factors above those enumerated by the statute.

[602] *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs.*, 528 U.S. 167, 186 (2000), attached hereto as Exhibit 192.

[603] S. Rep. 101-228, at 373 (1989), *as reprinted in* 1990 U.S.C.C.A.N. 3385, 3756, attached hereto as Exhibit 193.

[604] *See, e.g.*, *Pennsylvania v. Del. Valley Citizens' Council for Clean Air*, 478 U.S. 546, 560 (1986), attached hereto as Exhibit 194.

[605] *NRDC v. Train*, 510 F.2d 692, 724 (D.C. Cir. 1974)

civil penalties in a case-by-case manner, as long as it acts consistent with the Clean Air Act to protect clean air as its top priority.[606] Promulgating this affirmative defense is equivalent to giving polluters "get out of jail free" cards for serious emission exceedances and MACT violations. Polluters are likely to claim that any violation of the standard is due to a malfunction in order to evade the requirements. Allowing polluters to evade financial penalties – which are the real teeth of the standards – through this type of measure is likely to lead to polluters simply ignoring or factoring potential standard violations into their cost of doing business, rather than actually trying to prevent malfunctions and violations of the standards as a way to avoid financial losses from the application of penalties.

Assuming *arguendo* that EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, EPA is required by statute to also promulgate the following provisions:

1. A specific amount of compensatory penalties must apply to each reported malfunction (consistent with the Act). These funds must be dedicated to enforcement, inspections, and monitoring in the local community around the specific facility, to create greater assurance that malfunctions will not happen again.

2. EPA must modify the regulations so that the affirmative defense cannot be used by a specific facility or company more than once within a set period of time, such as 10 years. The affirmative defense must become automatically unavailable to a facility that has previously had a malfunction within the last 10 years, to ensure that this defense does not swallow the value of the standards.

3. EPA must promulgate specific public reporting and notification requirements for malfunctions, or any emission exceedance that occurs of which an operator is aware. Specifically, EPA must require that when a facility provides EPA with a notification of a malfunction or emission standard exceedance under the regulations, this notice will be made publicly available on EPA's website within 14 days. In addition, EPA must promulgate the requirement that when such notification is made, the facility must also provide for community notification of the malfunction or emission standard exceedance within 2 business days, through an appropriate public forum that is designed to reach residents who live near the facility, including but not limited to a notice on the facility's own website (if it has one), a written notice to the local municipality and local school district, a press release to the local newspaper, radio, and TV news

[606] *See* 42 U.S.C. § 7401.

> station that contains information community members may need to protect themselves and their families from the additional air pollution.

Commenters urge EPA not to adopt an affirmative defense that undermines citizen rights and remedies under the Clean Air Act. People living near oil and gas facilities are exposed to unacceptably high levels of hazardous air pollution that no one should have to face simply because of where they live. EPA may not lawfully use a regulation to take away a right granted to citizens by Congress. EPA must work to expand and protect the ability of people harmed by air pollution to seek all appropriate and available forms of relief in court. EPA must not retract or weaken citizen rights and remedies, as this proposal does, by making it more difficult for people to win meaningful relief from facilities that have released toxic air pollution into their communities for years.

Commenters support EPA's proposal for electronic reporting of data.[607] If EPA were to finalize any form of an affirmative defense, it must require that all reports related to that defense be submitted electronically and EPA must also make these reports available immediately to the public on its website, as discussed above. As the public has a right to all collected reports under the Clean Air Act, 42 U.S.C. § 7414(c), EPA must require immediate disclosure to the public on the Internet, without the need for any person to submit a FOIA request for such a report.

VII. EPA HAS OVERESTIMATED THE COSTS AND UNDERESTIMATED THE BENEFITS OF ITS PROPOSAL

A. EPA's Consideration of Costs Under Section 111 and the Regulatory Impacts Analysis

As we demonstrate above, EPA's proposal is based upon readily achievable methods, the costs of which are reasonable. In this section of our comments, we delve deeper into the costs and benefits of the rule, demonstrating that the rule has significantly greater economic and social benefits than EPA suggests.

EPA must, under section 111 of the Act, issue standards of performance that

> reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the *cost of achieving such reduction* and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[608]

[607] 76 Fed. Reg. at 52,748, 52,825, 52,840.
[608] 42 U.S.C. § 7411(a)(1) (emphasis added).

Under this plain language, EPA must consider the costs of control, i.e., those that the sector incurs to achieve the emission reduction from the affected facility to which the standard applies, in setting a standard of performance; it may not base its standard-setting on a broad-ranging cost-benefit analysis.[609]

Below, we demonstrate that these costs of control are frequently over-stated with respect to the proposal. EPA regularly uses very conservative data to calculate costs. A more realistic assessment would show that the rule has substantially lower costs than EPA acknowledges. We also show that EPA's estimates of the rule's direct financial benefits, through the capture of natural gas and condensate, are low. The natural gas prices EPA uses to calculate these benefits are far lower than all other projections. EPA must use a realistic gas price in its analysis, which would accurately value the savings that the standards will achieve. Doing so will significantly lower the cost of control EPA uses in its standard setting process.

We also address EPA's discussion of the benefits of the rule, which it developed in its Regulatory Impact Analysis (RIA), which did include a cost-benefit analysis, as part of its compliance with Executive Order 12866, "Regulatory Planning and Review."[610] Importantly, while the RIA provides important information on the impacts of the proposed rule, EPA's standard-setting duties and authority are derived under section 111 of the Act and its decision must be made within the confines of that authority, although it may be described and informed by the RIA.[611] As such, our critique of the RIA largely addresses how EPA and other government actors are to understand the economic impact of the rule. It does not bear directly on the standard setting process itself.

With regard to the RIA, we show that EPA has not properly accounted for the substantial benefits the rule creates by capturing methane as a co-benefit of VOC regulation. These co-benefits include both substantial reductions in climate change-causing pollution, and a reduction in ground-level ozone, of which methane is a precursor. While EPA provided an estimate of the climate-linked financial benefits of the methane reductions in the RIA (an estimate of the "social cost" of methane), it chose "not to compare these co-benefit

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[609] *Id.; see also Motor & Equipment Mfrs. Assn. v. EPA*, 627 F.2d 1095, 1117-18 (D.C. Cir. 1979) (in interpreting "cost of compliance" for vehicle emission standards under section 202(a)(2), rejecting industry's claim that EPA must consider broad social costs), attached hereto as Exhibit 195; *American Textile Manufacturers Inst. v. Donovan*, 452 U.S. 490, 510-11 (1981) (explaining that "Congress uses specific language when intending that an agency engage in cost-benefit analysis."), attached hereto as Exhibit 196. We note that section 111(h) imposes identical cost of control considerations upon EPA, and so our discussion of the cost of control of EPA's standards applies to those controls as well. *See* 42 U.S.C. § 7411(h)(1).

[610] *See* 76 Fed. Reg. at 52,794 (citing 58 Fed. Reg. 51,735 (Oct. 4, 1994)).

[611] *See* E.O. 12866 Section 10, "Judicial review," attached hereto as Exhibit 197. "Nothing in this Executive order shall affect any otherwise available judicial review of agency action. This Executive order is intended only to improve the internal management of the Federal Government and does not create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States…."

estimates to the costs of the rule for this proposal," but rather only to explore methane co-benefits in supporting documents as an "interim method."[612] For the reasons set forth below, we believe that EPA must include the methane co-benefits in its comparison of the proposed rule's costs and benefits. We also propose ways in which the social-cost-of-methane assessment can be improved by EPA in this rulemaking, and corrections and improvements to the underlying "social cost of carbon" analysis that should be made by the Interagency Working Group on the Social Cost of Carbon. We also discuss substantial ozone reduction co-benefits that will occur with the methane reductions, which will produce substantial public health and welfare improvements. Without these corrections and improvements, the figures provided by EPA significantly underestimate the social benefits of methane reductions from the proposed rule.

B. EPA Overestimated the Costs of Its Proposed Rule

1. The Costs of the Standards are Reasonable Under Section 111

In its evaluation of costs supporting the proposed rule under section 111, EPA assessed the cost of control for various affected facilities and technologies, finding the costs associated with each adopted measure to be reasonable. It then took into account, for control technologies capturing natural gas, the additional savings due to resale of captured gas where such resale is feasible. We compared these EPA estimates to figures from other EPA reports and industry information, and generally conclude that EPA's estimates range from reasonable to very conservative. In some instances, EPA overestimates the cost of control; in others, it underestimates the volume of gas reduced for a given cost; and in some cases it both overestimates the costs and underestimates the emissions controlled. When added to EPA's underestimation of the price of natural gas, taking account of these factors supports that the proposed rule's costs are lower than EPA recognizes.

Our focus throughout is upon the cost per ton of emission reduction, as this is the metric that EPA used to show that the proposed standards impose reasonable costs, consistent with section 111's required considerations.[613]

Our assessment is based on:

- Quantitative cost of control comparisons between EPA's estimates and other estimates, by control technology;
- Qualitative considerations that contextualize and add to the above comparisons; and

[612] RIA at 4-33.
[613] We do not necessarily agree that a dollars-per-ton-of-pollutant-controlled metric is the appropriate gauge for costs under section 111(a)(1), as some measures may impose reasonable costs within the meaning of the statute even if they exceed some EPA threshold for cost effectiveness.

- Analysis of the forecasted price of natural gas forecasted, and its divergence from EPA's estimate.

Although we have done our best to unpack EPA's assumptions, EPA's cost calculations and methodology are not transparent. EPA must more clearly describe its "cost of control" methodology in the final rule, including its calculations and sources.

2. Quantitative comparison of the cost of control technologies

For each technology, we have compared available EPA TSD estimates to other sources, including: Past EPA reports and presentations particularly related to its Natural Gas STAR program; EPA's Methane to Markets Partnership (recently transformed into the Global Methane Initiative) presentations derived from methane reduction successes in the US and thirteen other countries; independent company reports; independent consultant reports; and journal publications.

Different data sources and analyses report costs in different ways (e.g., yearly profit, net present value, payback). We have tabulated the available data to facilitate a like-for-like comparison. Where helpful, we have translated reported data in ways that best fit into the table. But, in many instances the available information was insufficient to populate the entire cost-effectiveness breakdown; in these instances, we have still included all available data. Where possible, we estimated cost per year (or per device, as applicable), savings per year (or per device), profitability per year (or per device) and the payback of the investment. We used the latter two metrics as prime indicators of the cost-effectiveness of the control technologies. These are highlighted in the tables below.

For natural gas prices, where data for the volume of natural gas savings was available, we assumed the price of natural gas to be $4/Mcf, to align with EPA's calculations. When volumes were not directly available in the data sources, in most cases we scaled these savings to what the savings would have been at a natural gas price of $4/Mcf. In some cases, we had insufficient data or visibility to scale the savings and left it unaltered (but in these instances noted the likely price of natural gas applicable). Later in this document, we discuss the likelihood of prices being different from $4/Mcf.

We make a general observation here that in several instances we have quoted from EPA and other reports from the recent past. Despite having been published as much as five years ago, these reports are valuable because they provide transparent and well-documented examples of cost-effective and profitable emissions reductions that have been achieved. In contrast, we find in general that the EPA TSD estimates lack transparency. In a few instances, sources for the analysis are not entirely clear. In other instances where sources are mentioned, the additional analysis conducted using those sources are not sufficiently explained to facilitate independent verification. In yet other instances, it is unclear whether some of the estimates are based on past achievements. Additionally, as explained in more detail in following sections, the estimates from past

reports provide numerous examples of controls being much more cost-effective than the EPA TSD estimates, suggesting, by contrast, that the latter is conservative.

a. Green Completions

We assess EPA's estimated cost of control of green completions to be reasonably realistic.

Table 4: Cost of control analysis of well completions and recompletions

			#	$	Mcf	$ / Mcf	$	$	$ / well	Years	$ / well
Source	**Year**	**Type**	**# wells**	**Total cost per well (capital, operational)**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Condens-ate savings**	**Total revenue per well**	**Payback**	**Profit per well**
EPA - NSPS TSD [614]	2008	Min	1	2,418							
EPA - NSPS TSD	2008	Max	1	74,860							
EPA - NSPS TSD	2008	Average	1	29,713	8,258 [a]	4.00	33,032	2,380	35,412	0.84	5,699
EPA,[615]	2005	Min	1	7,000	7,700	4.00	30,800		30,800	0.23	23,800
EPA	2005	Max	1	15,000	7,700	4.00	30,800		30,800	0.49	15,800
Devon Energy [617,618]	2004	Average	~400[b]	8,700	11,740	5.00	58,700		58,700	0.15	50,000
BP [619,620,621]	2007	Average	106	12,264	7,500	4.00	30,000	6,321	36,321	0.35 - 0.70	24,057
Williams [622]	2006	Average	1177	14,444	22,515	4.00	90,059 [c]		90,059	0.16	75,616

EnCana [623]	??	Average	??	??			??		??	< 1.00	190 M + over many wells
Anadarko [624]	2008	Average	613			5.00	??		??		16,803
ICF [625]	2009	Average	??							0.25	

[a] 142.7 tons of methane; production quality natural gas is approx. 83% methane (EPA TSD page 5-16); 0.0208 tons per Mcf
[b] Calculated from estimated average emissions per well, given that total emissions reductions was ~4.8 Bcf in 2005
[c] Scaled down from revenues based on a historically higher natural gas price, assumed to be $6/Mcf

In its NSPS Technical Support Document (TSD)[614], EPA estimates that the average green completion costs about $29,700 per completion, and saves approximately 8,300 Mcf of natural gas per completion (valued at $33,000, at $4/Mcf) and a modest volume of condensates.

Based on recent estimates from select company operations and EPA's 2005 reports of achieved emissions reduction,[615] we estimate that a green completion would typically cost $7,000 - $15,000 per completion. The savings from captured natural gas vary quite significantly among different company reports. We note that the average natural gas savings of 7,700 Mcf of natural gas per well from EPA's 2005 estimates is consistent with the EPA TSD's average savings estimates.

Many different companies[616] have reported profitable use of green completions, although the magnitude of profitability varies:

- In 2004, Devon Energy reported an average incremental cost to perform a green completion of $8,700 per well at its Texas Fort Worth Basin operations. Devon estimated that after paying out this cost, it yielded a profit of $50,000 per well by selling the captured gas to market, estimating that it achieved a total emission reduction of 6.16 Bcf at its operations in year 2005; 78 percent of the methane captured (4.8 Bcf) was attributed to green completion methods.[617,618]
- BP reported an initial investment cost of $1.4 million to purchase a portable three-phase separator, sand trap, and tanks to conduct green completions.[619] By 2005, BP completed 106 wells using this equipment and reported an average gas recovery of 0.35 Bcf/year and condensate recovery of 6,700 bbls/year. The company's investment paid out in nearly two years; thereafter, the equipment

[614] EPA NSPS TSD, pages 4-15 – 4-18.
[615] EPA Natural Gas STAR, *Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas*, November 1, 2005, attached hereto as Exhibit 198. EPA reports costs of $1,000 to$10,000 per well (in November 2005 document). However, the costs use in this report are higher ($7,000 - $15,000 per well), and more conservative, because this data relies on cost estimates provided by Devon, BP and Williams operating experience (in New Mexico).
[616] Some of these individual reports may have been included as part of EPA's industry-wide statistics, but there remains some uncertainty as to whether and how these examples have been assimilated, Therefore these examples serve as specific instances of the successful implementation of these technologies.
[617] EPA, ExxonMobil Production Company, and American Petroleum Institute, Green *Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop*, September 21, 2004, attached hereto as Exhibit 199.
[618] Devon Energy, *EPA Natural Gas STAR Program Presentation*, March 2007, attached hereto as Exhibit 200.
[619] EPA and Devon Energy, *Reduced Emissions Completions (Green Completions), Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop*, Casper, Wyoming, August 30, 2005, attached hereto as Exhibit 201.

netted a profit of at least $840,000 per year.[620] Later, in 2007, BP reported that green completions had netted a profit of $3.4 million, for an investment of $1.2 million, with a payout of 0.7 years, and a capture of 130 Mt of methane per well.[621]

- Williams reported $159 million in revenue from green completions in its Colorado Piceance Basin Operations from 2002 to 2006, spending $17 million to achieve that revenue, for a net profit of $142 million.[622] Assuming these savings were on average due to a natural gas price of $6/Mcf, the savings have been scaled down for a $4/Mcf price. Williams' economic data was based on 1,177 wells and an average gas recovery of approximately 91 percent.
- EnCana Corporation, the largest natural gas producer in North America, reported results from its Jonah Field in Wyoming. Jonah produces 1.5 percent of United States daily gas needs. EnCana reported[623] that green completion methods were extremely profitable in the Jonah field, yielding a Net Present Value (NPV) of more than $190 million. EnCana's initial investment in the portable REC equipment for the Jonah Field paid out in the first year.
- Anadarko reported an increased operating profit of $10.3 million/year for the period of 2006 to 2008 due to green completions on an average of 613 wells per year. [624] Anadarko based these calculations on a $5/Mcf natural gas price.
- In a 2009 study conducted for New York State, ICF Incorporated found that equipment payouts were as short as three months. ICF also found that companies made more than $65 million in profits when they elected to conduct green completions in 2005.[625]

In sum, our analysis shows that EPA's well profitability and payback assessments are reasonably realistic, even slightly conservative. The TSD has generally slightly higher estimates of the cost of Green Completions than other sources listed in Table 1. The natural gas savings estimates are roughly consistent with other estimates, which in effect include surveys of over 2,000 wells. We underscore that Green Completions are profitable with an average payback of less than one year.

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[620] BP's profit was based on gas at $1.99 Mcf and condensate at $22/bbl. Gas and condensate prices are substantially higher in 2010; thus, this is a very conservative profit estimate.

[621] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007, attached hereto as Exhibit 202.

[622] The Williams Companies, "Reducing Methane Emissions During Completion Operations – Economics Volume Recovered." Williams Production RMT – Piceance Basin Operations. 2007 Natural Gas Star - Production Technology Transfer Workshop. September 11, 2007, attached hereto as Exhibit 203.

[623] EPA and ICF International, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009, attached hereto as Exhibit 204.

[624] Methane to Markets, Reduced Emission Completions/Plunger Lift and Smart Automation, Oil & Gas Subcommittee Technology Transfer Workshop, Monterrey, Mexico, January, 2009.

[625] ICF Incorporated, Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program, prepared for New York State, August 5, 2009, attached hereto as Exhibit 205.

b. Low-Bleed Pneumatic Controllers

We assess EPA's estimated cost of control of low-bleed pneumatic controllers to be reasonably realistic.

Table 5: Cost of control analysis of replacing high-bleed pneumatic controllers with low-bleed pneumatic controllers

			#	$	$ / yr	Mcf	$ / Mcf	$ / yr	$ / yr	$ / yr	Years	$ / yr
Source	**Year**	**Type**	**# devices**	**Total cost per device**	**Annualized cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Maintenance, operational savings per year**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA - NSPS TSD [626]	2008	Min	1	158	23[a]							
EPA - NSPS TSD	2008	Max	1	1,852	264							
EPA - NSPS TSD	2008	Average	1	165	24	375[b]	4	1,500		1,500	0.11	1,477
EPA [627,628,629]	2005	Average	1	250[c]	36	180[d]	4	720	1,100	1,820	0.15 - 0.40[e]	1,784
EPA Lessons Learned[630]	2006	Average	1	275[f]	39	125[g]	4	500	50	550	0.50	511
BP [631]	2005	Average	11,500	174[c]	25	296[h]	4	1,183	726	1,909	0.09	1,884

[a] EPA assumes a lifetime of 10 years and a discount rate of 7% (NSPS TSD page 5-16, 5-17)
[b] Using the average value of $ savings (NSPS TSD page 5-16); calculated natural gas volume is consistent with TSD value quoted
[c] Assumes half the value of a retrofit
[d] Based on average natural gas savings of 0.5 Mcf/day (as reported in sources)
[e] Range between calculated value and half the reported value of 9 months for a retrofit
[f] Average of $210 and $340 per device
[g] Average of 50 and 200 Mcf/year
[h] 11,500 wells saved 3.4 Bcf/year

In its NSPS TSD,[626] EPA analyzes the costs for a range of low-bleed and high-bleed pneumatic controllers, and estimates that the average cost of a low-bleed pneumatic controller is $165 more per controller than an equivalent high-bleed pneumatic controller. This is the differential cost of installing low-bleed devices instead of high-bleed devices. EPA also estimates an average of $1,500 per year in natural gas savings from reduced emissions per controller.

Our estimates were based on retrofitting or replacing high-bleed with low-bleed pneumatics, due to the availability of data for these scenarios. These projects would cost more than simply choosing low-bleed equipment instead of high-bleed equipment at a new installation. We assumed that the total cost of retrofitting pneumatics was two times the differential cost of installing a low-bleed device instead of a high-bleed device. In order to facilitate a like-for-like comparison with EPA's estimates, we thus divided the retrofit/replacement costs by two to compare to EPA's figures. This is likely to be a conservative estimate.

Based on EPA reports from 2005, retrofitting a high-bleed pneumatic with a low-bleed pneumatic device costs an estimated $500 per controller on average and has a payback of 9 months. The average annual natural gas savings are about $700, and operational savings are conservatively on average $500 per controller.[627,628,629] Operational savings arise mainly from reduced maintenance costs for low-bleed devices. For instance, high-bleed devices tend to be based on older technology and require more maintenance. Also, if operated in enclosed environments high-bleed devices may present a safety hazard and require regular monitoring. The retrofit or complete replacement of worn units can provide better system-wide performance and reliability, and improve monitoring of parameters such as gas flow, pressure, or liquid level.

An EPA Lessons Learned report from 2006 also reports economics consistent with the above, but with smaller operational and maintenance savings. [630] The EPA TSD's overall economic estimates that are derived from this Lessons Learned document, are more positive than estimates directly from the Lessons Learned document due to updates from vendor research.

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[626] EPA NSPS TSD, pages 5-14 – 5-16.

[627] USEPA and Occidental Oil & Gas Corporation, *Methane to Markets, Methane Recovery from Pneumatic Devices, Vapor Recovery Units and Dehydrators*, October 6, 2005, attached hereto as Exhibit 206.

[628] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[629] Journal of Petroleum Technology, *Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*, June 2005, attached hereto as Exhibit 207.

[630] *Lessons Learned from Natural Gas STAR Partners – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, 2006, attached hereto as Exhibit 208.

BP has reported that it replaced 11,500 high-bleed pneumatic instruments with low- or no-bleed instruments in six states, during the period of 1999 to 2002, capturing 3.4 Bcf/year.[631] The program yielded a net present value of $65 million for a capital investment of $4 million for all 11,500 controllers.

In sum, we find that EPA's cost, cost-effectiveness, profitability and payback assessments are broadly consistent with our estimates, and we consider EPA's estimates to be realistic, so as to support low-bleed pneumatic controllers as the basis for the final performance standards. We note however that our estimates may be slightly conservative as they are based on half the cost of retrofitting or replacement, which is probably higher than the cost of installing a low-bleed device instead of a high-bleed device. Importantly, the data generally supports that replacing high-bleed with low-bleed devices is highly profitable with a very short payback, sometimes within a small number of months.

c. Instrument Air Pneumatic Controllers

We assess EPA's estimated cost of control of conversion to instrument air pneumatic controllers to be conservative. EPA's proposal is better supported than the agency acknowledges.

[631] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007.

Table 6: Cost of control analysis of replacing high-bleed pneumatic controllers with instrument air pneumatic controllers

			#	$	$ / yr	$ / yr	$ / yr	Mcf	$ / Mcf	$ / yr	$ /yr	Years	$ / year
Source	**Year**	**Type**	**# devices**	**Total capital cost per device**	**Annual. capital cost of device**	**Maint., operational cost per year**	**Annual. total cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annual. profit per year**
EPA - NSPS TSD [633]	2008	Small	1	16,972	2,416[a]	1,334	11,090[b]	871	4	3,484	3,484	(3.27)	(7,606)
EPA - NSPS TSD	2008	Medium	1	73,531	10,469	4,333	36,877	3,658	4	14,632	14,632	(6.24)	(22,245)
EPA - NSPS TSD	2008	Large	1	135,750	19,328	5,999	80,515	10,161	4	40,644	40,644	(6.61)	(39,871)
EPA - NSPS TSD	2008	Simple average	1	75,418	10,738	3,889	42,827	4,897	4	19,587	19,587	(6.03)	(23,241)
EPA NG STAR [628,629]	2005	Average	1	10,000	1,400	7,500[c]	8,900	5,400	4	21,600	21,600	0.70 - 2.00[d]	12,700
EPA Lessons Learned[632]	2006	Average	1	60,000	8,500	17,700	26,200	20,000	4	80,000	80,000	0.96	53,800

[a] EPA assumes a 10-year life, and a 7% discount rate
[b] The total annualized cost includes capital, labor and electrical power
[c] Includes both labor and operational costs such as electrical power (unlike EPA costs above in same column)
[d] Range between calculated value and reported value

[632] *Lessons Learned from Natural Gas STAR Partners – Convert Gas Pneumatic Controls to Instrument Air,* 2006, attached hereto as Exhibit 208.

In its NSPS TSD,[633] EPA estimates that the capital cost of conversion to instrument air pneumatics, depending on the size, ranges from about $17,000 to $135,000 per controller, along with sizeable yearly maintenance and operational costs. The natural gas savings increase with the size of the pneumatic controller. However, according to the TSD, the savings are not enough to recover the cost of operating and maintaining the devices. As a result, for all device sizes, the devices have a negative annualized profit (which includes the annualized capital cost). Accordingly, EPA states that the investments do not pay back.

This is in contrast to EPA's 2005 assessment based on Natural Gas STAR program experience.[628, 629] There, the average cost of installing an instrument air device was $10,000 with an average $7,500 expenditure in annual maintenance and operations per controller. The average total cost estimate was even smaller than EPA TSD's small-scale device estimates. Also, in proportion to the investment cost, the 2005 EPA estimate of the natural gas savings was much larger in magnitude. Consequently, this rendered instrument air implementation profitable and the investment paid itself back in less than two years.

Similarly, EPA's estimates are in contrast to EPA's Natural Gas STAR Lessons Learned from 2006.[634] In that report, the capital and installation cost of the device was larger at $60,000 per controller. But the natural gas savings were commensurately larger to render the investment profitable with a payback period of about one year. We further note that the EPA TSD based its estimates on the 2006 Lessons Learned document (above). While the cost of implementation estimates are consistent between the two sources, the EPA TSD's revenue estimates are much lower than those in the Lessons Learned document. For instance, the Lessons Learned document estimates average natural gas savings of about 23,000 Mcf/year for medium-sized controllers and about 20,000 Mcf/year on average. In contrast the EPA TSD estimates for medium-sized controllers are 5-6 times lower. The reason for this has not been made sufficiently clear, and EPA must clarify its rationale.

In sum, our analysis shows that the EPA TSD's cost estimates for instrument air pneumatic controllers may have been somewhat overestimated. Also, it is unclear why the EPA TSD's revenue estimates are lower than in other reports. EPA must provide further clarification in both these regards. In the absence of such explanation, we consider the overall economic estimates made in the EPA TSD to be potentially conservative.

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[633] EPA NSPS TSD, pages 5-19 – 5-22

[634] *Lessons Learned from Natural Gas STAR Partners – Convert Gas Pneumatic Controls to Instrument Air*, 2006. attached hereto as Exhibit 209.

d. Reciprocating compressors

We assess EPA's estimated cost of control and cost-effectiveness of replacing worn rod packing in reciprocating compressors to be potentially conservative. EPA's proposal is better supported than the agency acknowledges.

Table 7: Cost of control analysis of replacing rod packing in reciprocating compressors

			#	$	$ / yr	Mcf	$ / Mcf	$	$ / yr	Years	$ / yr
Source	**Year**	**Type**	**# devices**	**Total cost per packing**	**Annualized cost of packing**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA – NSPS TSD [635]	2008	Production	1	6,480	2,493	9[a]	4	36	36	180.00	(2,457)
EPA – NSPS TSD	2008	Gathering, Boosting	1	5,346	1,669	396[a]	4	1,584	1,584	3.38	(85)
EPA – NSPS TSD	2008	Processing	1	4,050	1,413	1,077[a]	4	4,308	4,308	0.94	2,895
EPA – NSPS TSD	2008	Transmission	1	5,346	1,669	1,257[a]	-	-	-	NA	(1,669)
EPA – NSPS TSD	2008	Storage	1	7,290	2,276	1,263[a]	-	-	-	NA	(2,276)
EPA – NSPS TSD	2008	Simple average	1	5,702	1,904	296	4	1,186	1,186	4.81	(718)
JPT	2008	Average	1	4,800[b]	1,847[c]	3,504[d]	4	14,016	14,016	0.34	12,169
EPA Lessons Learned Error! Bookmark not defined.	2006	Average	1	6,480[e]	2,493[c]	3,460	4	13,840	13,840	0.47	11,347

[a] EPA NSPS TSD, page 6-15, Table 6-6; based on individual compressor emissions reductions in tons per year

[b] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,200 per cylinder

[c] Using same capital recovery factor as used in the EPA TSD for reciprocating compressors in the production sector (EPA TSD Table 6-2)

[d] Multiplying estimated emissions savings as reported by sources by 4, to account for savings from 4 cylinders

[e] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,620 per cylinder

In its NSPS TSD,[635] EPA estimates that replacing rod packing costs between $4,000 and a little over $7,000 per rod packing replacement. The natural gas savings depends on which stage of the natural gas system the device operates. According to the TSD, the most profitable device is in the processing stage where it has an annualized profit (which includes the annualized capital cost) of about $2,900 per compressor and a payback of 1 year. EPA also found in the TSD that some of the less profitable devices are not profitable enough to pay back even the initial investment.

In our two references, the cost of replacing the rod packing is largely consistent with EPA TSD's estimates. We note that one of the references[636], the EPA Natural Gas STAR Lessons Learned 2006 document, is the same as the one that the EPA TSD states that it obtained its cost estimates from. The other reference[637] notes a slightly lower cost for replacing rod packing.

However, when it comes to annual natural gas revenues from sales, the EPA TSD's estimates indicate that there are almost negligible revenue from the production sector (less than $50), about $1,500 of revenue from the gathering and boosting sectors, about $4,300 of revenue from the processing sector. The rationale for this variation, amongst what appear to be similarly-sized compressors, is not entirely elucidated by EPA. The variation is counter to average industry estimates reported in our references (one of which is even used by the EPA TSD), which do not identify different natural gas revenues in different sectors. Importantly, the natural gas revenues reported in our references is significantly larger than those in the EPA TSD.

As a result, our estimates indicate that replacing rod packing systems in all the three sectors mentioned above would be profitable and have a reasonable cost of control. We note that even the EPA TSD's most profitable compressor (in the processing sector) is much less profitable than our estimates.

In sum, our analysis shows that the EPA TSD's estimates for the cost of replacing rod packing systems are consistent with ours. We request the EPA to further explain why the natural gas revenue estimates are so different in the different sectors and lower on the whole than other references, and to revise its figures appropriately. In the absence of this explanation we consider the overall economic estimates made in the EPA TSD to be potentially conservative.

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[635] EPA NSPS TSD, pages 6-15 – 6-18.

[636] *Lessons Learned from Natural Gas STAR Partners – Reducing Methane Emissions from Compressor Rod Packing Systems*, 2006.

[637] Journal of Petroleum Technology, *Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*, June 2005.

e. Compressors with dry seals

We assess EPA's estimated cost-effectiveness of replacing wet seals in centrifugal compressors with dry seals to be conservative. EPA's proposal is better supported than the agency acknowledges.

Table 8: Cost of control analysis of replacing wet seals in centrifugal compressors with dry seals

			#	*$*	*$ / yr*	*Mcf*	*$/Mcf*	*$*	*$/year*	*$ /yr*	*Years*	*$ /yr*
Source	**Year**	**Type**	**# devices**	**Total cost per device**	**Annual. cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Maint., operational savings per year**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA – NSPS TSD [638]	2008	Processing	1	75,000[a]	10,678[b]	11,527[c]	4	46,108	88,300	134,408	0.56	123,730
EPA – NSPS TSD	2008	Trans. / Storage	1	75,000	10,678	6,372[c]	-	-	88,300	88,300	0.85	77,622
EPA – NSPS TSD	2008	Simple average	1	75,000	10,678	8,949		23,054	88,300	111,354	0.67	100,676
EPA NG STAR [639,640]	2009	Average	1	162,000[d]	23,064[e]	50,000	4	200,000[f]	120,000[g]	320,000	0.51	296,936
Petroleos Mexicanos [641]	2008	Average	1			35,000	4	140,000	??	140,000+	??	126,690
Targa [642]	2006	Average	1	90,000	12,814			??	??	300,000	0.38[h]	287,186

[a] EPA reports this to be 1-3% of the total pipeline cost
[b] EPA assumes a 10-year life and a 7% discount rate
[c] EPA NSPS TSD, page 6-20, Table 6-8; based on individual compressor emissions reductions in tons per year
[d] Assumes half the value of a retrofit
[e] For annualized capital cost, assumes similar lifetimes and discount rate as in EPA's estimates
[f] Conservative low estimate of natural gas savings based on the range of savings from $75,000 - $400,000
[g] Average maintenance and operational savings of $120,000 based on the range of savings of $100,000 - $140,000
[h] Average of 2 – 7 months

In its NSPS TSD,[638] EPA estimates the incremental capital cost of newly installing centrifugal compressors with dry seals instead of centrifugal compressors with wet seals at $75,000 on average. This is the cost of installing a new dry seal compressor instead of a new wet seal compressor. EPA further assumes annual operational savings of $88,300 and additional annual natural gas revenue of approximately $46,000 per compressor from compressors in the processing stage, but no additional revenue in the transmission / storage stage. This is equivalent on average (simple average) to an annualized profit (which includes annualized capital costs) of about $100,000 and a payback period of about 8 months (0.67 years) per new compressor with dry seals instead of wet seals.

According to EPA Natural Gas STAR 2009 reports,[639] a dry seal retrofit (generally more expensive than a new installation) costs $324,000 per compressor on average, with annual operational savings of $100,000 - $140,000 and additional revenues of ranging from $75,000 to $420,000[640] per compressor. A conservative average annual revenue from natural gas of $200,000 per compressor was assumed here. Operational savings are expected from reduced downtime due to less required maintenance, improved compressor reliability, reduced power requirements and elimination of seal oil costs. The average operational savings and additional revenue are noted to be higher than EPA's NSPS TSD estimates. Furthermore, conservatively assuming that the incremental capital cost of a dry seal compressor versus a wet seal compressor is as much as half the cost of a retrofit, the payback period for a dry seal investment instead of wet seal is just over half a year.

In 2008, Petróleos Mexicanos (PEMEX) assessed the benefits of converting from wet seals to dry seals on centrifugal compressors at a compression station in southern Mexico. It found gas savings of 33.5 scfm per seal, and gas savings of 35 MMcf/year, resulting in a profit of $126,690 per year.[641]

Targa Resources and the Gas Processors Association report that replacing a wet seal with a dry seal on a six-inch shaft beam compressor that operates approximately 8,000 hours per year, leaking at 40 - 200 scfm, will pay back in 4 to 15 months, yielding more than $1 million in NPV, assuming a 10 percent discount rate in a span of five years, and

[638] EPA NSPS TSD, pages 6-19 – 6-22.
[639] EPA Natural Gas STAR, *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*, EPA 430-B-03-012, 2009.
[640] EPA 2011 GHG inventory leak rates: emission estimates used a leak rate of 2125 scfh, (18,600 Mscf/year) equivalent to approximately $75,000 of gas leaking from each compressor each year it is not repaired. EPA estimates that some wet seal compressor leaks can be as high as 200 scfm (105,000); approximately $420,000 of gas leaking from each compressor each year it is not repaired. This assumes a natural gas price of $4/Mcf.
[641] Methane to Markets, Natural Gas STAR International, *Reducing Emissions, Increasing Efficiency, Maximizing Profits*, epa.gov/gasstar/international/index.html, 2008, attached hereto as Exhibit 210.

more than a 170 percent rate of return.[642] The payback period here is for a retrofit. Again, conservatively assuming that an incremental investment in a dry seal compressor is as much as half the cost of a retrofit, the payback period may be expected to halve to 2 – 7 months.

In sum, we consider EPA to have underestimated the average operational savings and the emissions reductions (and so additional natural gas revenue) from the average investment analyzed, leading to conservative cost-effectiveness, profitability, and payback estimates..

f. Tank Vapor Recovery Units

We assess EPA's estimated cost of control and cost-effectiveness of installing tank vapor recovery units to be overly conservative. EPA's proposal is better supported than the agency acknowledges.

[642] Targa Resources and the Gas Processors Association, Methane Savings from Compressors and VRUs, Innovative Technologies for the Oil & Gas Industry: Product Capture, Process Optimization, and Pollution Prevention, July 27, 2006

Table 9: Cost of control analysis of installing vapor recovery units

				$	$ / yr	$ / yr	$ / yr	Mcf	$/Mcf	$	$ / yr	Years	$ / yr	$ / yr
Source	**Year**	**Type**	**# dev.**	**Total capital cost per device**	**Annual. capital cost of device**	**Maint., oper. costs per year**	**Annual. total cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Oper. profit per year**	**Annual. profit per year**
EPA [643]	2008	Average	1	98,186	10,780 [a]	9,367	20,147	291	4	1,164	1,164	negative	(8,203)	(18,983)
EPA NG STAR [644]	2010	Small scale	1	35,738 [b]	3,924 [c]	7,367	11,291	4,566	4	18,262 [d]	18,262	3.28	10,895	6,972
EPA NG STAR	2010	Medium scale	1	55,524	6,096	10,103	16,199	18,262	4	73,048	73,048	0.88	62,945	56,849
EPA NG STAR	2010	Large scale	1	103,959	11,414	16,839	28,253	91,311	4	365,242	365,242	0.30	348,403	336,990
EPA NG STAR	2010	Simple average	1	65,074	7,145	11,436	18,581	38,046	4	152,184	152,184	0.46	140,748	133,603
Anadarko [644]	1999	Average	300										4,167	
ConocoPhillips [644]	??	Average	9	79,167	8,692 [c]							0.33	252,000	243,308
Chevron [646]	1996	Average	8									<1		

[a] EPA assumes a 15-year life and a 7% discount rate

[b] This includes capital cost and installation cost equal to 75% of the capital cost

[c] For annualized capital cost, assumes similar lifetimes and discount rate as in EPA's estimates
[d] Scaled down from savings based on a historically higher natural gas price of $6.22/Mcf

In its NSPS TSD,[643] EPA estimates the capital costs of installing a vapor recovery unit on storage vessels at $98,186, with an additional $9,367 in annual operational and maintenance expenses. According to the TSD, the additional revenue from captured natural gas is $1,164 per vapor recovery unit per year, leading to an annualized loss of $18,893 per unit. Also, due to an annual operating loss on the vapor recovery unit (i.e., operational and maintenance expenses exceed additional natural gas revenue), the TSD concludes that the investment does not pay itself back.

Yet, according to EPA's 2010 report on earnings from Natural Gas STAR programs,[644] vapor recovery projects of various sizes can be profitable with payback periods ranging from a few months to about three years. Natural gas savings were calculated based on a price of $6.22/Mcf; accordingly savings reported here have been scaled down for a natural gas price of $4/Mcf. Even so, we note that even the least-profitable small-scale vapor recovery units generated more revenue from natural gas savings than associated operational and maintenance costs, to yield a net annual operating profit and a consequent investment payback of 3.28 years. Larger tank vapor recovery units had much stronger profitability, with the largest units paying back in 3 - 4 months.

Additional examples of tank vapor recovery profitability include:

- Anadarko reported netting $7 million to $8 million between 1993 and 1999 by installing more than 300 vapor recovery units.[644]
- ConocoPhillips installed vapor recovery on nine tank batteries at a total cost of $712,500. The company's investment paid back within 4 months, earning $189,000 per month thereafter.[645]
- Chevron installed eight vapor recovery units on crude oil stock tanks in 1996; this investment paid back in less than one year.[646]

In sum, we consider EPA's estimates of the cost-effectiveness and profitability of vapor recovery units to be very conservative. In our assessment this is primarily due to the TSD's exceedingly low estimates of natural gas savings from vapor recovery units, which are at least 25 times lower than other reports of vapor recovery units in operation. As we discuss below, these savings are properly considered in the BSER analysis.

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[643] TSD at 7-13 – 7-14.

[644] EPA Natural Gas STAR, *Reducing Methane Emissions with Vapor Recovery on Storage Tanks, Lessons learned from the Natural Gas STAR Program*, Newfield Exploration Company, Anadarko Petroleum Corporation, Utah Petroleum Association, Interstate O&G Compact Commission, Independent Petroleum Association of Mountain States, March 23, 2010, attached hereto as Exhibit 211.

[645] *Id.*

[646] Richards, L.S., Hy-Bon Engineering, Co., *Fundamentals of Vapor Recovery, Associated Gas is Lost Product and Lost Revenue*, October 2005, attached hereto as Exhibit 212.

g. Leak Detection and Repair

We assess EPA's estimated cost of control, cost-effectiveness and profitability of conducting leak detection and repair to be potentially conservative. EPA's proposal is better supported than the agency acknowledges.

Table 10: Cost-effectiveness of leak detection and repair systems

				$	*$/year*	*$ / year*	*Mcf*	*$/Mcf*	*$*	*$ /yr*	*Years*	*$ /yr*
Source	**Year**	**Type**	**# devices**	**Total capital cost per device**	**Maint. oper. per year**	**Annual. total cost of device**	**Vol. of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA - NSPS TSD [649]	2008	Valves	1	18,529 [a]	incl. in total	34,608	1,060 [a]	4	4,241	4,241	negative	(30,366)
EPA - NSPS TSD	2008	Connectors	1	9,991	incl. in total	25,622	515	4	2,061	2,061	negative	(23,561)
EPA - NSPS TSD	2008	Pressure Relief Devices	1	101,820	incl. in total	40,372	160	4	639	639	negative	(39,734)
EPA - NSPS TSD	2008	Open ended lines	1	12,280	incl. in total	26,200	693	4	2,772	2,772	negative	(23,428)
EPA - NSPS TSD	2008	Simple average	1	35,655	incl. in total	31,700	607	4	2,428	2,428	negative	(29,272)
EPA Lessons Learned[647]	2003	Gas processing plants	1	59,000 [b]	32,000 [c]	91,000	86,500 [d]	4	346,000	346,000	0.19	255,000
EPA Lessons Learned[648]	2003	Compressor stations	1	26,200		26,200	29,400	4	117,600	117,600	0.22	91,400
Methane to Markets	2009	Valves	1	130	??	??	2,895	4	11,580	11,580	likely +ve	likely +ve

[647] Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations, 2003
[648] Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Compressor Stations, 2003

Methane to Markets	2009	Connectors	1	10	??	??	3,482	4	13,928	13,928	likely +ve	likely +ve
Methane to Markets	2009	Open ended lines	1	60	??	??	2,320	4	9,280	9,280	likely +ve	likely +ve
Methane to Markets	2009	Simple average	1	67			2,899	4	11,596	11,596	likely +ve	likely +ve
Canadian experience	2005	Average	??								+ve	+ve

[a] Average of values from Tables 8-14, 8-15 and 8-17. Table 8-16 data was not included as that was only incremental cost data

[b] Average of $39,000 and $78,000 for repairs annually

[c] Average of $14,000 and $50,000 for leak screening and measurement annually

[d] Average of 45,000 and 128,000 Mcf/year per gas plant

In its NSPS TSD,[649] EPA included comprehensive calculations for the capital and operational cost of conducting leak detection and repair at existing gas processing plants. EPA reports that the annualized cost (including capital) for detecting and repairing leaks, by component, is between $20,000 and $40,000 on average. The savings of natural gas from these repairs is on the order of $1,000 - $4,000. As a result, EPA estimates that leak detection and repair incurs an annual operating loss and accordingly the investments do not pay back.

This is in sharp contrast with EPA Lessons Learned documents for both gas processing plants[650] and compressor stations.[651] In these examples, cost of repairs were between $25,000 and $60,000 per year per facility. For gas processing plants, leak screening and monitoring cost about $32,000 annually per plant. At both gas processing plants and compressor stations, the investments were profitable generating as much as $250,000 in annualized profit per facility, with payback periods of just a few months.

The NSPS TSD estimates are also very different from a 2009 Methane to Markets presentation showing that leak repair can be highly profitable.[652] Given the large differences between EPA and the Methane to Markets capital cost data, it is likely that the cost estimates are not like-for-like. For example, the latter did not include operational and labor costs, and it may have excluded broader system costs. The Methane to Markets presentation also estimates much larger average natural gas savings from discrete repairs, however, which would make detection and repair much more profitable than EPA predicts even when the additional costs are considered.

Additionally, Canadian experience with control of fugitive emissions at oil and gas facilities shows that: most methane leaks are from components in gas service; older facilities have the highest leak rates; about 75 to 85 percent of leaks are economic to repair; and the top 10 leaks at a facility generally contribute more than 80 percent of the emissions.[653]

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[649] EPA NSPS TSD, pages 8-23 – 8-30, mainly Tables 8-14 – 8-17.

[650] *Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations*, 2003, attached hereto as Exhibit 213.

[651] *Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Compressor Stations*, 2003, attached hereto as Exhibit 214.

[652] Methane to Markets, *Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M)*, Oil & Gas Subcommittee Technology Transfer Workshop, 2009, attached hereto as Exhibit 215. The Methane to Markets Partnership was a collaborative effort among 14 countries to address issues surrounding climate change, methane, and clean energy; the Global Methane initiative, formed by 37 governments and the European Commission in October 2010, builds on the Partnership's work.

[653] Picard, D. (Clearstone Engineering Ltd.), *Cost Effective Opportunities to Reduce Methane Emissions and Losses,* 2005, attached hereto as Exhibit 216.

3. Qualitative considerations of the costs of control technologies

As is apparent from the quantitative analysis presented above, EPA's cost estimates for many of the control technologies are conservative by our assessment, and so underestimate the reasonableness of the cost of control EPA's proposal would require.

We anticipate that some industry commenters may nonetheless contend that these costs must be higher than EPA, or we, have calculated, since those calculations show that some of these measures *save operators money,* yet they have not been universally adopted by operators.

Industry's failure to voluntarily adopt all of EPA's proposed controls does not indicate that the cost of control is not reasonable, or that the control in question is not correctly included as BSER. As explained by the American Petroleum Institute (API), these projects would need to meet internal hurdle rates and compete with core business projects for available capital.[654] Thus, companies may forego even profitable projects in favor of, for instance, new well construction, in the absence of federal regulation requiring them to take action.

For example, if a company has a hurdle rate of 30 percent for making investments, then the control technology would need to be quite profitable to meet this threshold. But this is not the standard for BSER purposes: instead, EPA is only to consider whether costs are truly exorbitant on an industry-wide basis. Therefore, there would be a very large number of projects, even within the Natural Gas STAR partner-companies, that would pose reasonable costs – indeed, in some cases, negative costs -- even while not meeting the likely high hurdle rates for voluntary implementation.

Market failures, in particular "principal agent" problems, can also prevent an industry from undertaking cost-effective measures. Structures of firms may not incentivize managers to undertake measures. Managers may also be quite excessively risk-averse, or simply excessively resistant to new technologies. Finally, managers may lack the necessary information to undertake cost-effective measures.

Moreover, the opinion of experts within the natural gas industry[655] demonstrates that a large number of natural gas companies, especially small to midsize ones, have yet to

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[654] American Petroleum Institute (API), and the International Petroleum Industry Environmental Conservation Association (IPIECA), *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, prepared by URS Corporation, March 2007, attached hereto as Exhibit 217, concludes at p. 18 "*Companies and investors operate under capital constrains and the estimated financial returns of such GHG reduction projects may not justify diverting capital from other higher return or more strategic initiatives.*"

[655] Public discussions in June 2011 convened by the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board on natural gas operations, with C-level executives from Chesapeake, Schlumberger, Anadarko, Chevron, ExxonMobil etc.; independent natural gas industry consultants.

update their outmoded practices and embrace a culture of efficiency and corporate responsibility. We therefore consider that significant opportunity to reduce methane emissions exists, especially from small to midsize operations.

Furthermore, the Natural Gas STAR program has about 130 partner companies,[656] with the number of companies in the various stages of natural gas operations being approximately: 30 in production; 10-15 in processing; 35 in transmission; and 55 in distribution. But the number of companies in the US in the various stages of natural gas operations far exceeds this number and is approximately: 6000 in production, 120 in processing; 250 in transmission and storage; 1200 in distribution (and 260 in marketing).[657] While there may be numerous overlaps due to companies operating in multiple stages, even if the total number of unique companies was only 1,500, this figure would still be more than ten times the number of companies participating in Natural Gas STAR. In other words, the number of Natural Gas STAR partner companies is lower than even 10% of the total number of companies. While some number of the remaining 90+% of companies may be smaller operators, they nonetheless would represent a sizeable fraction of natural gas operations. It is quite likely that these companies have not engaged significantly in VOC/methane control activities. As such, we consider that there may be a number of VOC/methane control opportunities, ranging from merely reasonable cost to highly profitable, that remain untapped.

Finally, the general phenomenon of regulation leading to increased productivity within affected firms has been observed in various sectors[658] and is consistent with economic theory.[659]

C. EPA Underestimated Savings Due to Natural Gas Capture Under its Proposal

As noted above, in addition to analyzing costs of implementing the technologies and any operational savings, EPA assessed the additional revenue from natural gas that was not emitted. Regulated entities will directly benefit from this additional revenue, as it will offset the cost of installing controls. As such, these benefits plainly affect "the cost of achieving such reduction" of emissions,[660] and so can and must be included in EPA's cost of control analysis.

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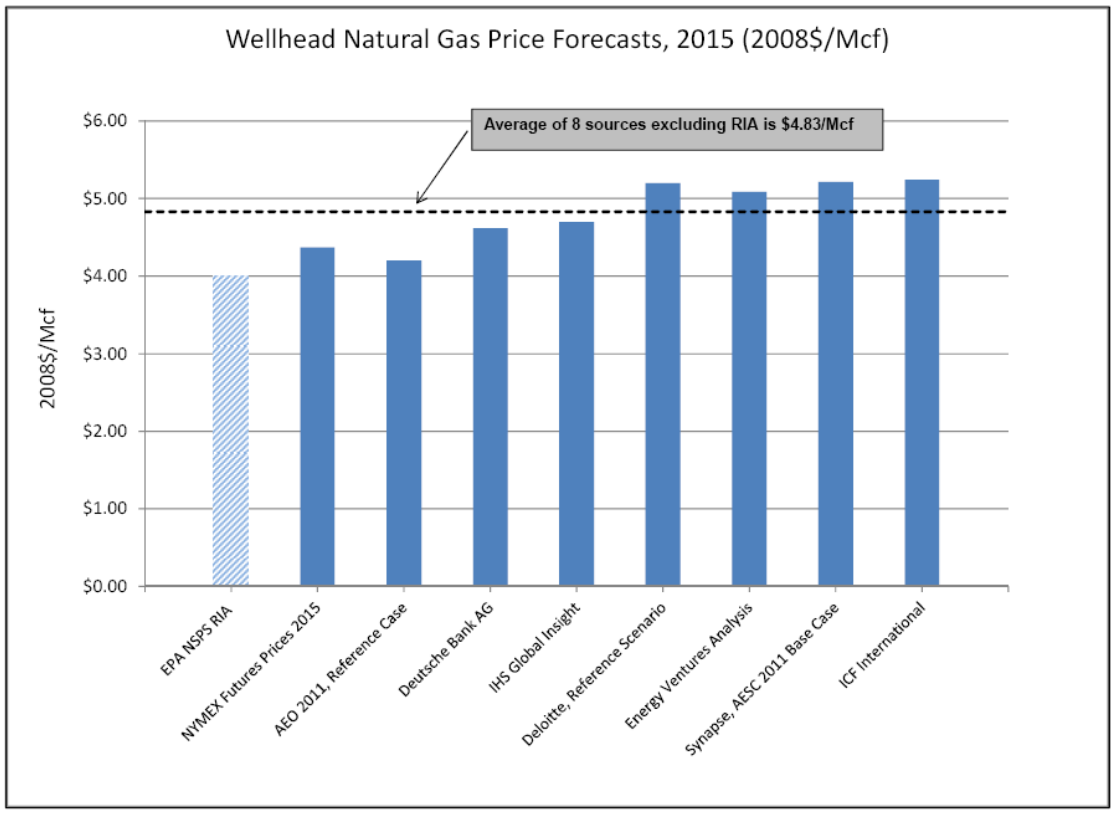
[656] EPA Natural Gas STAR: http://www.epa.gov/gasstar/documents/partnerlist.pdf
[657] http://www.naturalgas.org/business/industry.asp#industry; http://www.gpaglobal.org/membership/companies/
[658] Porter, M.E. (1990), *The Competitive Advantage of Nations*, Free Press, New York.
[659] Mohr, R.D. (2002), "Technical Change, External Economies, and the Porter Hypothesis," *J. Environ. Econ. Manag.,* 43, 158-168, doi:10.1006/jeem.2000.1166; Ambec, S., and P. Barla (2002), "A theoretical foundation of the Porter hypothesis," *Econ. Lett*., 75 (2002) 355–360, attached hereto as Exhibit 218.
[660] 42 U.S.C. § 7411(a)(1).

EPA assumed a $4/Mcf price for natural gas in its revenue calculations. EPA used these calculations in both the RIA and in its BSER determinations themselves.[661] EPA's price assumption is lower than all other projections, including the Energy Information Administration's. EPA must update its calculations to reflect a realistic gas price, using the Energy Information Administration and offering sensitivity analyses for other prices.

According to projections by Synapse Energy Economics submitted as an attachment to these comments, $4/Mcf is a low estimate for future natural gas prices, although it is above current prices. Indeed, this price is lower than $4.22/Mcf price forecast by the Energy Information Administration (EIA). As it turns out, it is lower than *every* other credible natural gas price projection.[662] Synapse concluded that the future price of natural gas was projected to be around $4.8/Mcf in 2015. Notably, prices beyond 2015 are projected to be even higher. Figure 7 below, drawn from that report, shows that some estimates exceed $5/Mcf, and *all* estimates are above EPA's.

Figure 7



[661] *See, e.g.*, 76 Fed. Reg. at 52,758 (taking cost savings from natural gas capture into account in proposing green completions as BSER).

[662] Synapse used data from eight different sources to conduct its analyses, including from the Energy Information Administration, Deutsche Bank, Deloitte, ICF International and NYMEX.

If EPA used even the EIA projection, it would "double the estimate of net cost savings of the proposed NSPS," going from $45 million to $90 million in savings.[663] If EPA were to use the mean value of all of the above cost estimates, $4.84 Mcf, it would estimate net cost savings of $180 million.[664]

The costs of implementing VOC/methane control technologies are very unlikely to rise as much as 20 percent (which is the relative difference between $4.8/Mcf and $4/Mcf) by 2015. Therefore, based on the higher projected price of natural gas, the economics of the methane control opportunities would become far more favorable. Moreover, the higher natural gas prices rise – recent volatility has seen prices go as high as about $8/Mcf – the more profitable methane control options become.

Recognizing that all forecasts are somewhat subjective, it is clear that EPA's forecast – and its projected cost savings – are systematically low. EPA must, therefore, use the EIA value, at a minimum, and include higher possible wellhead values, as it estimates the savings from the rule to supports its standards-setting analysis. Failure to do so masks the real, and extraordinary, benefits of EPA's proposal.

D. EPA Must Include the Quantified Social Benefits of Methane Reduction, in Addition to Non-Climate related Health Benefits Resulting from Methane Reduction.

According to EPA, the proposed rules, if finalized, would reduce methane emissions by 3.4 million tons per year, resulting in a net annual reduction in total greenhouse gases of approximately 62 million metric tons of CO_2 equivalent (CO_2e).[665] This is a substantial emissions reduction: It is larger than the *total* CO_2e emissions of several industry sectors, and will produce correspondingly large benefits by reducing the powerful climate influence of methane.[666] Although the benefits of this reduction do not speak to the direct cost of the controls required by EPA's proposed standards, and hence are not part of the BSER analysis, they are vitally important to the larger cost/benefit analysis EPA offers in the RIA for the rule. EPA must value them accurately.

EPA tentatively offers quantified co-benefits of between $110 to $1,400 per short ton of methane reduced (depending on discount rate) – for a total of $373 million to more than $4.7 billion[667] - but citing "the uncertainty involved" in the methods it uses,

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[663] RIA at 3-19.
[664] Rick Hornby and Dr. Carl Swanson, Synapse Energy Economics, *Estimate of 2015 Natural Gas Wellhead Prices* at 3, attached hereto as Exhibit 220.
[665] 76 Fed. Reg. at 52,792.
[666] *See, e.g.*, EPA, Inventory of U.S. Greenhouse Gases and Sinks (1990-2009), April 2011 at Table ES-2 (noting, for instance, that the total emissions from iron and steel production in 2009 was just 41.9 million metric tons of CO_2).
[667] RIA at 4-32.

"chooses not to compare these co-benefit estimates to the costs of the rule for this proposal."[668]

This is a substantial omission, as it fails to account adequately for one of the most significant benefits of the rule. EPA must not wait to have "interagency accepted monetary values" for the social benefits from methane reduction,[669] before including monetized benefit figures in its RIA. Indeed, E.O. 12866 calls upon the agency to include "quantifiable measures (to the fullest extent that these can be usefully estimated),";[670] E.O. 13563 likewise directs EPA to use the "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible."[671] Neither of these sources permits EPA to wait for interagency agreement before assessing monetized costs.

Because EPA currently has two supportable quantification methods available – direct assessment of the social cost of methane ("social cost of methane method" or "SCM method") and using methane's GWP to calculate CO_2e, then multiplying by the social cost of carbon ("GWP method") – it must use these tools to report a range of monetized benefits for the rule.

As the Ninth Circuit Court of Appeals explained in *Center for Biological Diversity v. NHTSA*, some uncertainty in estimation methodologies does not support declining to quantitatively value benefits associated with reducing climate change pollution at all.[672] Where, as here, "the record shows that there is a range of values [for these benefits], the value of carbon emissions reduction is certainly not zero."[673] Therefore, the agency is obligated to consider such a value, or range of values.[674] Since the agency has a strong quantitative foundation now in the form of two methodologies for estimating the social cost of methane, it should provide monetized benefits using both of these methodologies in its formal cost-benefit assessment (accompanied by an explanation of any limitations and/or uncertainties in each methodology, as necessary).

Finally, EPA must also consider the *non-climate related* health and public welfare benefits of methane reductions. These arise because methane is a significant precursor of surface-level ozone, which causes significant morbidity and mortality and damages crops.

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[668] 76 Fed. Reg. at 52,792-93.
[669] *See* RIA at 4-32
[670] 58 Fed. Reg ____ (October 4, 1993)
[671] (76 Fed. Reg. at 3821 (January 21, 2011)
[672] *See Center for Biological Diversity,* 538 F.3d 1172, 1200 (9th Cir. 2008) (citing Office of Management and Budget Circular A-4 as providing that "agencies are to monetize costs and benefits whenever possible."), attached hereto as Exhibit 221.
[673] *See id*
[674] *See id.* at 1203.

1. EPA has two available methods for monetizing climate benefits from methane reduction.

The Social Cost of Methane Method ("SCM Method"). In Marten and Newbold,[675] the authors directly calculate the social cost of methane using the methodology used by the Interagency Working Group on the Social Cost of Carbon, with some updates. This direct method would be the most straightforward, defensible, and consistent with earlier valuation efforts of greenhouse gases.[676] EPA provides no reason why it cannot do the same here. The agency rejects earlier analyses of the direct social cost of methane, dated from 1994 to 2006, on the basis that "[t]he assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the [integrated assessment models]."[677] However, EPA only cites Marten and Newbold as supporting why the GWP method explored in the RIA may be viewed as a yielding a lower bound for quantified methane benefits,[678] not any reason why EPA cannot use the SCM method. As Marten and Newbold's method is a valid and analytically supportable method, EPA must include figures calculated using their social cost of methane approach.

The GWP Method. The GWP Method consists of converting the methane emission reductions to CO_2-equivalent using methane's global warming potential, then multiplying the resulting CO_2e figure by the social cost of carbon ("SCC"). As noted by Marten and Newbold, this approximation of the climate benefits of methane reductions underestimates benefits at the higher discount rates considered by the interagency SCC group; in one case the underestimate is in excess of 30%.[679] They further note, however, that values of the benefit of methane reductions "estimated using GWPs and the [SCC] will typically have lower absolute errors than default estimates of zero."[680] In other words, using GWP and the SCC to calculate the value of methane emissions reductions is more accurate than not calculating the value of methane reductions, and implying that the value is zero, as EPA has done by failing to compare any value of

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[675] Marten, A. L., and Newbold, S. C. (2011), "Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide," EPA NCEE Working Paper # 11-01, available at http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01, attached hereto as Exhibit 222.

[676] We note that not all damages from climate warming (or non-climate damages from methane) are accounted for in any calculation of the SCM because they are not included in the underlying models. However, that the models may pose some uncertainties due to their incompleteness does not mean that EPA can refuse to use them. *See Center for Biological Diversity*, 538 F.3d at 1201-02 (rejecting NHTSA's claim that it did not have to monetize benefits because the models were too uncertain). In addition, the Johnson Report provides comments on how to remedy some of these shortcomings.

[677] RIA at 4-33.

[678] *See id.* at 4-32 (Marten and Newbold "suggest" that the "'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases")

[679] *Id.* at 16. These underestimates can be seen by comparing the SCM, as calculated by Marten and Newbold, with the product of the SCC as they calculated it and a GWP.

[680] Marten and Newbold at 1.

reduced methane emission to the cost of mitigation measures. If EPA is unable to include a directly-calculated SCM in support of the final rule due to methodological problems with the SCM, it must (after identifying and explaining those problems) instead include an estimate of methane-related climate benefits calculated by multiplying SCC by GWP (with an updated GWP as described below).

We note that the flaws and uncertainties in these methods spring from their under-estimation of the true costs of climate change damages, as well as the inherent limitations of attempting to monetize impacts such as human suffering, loss of life, and loss of non-human species. [681] Thus, while they must be considered by definition under-estimates of the true social cost of greenhouse gases, this does not allow the EPA to ignore the existing values entirely, thereby further under-stating the benefits of greenhouse gas reductions.

2. EPA must adjust certain assumptions in the GWP method and the underlying SCC method.

We also attach a detailed discussion by NRDC chief economist Dr. Laurie Johnson of needed adjustments in the GWP method, if EPA uses this approach, as well as in the underlying SCC, regardless of whether EPA includes estimates using the SCM or GWP method (as both the SCM and GWP approaches rely on the methodology of the SCC). This analysis, which we incorporate by reference into these comments, yields several important additional recommendations for EPA's analysis[682]:

First, EPA must use the most recent Intergovernmental Panel on Climate Change (IPCC) GWP values for methane. EPA uses the lower GWP value from the years-old IPCC Second Assessment Report, rather than from the more recent Fourth Assessment Report, because values from the Second Assessment are used in "global GHG inventories" (*i.e.,* produced under the guidelines of the United Nations Framework Convention on Climate Change).[683] Those inventories are not relevant to EPA's goal here, which is to accurately estimate methane benefits, not to report to a "global GHG inventor[y]." That these inventories still use inaccurate conversion values is simply not a justification to undercount methane benefits here.

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[681] See, e.g., Ackerman, F, and E. Stanton. 2010. *The Social Cost of Carbon. A Report for the Economics for Equity and the Environment Network*. Available at http://www.e3network.org/papers/SocialCostOfCarbon_SEI_20100401.pdf, attached hereto as Exhibit 223; Ackerman, F. Cost-Benefit Analysis of Climate Change: Where it Goes Wrong, pp.61-81 in Economic Thought and U.S. Climate Change Policy (David. M. Driesen, ed.) MIT Press, 2010.
[682] These recommendations are drawn from pp. 3-4 of Dr. Johnson's report.
[683] 76 Fed. Reg. at 52,793.

Second, even the most recent IPCC GWP from the Fourth Assessment may somewhat undervalue methane's strength as a climate forcer. EPA must, at least, include a sensitivity analysis using the more recent estimate from Shindell et al. of 33.[684]

Third, EPA must provide range of benefits yielded from the various methods and assumptions (c.f. table 1 in Marten and Newbold), as well as a clear, tabular, demonstration of how it has calculated the monetized benefits.

Fourth, as the larger Interagency Working Group on the Social Cost of Carbon continues to improve its calculations, EPA must be sure that these improvements are captured in its analysis here (if they occur during the rulemaking).

3. EPA must also Take Non-Climate Benefits of Reducing Methane Emissions Into Account

Although EPA does not regulate methane as a VOC precursor of ozone,[685] methane is a hydrocarbon which chemically oxidizes in the atmosphere to drive ozone production. While this oxidation is too slow for regional methane controls to substantially reduce ozone levels in that same region, anthropogenic methane contributes significantly to background levels of ground-level ozone around the world. Numerous modeling studies have predicted that reducing methane emissions can significantly reduce surface ozone.[686]

For example, West *et al.* (2006) report that reducing global anthropogenic methane emissions by about 20% would reduce the global average daily 8-hr ozone maximum by over 1 part per billion by volume (ppbv), "in agreement with other models [from other research groups]."[687] The reduction of ozone resulting from methane emissions abatement may be greater in densely populated urban areas, where other pollutants

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[684] D.T. Shindell, G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, S.E. Bauer (2009) "Improved Attribution of Climate Forcing to Emissions," *Science* 326 716-718, attached hereto as Exhibit 224.

[685] 40 C.F.R. §51.100(s).

[686] Fiore, A.M., J.J. West, L.W. Horowitz, V. Naik, and M.D. Schwarzkopf (2008) "Characterizing the tropospheric ozone response to methane emission controls and the benefits to climate and air quality," *J. Geophys. Res*., 113, D08307, doi:10.1029/2007JD009162, attached hereto as Exhibit 225.; Nolte, C.G., A.B. Gilliland, C. Hogrefe, and L.J. Mickley (2008) "Linking global to regional models to assess future climate impacts on surface ozone levels in the United States," *J. Geophys*. *Res*., 113, D14307, doi:10.1029/2007JD008497, attached hereto as Exhibit 226; Dentener, F., D. Stevenson, J. Cofala, R. Mechler, M. Amann, P. Bergamaschi, F. Raes, and R. Derwent, (2005) "The impact of air pollutant and methane emission controls on tropospheric ozone and radiative forcing: CTM calculations for the period 1990-2030," *Atmos. Chem. Phys*., 5, 1731-1755. Open online access: www.atmos-chem-phys.org/acp/5/1731/, attached hereto as Exhibit 227; Shindell, D.T., G. Faluvegi, N. Bell, and G.A. Schmidt (2005) "An emissions-based view of climate forcing by methane and tropospheric ozone," *Geophys. Res. Lett*., 32, L04803, doi:10.1029/2004GL021900, attached hereto as Exhibit 228.

[687] West, J.J., A.M. Fiore, L.W. Horowitz, and D.L. Mauzerall (2006) "Global health benefits of mitigating ozone pollution with methane emission controls," *Proc. Natl. Acad. Sciences* (USA) 103, 3988-3993, www.pnas.org/cgi/doi/10.1073/pnas.0600201103 at 3989, attached hereto as Exhibit 229

that catalyze oxidation of methane (e.g. NO_x) are more prevalent. This means that methane reductions will be most effective in reducing ozone in regions which are not in attainment, or are close to non-attainment, for ambient air quality standards for ozone, and where the negative affects of ozone are most acute.

In addition, Wild *et al.* analyzed projections of future emissions for the next several decades and how those emissions will affect surface ozone.[688] Their analysis predicts that global methane emissions will be the most important determinant of whether surface ozone in North America drops over the coming decades, or remains about constant.[689] If ozone remains near present levels, many areas will continue to struggle with attainment of the ambient air quality standard, and as a result public health and welfare will suffer. Their study shows "the increasing importance of limiting atmospheric methane growth as emissions of other precursors are controlled."[690]

Ground-level ozone has significant and well-documented negative impacts on public health and welfare. Some studies have documented how reductions in ground-level ozone resulting from methane emissions reductions in particular will benefit public health and welfare. A global 20% reduction in anthropogenic methane emissions would prevent 14,100 – 40,100 premature deaths in the northern hemisphere.[691]

Using a global value of a statistical life (VSL) of $1 million (substantially lower than the value used by EPA, currently $7.4 million (in 2006 dollars)[692]), West *et al.* calculate a monetized benefit from avoided mortality due to methane reductions of $240 per metric ton (range of $140 - $450 per metric ton).[693]

Ground-level ozone also significantly reduces yields of a wide variety of crops. A recent study finds that in 2000, ozone damage reduced global yields 3.9-15% for wheat, 8.5-14% for soybeans, and 2.2-5.5% for corn, with total costs for these three crops of $11 billion to $18 billion and costs within the US alone over $3 billion (all in year 2000 dollars).[694] Due to the growth in the emissions of ozone precursors in coming years, these crop losses are likely to increase. In 2030, ozone is predicted to reduce global yields 4-26% for wheat, 9.5-19% for soybeans, and 2.5-8.7% for corn, with total costs for

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[688] Wild, O., *et al,* (2011) "Modelling future changes in surface ozone: a parameterized approach," *Atmos. Chem. Phys. Discuss.*, 11, 27547–27590. Open online access: www.atmos-chem-phys-discuss.net/11/27547/2011/, attached hereto as Exhibit 230.
[689] Wild *et al.* figures 8 – 10, at 27,586 – 27,588.
[690] Wild *et al.* at 27,549.
[691] Anenberg, S.C., *et al.* (2009) "Intercontinental impacts of ozone pollution on human mortality," *Environ. Sci. & Technol.*, 43, 6482-6487, doi: 10.1021/es900518z, attached hereto as Exhibit 231
[692] http://yosemite.epa.gov/ee/epa/eed.nsf/pages/MortalityRiskValuation.html, attached hereto as Exhibit 232
[693] West *et al.* at 3991.
[694] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296, attached hereto as Exhibit 233

these three crops (2000 dollars) of $12 billion to $35 billion.[695] Another recent study included damage to rice (3-4% reduction in yield for year 2000) and finds even higher total costs for year 2000 ($14 billion to $26 billion).[696] Many other crops are damaged by ozone, so these estimates only capture a portion of the economic damage to crops from ground-level ozone. The value of avoiding a portion of these damages by reducing methane emissions must be considered in valuation of methane reductions.

Avnery *et al*.[697] report work underway to examine the benefits to crop yields from methane mitigation. This study, which will provide an estimate of the value of increased crop yields resulting from avoided ozone damages resulting from methane emission reductions, is currently under peer-review for publication in a scientific journal. We will submit this study as soon as it has been accepted for publication, so that EPA may consider it in order to provide a more accurate valuation of methane reductions.

Damages to human health and crops from ozone produced by methane emissions are independent of damages to human health and welfare resulting from the temperature increases and other negative consequences of climate change due to methane emissions.[698] Thus, a full accounting of benefits from methane reductions must include the sum of the climate-related benefits discussed above and the ozone-related health and crop yield benefits.

VIII. INDUSTRY GROWTH AND RIGOROUS CLEAN AIR REGULATIONS CAN GO HAND IN HAND

Despite the clear economic benefits of EPA's rules, we expect some commenters to argue that the rules will restrain the industry's growth. On the contrary, as we demonstrate below, air quality standards are compatible with successful natural gas expansion efforts.

A. Experience from Colorado and Wyoming, where industry has grown in the presence of strong standards.

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[695] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 2. Year 2030 potential crop production losses and economic damage under two scenarios of O_3 pollution," *Atmos. Env.*, 45, 2297-2309, attached hereto as Exhibit 234.

[696] Van Dingenen, R, F.J. Dentener, F. Raes, M.C. Krol, L. Emberson, and J. Cofala, (2009) "The global impact of ozone on agricultural crop yields under current and future air quality legislation," *Atmos. Env.*, 43, 604-618, attached hereto as Exhibit 235.

[697] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296.

[698] These negative consequences from emissions of methane, independent of climate change, could be included in integrated assessment models used in the calculation of SCM. However, the model used by Marten and Newbold (see above) does not include these damages, so they must be added to the SCM. If the present benefit of methane reductions is calculated by multiplying the social cost of carbon by a global warming potential (see above) then damages independent of climate change inherently must be added, as that method cannot capture damages independent of climate.

EPA's proposed standards are similar to existing state-level regulations in Colorado and Wyoming, where compliance has not only been accomplished, but has been accompanied by rapid growth in the oil and natural gas industries. As John Corra, Director of the Wyoming Department of Environmental Quality, recently told a Department of Energy advisory panel on natural gas issues, thanks to several years of protective air emission limitations, the number of wells and gas production in active parts of WY have gone up, while air emissions have gone down.[699]

We have examined several metrics illustrating trends in the oil and natural gas sectors which show that both Colorado and Wyoming have experienced growth in those industries while meeting state air regulations, and in some cases, higher growth than both the U.S. overall and other states without such regulations. While this analysis does not quantify the impact of the regulations, (since we do not know what sort of growth these states might have seen in their absence), it does provide evidence that industry can thrive in the presence of these regulations.[700]

B. Regulatory Background in Colorado and Wyoming

Regulations to control emissions of VOCs and HAPs from oil and natural gas operations have been in place in Wyoming for over a decade and in Colorado since 2004. WY first introduced regulations for minor source crude oil, gas, and condensate production sources in October 1995. In 1997, the state lowered the applicability threshold for its minor source permitting program in response to "prospects of increased natural gas development in Southwest Wyoming and other parts of the state."[701] Wyoming promulgated presumptive best available control technology (BACT) guidance requiring oil and gas production facilities to control VOCs and HAPs associated with flashing losses from pressure vessels and storage tanks on January 6, 1999.[702] These requirements applied to new wells and recompletion or stimulation projects. WY subsequently strengthened its BACT requirements, first in August 2001 and again in 2004 and 2007, increasing the source types covered and stringency - with the most recent revision in March 2010. The current presumptive BACT guidance requires differing levels of control of emissions from well completions, pneumatic controllers and pumps, glycol

[699] See video of the July 13, 2011 meeting of the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board; Mr. Corra's presentation starts near the mid-way point. www.shalegas.energy.gov/media/Meeting_071311_Afternoon.html

[700] While this analysis does provide evidence that industry can thrive in the presence of regulation, it is important to understand its limitations. For example, there are a number of additional factors that may contribute to relative growth between states that have not been examined here. These factors include (but are not limited to) the relative potential between states for growth in terms of physical availability or access to resources, as well as general economic health at the local/regional level.

[701] http://deq.state.wy.us/aqd/Oil%20and%20Gas/052297.pdf, attached hereto as Exhibit 236

[702] http://deq.state.wy.us/aqd/Oil%20and%20Gas/oglette.pdf. Although we discuss the substance and effect of Wyoming's presumptive BACT regulations, we do not endorse the presumptive BACT concept as a matter of policy and law.

dehydrators, flash emissions from storage vessels, and separation vessels, depending on the location of the operations. More stringent requirements apply in areas of intense development, e.g. concentrated areas of development and in the immense Jonah and Pinedale Anticline development areas.

Colorado first introduced rules to limit emissions of VOCs and NO_x from oil and natural gas exploration and production facilities in ozone non-attainment (NA) areas in March 2004. Specifically, Regulation No. 7 required control of emissions from condensate operations with the potential for flash emissions, glycol dehydrators, gas processing plants and reciprocating internal combustion engines. In December 2006, Colorado revised Regulation No. 7 to require a greater level of control for condensate tanks located in the Denver metro ozone nonattainment area, and extended controls for dehydrators and condensate tanks statewide. In December 2008, Colorado added a requirement to control emissions from pneumatic devices located in ozone nonattainment and maintenance areas and extended the requirements to control NOx emissions from reciprocating internal combustion engines statewide. In 2009, the Colorado Oil and Gas Conservation Commission (COGCC) promulgated additional rules that have the effect of reducing emissions from glycol dehydrators and storage tanks located in the Piceance basin and well completions and pneumatic devices located statewide. These rules took effect in the spring of 2009.

C. Growth Trends

There are a number of possible metrics that can be used to measure the growth trends in the oil and natural gas industries in these states—we've focused on three data sets: operational rotary rig count, producing natural gas wells, and natural gas gross withdrawals. Data on rig count is from Baker Hughes and is available through 2010; data on gas wells and withdrawals is from the U.S. Department of Energy's Energy Information Administration (EIA) and is available through 2009.

D. Operational Rig Count

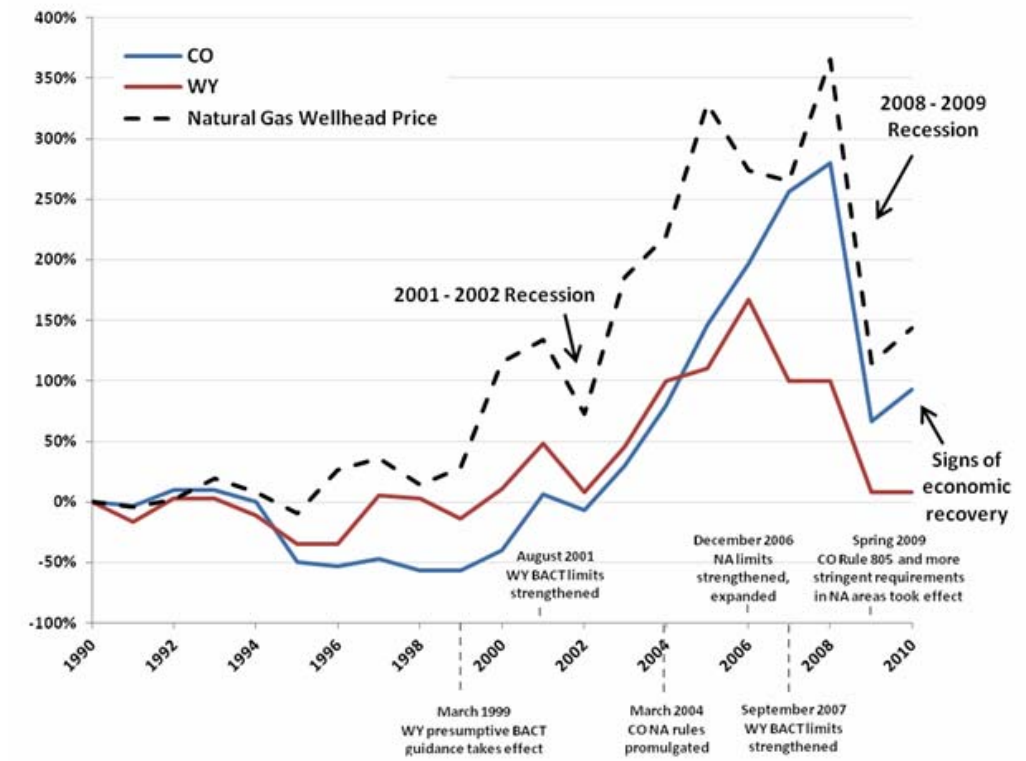
The data show that rig counts in Colorado and Wyoming have shown significant growth during the years of regulation, in some cases even higher than other states which do not have such regulations.[703] Colorado's growth has been particularly high, with an average annual growth rate over the 2000-2010 period of nearly 21%, higher than states such as Texas, Oklahoma, New Mexico, and Louisiana (states without similar air regulations) – this figure is also higher than the overall U.S. annual growth rate of about 12%.

[703] According to Headwater Economics, rig count serves as a good proxy for economic trends, and in particular, employment trends, since the majority of oil and gas industry jobs are associated with the drilling phase. Headwaters Economics, "Drilling Rig Activity Nears Twenty-Year High: Price and Technology Remain Key Drivers of Oil and Gas Drilling Activity", http://headwaterseconomics.org/wphw/wp-content/uploads/RigCounts.pdf (10 June 2011), attached hereto as Exhibit 237.

Colorado's rig count in 2010 was about triple what it was in the year 2000, while overall U.S. rig count did not quite double. The state's rig count growth is particularly high in the few years after 2004, exactly the year that the Regulation No. 7 rules went into effect.

While Wyoming's rig counts decrease following 2006, the data shows a generally increasing trend over the previous ten years during which regulations of some form were in place in the state, suggesting that rig counts are more responsive to factors other than regulation. Indeed, the trend in rig count in both Wyoming and Colorado closely follows that of natural gas prices, and shows notable decreases in the presence of a recession (e.g. 2001-2002, 2008-2009) – factors which appear to impact rig count more than the presence of regulation (see Figure 1). More recently, between 2009 and 2010, Wyoming's rig count leveled out, and Colorado showed signs of recovery, with a 16% increase in number of rigs.

Figure 8: Growth in Number of Rigs in WY and CO and Natural Gas Price Relative to 1990[704]



Sources: Based on rig count data from Baker Hughes[705] and natural gas wellhead price data from EIA.[706]

E. Permit Applications

Industry activity can also be represented through the number of permit applications for oil and natural gas development projects. In WY, for instance, a number of very large oil and gas projects are poised for approval on federal lands. The Bureau of Land Management (BLM) is currently preparing environmental impacts statements for the nearly 9,000-well Continental Divide Creston project, the 4,208 well Hiawatha project, the 1,861-well Moxa Arch project, the 3,500-well Normally Pressured Lance project, and the 838-well LaBarge Platform project.[707] All of these projects are moving forward while in the presence of WY rules regulating emissions from the oil and gas sector.

F. Producing Natural Gas Wells and Gross Natural Gas Withdrawals

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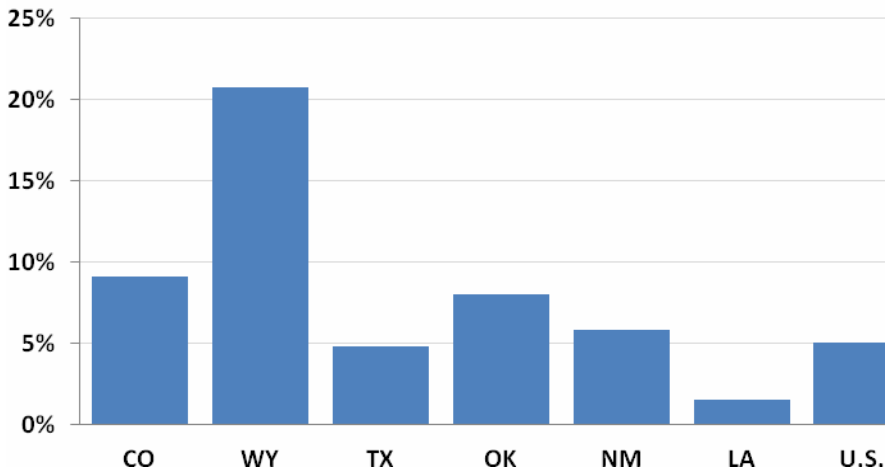
[704] 1990 was selected as the base year, as a year with all data available and early enough to be unaffected by the introduction of the first regulations on the oil and natural gas industries in Wyoming in 1995.
[705] http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm, attached hereto as Exhibit 238.
[706] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm, attached hereto as Exhibit 239.
[707] http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA.Par.24843.File.dat/hot_sheet.pdf, attached hereto as Exhibit 240.

Colorado and Wyoming similarly show strong growth when considering other metrics: producing natural gas wells and gross natural gas withdrawals. In terms of the number of producing gas wells, they show the highest annual growth rates of the states examined with about 9% and 21% average annual growth rates respectively during the period 2000 to 2009, and higher than the average annual growth rate for the U.S. overall at 5% (see Figure 2).[708]

Figure 9: Average Annual Growth of Producing Natural Gas Wells in Selected States and the U.S., 2000-2009

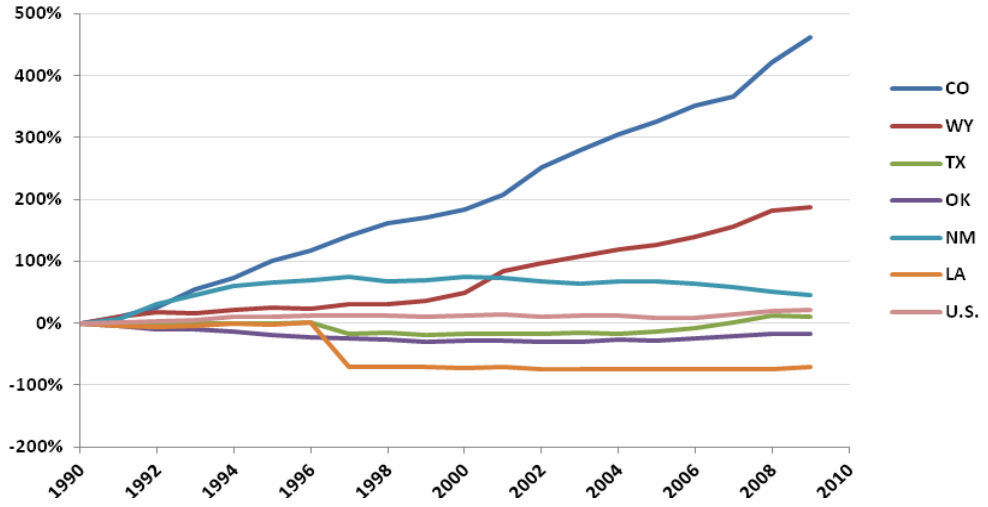


Sources: Based on data from EIA.[709]

Similarly, the two states also have the highest annual growth rates for gross withdrawals, both with average annual growth rates of about 8% over the same period, and higher than the overall U.S. growth rate of 1%.[710] Figure 3 shows that Colorado and Wyoming experienced more rapid growth in gas production than other selected states without similar regulations as well as the U.S. overall when examining the growth in withdrawals relative to 1990.

[708] Compared to 5%, 8%, 6%, and 2% for Texas, Oklahoma, New Mexico, Louisiana, (all states without similar state regulations), respectively.
[709] http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm, attached hereto as Exhibit 241.
[710] Compared to 3%, 2%, -2%, and -0.1% for Texas, Oklahoma, New Mexico, Louisiana (all states without similar state regulations), respectively.

Figure 10: Growth in Natural Gas Gross Withdrawals in Selected States and the U.S. Relative to 1990



Sources: Based on data from the EIA.[711]

The increase in the economic value of the oil and natural gas withdrawn in these states is also a strong indicator of the economic health of these states' oil and gas industries. For example, in 2010 the total value of taxable minerals in Wyoming was $15.5 billion, up 23% from 2009 and second only to the production value in 2008. The taxable value of oil production in Wyoming was $3.27 billion in 2010, up 34% from 2009, and the taxable value of natural gas production was $7.6 billion, up nearly 30% from 2009. [712]

Again, while we cannot quantify the impact of the regulations in Colorado and Wyoming, the bottom line is that CO and WY have shown considerable growth in these industries throughout the years of regulation—regulation comparable to the EPA's proposed federal rules. EPA's proposed rules therefore are not likely to impair the industry's growth; they will, instead, reduce the environmental impacts of that growth.

IX. EPA MUST PROMULGATE THE FINAL STANDARDS NO LATER THAN APRIL 3, 2012

Some oil and gas industry interest groups have asked EPA to delay implementation of the new source performance standards, in some instances, for up to one year.[713] We strongly oppose such requests. First they are contrary to the statute, which requires new sources on which construction is commenced after the date on which new standards are *proposed* to meet the standards once they begin operations.[714] Furthermore, EPA has already agreed to delay promulgation of the final rule to April 3,

[711] http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.
[712] http://taxappeals.state.wy.us/2011%20Abstract%20and%20Mill%20Levy%20Report.xls.
[713] For example, in a public announcement describing the rules as "reasonable" API requested an additional year to comply. SNL Daily Dose, Gas Edition, Sept. 28, 2011.
[714] 42 U.S.C. §§ 7411(a)(2), 7411(b)(1), 7411(e).

2012. This delay provides the industry with a full eight months from the time EPA first publicly announced the rules to final promulgation to ensure that new sources will meet the standards once they commence operations. We strongly oppose industry's claim that additional time is needed; indeed, additional time will prolong EPA's violation of its duty to review and revise the standards.

A. The Standards Can and Must Be Implemented Quickly, as a Matter of Law and Practice

As we have noted, standards to reduce air pollution from the thousands of emission points in the oil and gas sector are already long over-due. Under the statute, a review of the NSPS was required over a decade ago.[715] Similarly, a review of the NESHAPs for major sources must have occurred by 2007.[716] Due to EPA's failure to review and revise the current standards, the industry has operated under outdated and insufficient standards for far longer than Congress intended or mandated, at the expense of human health and environmental welfare. Expeditious promulgation of the final rules and compliance therewith is necessary to fulfill EPA's duty to protect human health and the environment.

Futhermore, the standards do not drive the adoption of new or novel control technologies. They largely codify best management practices already in use by many companies and required in California, Wyoming, and Colorado, among other places. Industry can readily implement these standards, even if EPA improves their rigor, as the statute requires and as we discuss above. Moreover, the standards largely apply only to new and modified sources on which construction has not yet commenced, and do not require the cessation of ongoing operations at existing sources. In fact, the only standard that applies to existing sources is the requirement that existing hydraulically fractured wells utilize reduced emission completions during re-completions.[717] Importantly, this requirement does not require an expensive or technically difficult retrofit, either, but rather simply requires that operators utilize the common best management practice of capturing natural gas, rather than venting or flaring it.

B. Even if Additional Delay Were Legally Permissible, It Would Be Unreasonable, as Industry Experience and State Regulation Near-Term Show Compliance Is Possible

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[715] 42 U.S.C. § 7411(b)(1)(B) (requiring EPA to "review and, if appropriate, revise" NSPS "at least every 8 years."). EPA promulgated the existing NSPS for the Crude Oil and Natural Gas Source Category in 1985: "Equipment Leaks of VOCs From Onshore Natural Gas Processing Plants", 50 Fed. Reg. 26122 (June 24, 1985), codified at 40 C.F.R. § 60.630; "Onshore Natural Gas Processing SO_2 Emissions", 50 Fed. Reg. 40158, 40 C.F.R. §60.640 (1985).

[716] 42 U.S.C. § 7412(d)(6) (requiring EPA "review, and revise as necessary" NESHAPs "no less often than every 8 years,"). EPA promulgated the existing NESHAPs for major sources in the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories in 1999: "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage", 64 Fed. Reg. 32610 (June 17, 1999), attached hereto as Exhibit 242.

[717] 76 Fed. Reg. at 52,799-800 (Proposed 40 C.F.R. § 60.5375).

The proposal codifies best management practices and technologies already in use by numerous companies.[718] These requirements are hardly technology forcing, or even novel, and must have come as no surprise to the regulated community—many of whom tout the proposed equipment and work practice standards as models of efficiency and savings. For example, Devon Energy, an operator in the Barnett Shale, reported saving 15.9 Bcf of gas between 1990 and 2007 from its use of reduced emission completions.[719] Devon also reported a $22 million increase in net gas-sale value between 2004 and 2007 due to implementing reduced emission completions.[720] Similarly, as noted at p. XX of these comments, numerous companies including BP, QEP Resources Inc., Shell Upstream Americas, Ultra Petroleum, Devon Energy, and EnCana have replaced high with low or no-bleed pneumatic devices and have realized considerable natural gas and monetary savings.

Colorado and Wyoming have adopted similar rules to those proposed by EPA. Colorado's most recent set of performance standard regulations provided industry five months to comply.

Colorado provided owners and operators of affected oil and gas facilities five months to comply with the state's most recent and comprehensive set of regulations promulgated by the Colorado Oil and Gas Conservation Commission ("COGCC"). These rules, which were adopted on Dec. 11, 2008 by the COGCC, took effect for owners or operators on state lands within four months (by April 1, 2009) and within five months for owners and operators operating on federal lands (May 1, 2009).[721] Like the NSPS, these rules required the use of low or no-bleed pneumatics at exploration and production sites, reduced emission completions statewide and 95% control of VOC emissions from condensate and crude oil storage tanks with the potential to emit ("PTE") 5 tons per year of VOCs located near public places in the Piceance basin.[722]

Colorado's Department of Public Health and Environment ("CDPHE") provided owners and operators of oil and gas facilities used in exploration and production activities less than five months to comply with its most recent rules to limit VOC emissions from oil and gas sources. The CDPHE finalized rules to limit emissions of ozone precursors in December 12, 2008. The rules require owners and operators of *existing* high-bleed pneumatic devices to replace them with low-bleed devices within five months, by May 1, 2009. Owners and operators of new and modified tanks were given until February 1, 2009 to comply with system-wide percentage reduction requirements and all tanks

[718] See e.g. infra pps xxx (discussion of EPA's consideration of costs).
[719] The American Oil & Gas Reporter, "Reducing Emissions Can Boost Profits", July 2007, http://www.epa.gov/gasstar/documents/aogr_2007.pdf, attached hereto as Exhibit 243.
[720] *Id*.
[721] COGCC Final Rules, Rule 805(b)(2).
[722] *Id*.

associated with new, re-completed or otherwise stimulated wells needed to control VOC emissions by 95% during the first 90 days of production.[723]

As Table 11 shows, Wyoming has required compliance with its presumptive BACT guidance upon the date of final revision or shortly thereafter. We note that we discuss Wyoming's presumptive BACT guidance solely to show what standards are possible, and what compliance times are reasonable. We do not endorse "presumptive BACT" as a legal matter.

Table 11

BACT REVISION	CONTENT	DATE PASSED	EFFECTIVE DATE
1998 revision	Established presumptive BACT requirements for storage tanks and pressure vessels with PTE 40 TPY VOC or more flash emissions	November 20, 1998	March 1, 1999
Chapter 6, Section 2 Permitting Guidance, Revision[724]	Lowered presumptive BACT requirements for storage tanks and pressure vessels to PTE 40 TPY VOC flash emissions and glycol dehydrators with PTE 15 TPY VOCs or 7 TPY total HAP	August 2001	N/A[725]
Jonah and Pinedale Anticline Gas	Lowered emission threshold for	July 28, 2004	Immediately

[723] CO Reg. 7, XII.D.1.
[724] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision http://deq.state.wy.us/aqd/Oil%20and%20Gas/GUIDANCE2001.pdf (August 2001), attached hereto as Exhibit 244.
[725] Wyoming did not publish an effective date on this guidance and conversations with Wyoming DEQ personnel have not been able to confirm a specific date.

Fields, Addition to Oil and Gas Production Facility Emission Controls and Permitting Requirements[726]	controls of flash emissions to 30 TPY, required quicker installation of flash emission controls and lowered emission threshold for controls on glycol dehydrators to 5 TPY total HAPs.		
Chapter 6, Section 2 Permitting Guidance, Revision[727]	Extended 5 TPY HAP applicability to sources located statewide; lowered applicability threshold for flash emissions to 20 TPY VOCs. Tightened Jonah and Pinedale Anticline requirements.	August 2007	September 1, 2007
Chapter 6, Section 2 Permitting Guidance, Revision[728]	Broadened scope of requirements to apply to greater number of sources and developed tiered	March 2010	August 1, 2010

[726] Wyoming DEQ, Air Quality Division, Revision Jonah and Pinedale Anticline Gas Fields, Addition to Oil and Gas Production Facility Emission Controls and Permitting Requirements, July 28, 2004, http://deq.state.wy.us/aqd/Oil%20and%20Gas/JONAH%20INFILL%20GUIDANCE%20FINAL%207-28-04.pdf., attached hereto as Exhibit 245.

[727] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision, http://deq.state.wy.us/aqd/Oil%20and%20Gas/AUGUST%202007%20O&G%20GUIDANCE%20-%20FINAL.pdf. attached hereto as Exhibit 246.

[728] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision, http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf. attached hereto as Exhibit 247.

	level of controls depending on location of source.		

With the exemption of compressors, all of the sources covered by EPA's proposal are currently subject to standards requiring similar levels of control by the states of Wyoming and Colorado. These states required compliance immediately, or in some instances, within months of final rule adoption even where retrofits of existing sources of air pollution were required to meet the standards. Accordingly, eight months is more than enough time for new sources in the oil and gas industry to meet with the new source performance standards. And again, this is particularly true because the standards require demonstrated practices in use by industry and do not require expensive retrofits of existing sources.

X. EPA MUST PROMULGATE AN ENFORCEABLE TIMELINE TO SWIFTLY ADDRESS REMAINING GAPS IN THE NSPS

Just as EPA must implement the standards it has proposed swiftly, it must commit to filling gaps in those standards quickly. As we have described above, the standards suffer from significant gaps, which are contrary to law. They (1) fail to control certain important facility types (such as liquids unloading from wells and heater-treaters); (2) they fail to control certain pollutants (such as PM, methane, and hydrogen sulfide); and (3) they fail to control existing sources. As we have explained, EPA must correct these failings.

That said, we understand that EPA must propose rules to address some of these failures before it can issue final rules, and that EPA must not (and must not) delay finalizing the rules it has proposed. This procedural necessity does not, however, allow EPA to simply avoid complying with its statutory obligations, and certainly does not allow EPA to put off fixing its flawed rulemaking until the next review cycle, eight years from now.

Instead, both to demonstrate that it will comply with the statute, and to provide industry with a clear regulatory calendar, EPA must set out an enforceable schedule, in the final rule issued in April, stating when it will propose, and then finalize, rules addressing each of the illegal gaps in the standards that we have identified.

EPA took precisely this step in its "Tailoring Rule," which sets out how EPA will implement the statutorily-required Prevention of Significant Deterioration program for greenhouse gases. Because EPA was unable to fully implement the program on the statutory timeline, it set out "an enforceable commitment to act" to fulfill its obligations by a date certain.[729] Without excusing its failures here, the agency must do the same,

[729] 75 Fed. Reg. 31,514 31,525 (June 3, 2010); *see also* 40 C.F.R. § 71.13 (codifying this commitment).

setting out a timeline for further action that is substantially shorter than the eight years of the NSPS review period. We ask that EPA complete the remaining rulemaking no later than 2013, which, though countenancing a long and illegal delay, will offer the agency some time to complete its work.

XI. CONCLUSION

Thank you for considering these comments. We look forward to working with EPA to strengthen the proposed rules so that the final rules will better protect communities across the country.

Sincerely,

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[730] With thanks to legal interns Paul Heberling and Jared Fish.

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 7

Joint Comments on the New York State RDSGEIS (January 11, 2012)

January 27, 2012

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find the comments of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council and Riverkeeper on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011, and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011.

Sincerely,

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Comments Summary Report: Expert Team Review of the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations

1.0 Introduction

The Louis Berger Group, Inc. (LBG) is pleased to submit this comment report on the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program and Proposed High Volume Hydraulic Fracturing (HVHF) Regulations to the Natural Resources Defense Council (NRDC) and its partner organizations, Earthjustice, Riverkeeper, Delaware Riverkeeper Network and Catskill Mountainkeeper. This comment report serves two primary purposes: 1) to provide general comments on the RDSGEIS and proposed regulations that are not limited to specific disciplines, and 2) to summarize the discipline-specific technical comments from NRDC's expert review team. The expert review team consisted of Harvey Consulting, LLC, Dr. Tom Myers, Dr. Glenn Miller, Dr. Ralph Seiler, Dr. Susan Christopherson, Meliora Design LLC, LBG, Kevin Heatley, Dr. Kim Knowlton, Dr. Gina Solomon, and Briana Mordick. The detailed technical comments from each author/organization are provided as attachments to this summary report and referenced as appropriate throughout.[1] Table 1 provides a complete list of technical comment attachments and summarizes the major topics areas addressed in each. Resumes for the members of the expert review team are provided in Attachment 12.

2.0 General Comments

2.1 RDSGEIS Fails to Address "Other Low-Permeability Shales"

The final scope and title of the RDSGEIS included other low-permeability shales, in addition to the Marcellus shale. The RDSGEIS makes it clear that development of other shales (including the Utica shale) is not only possible in the future, but is considered likely as evidenced by the inclusion of development of other shales in the Ecology & Environment. Inc. economic impact assessment.[2]

[1] All references cited and relied upon in the attached reports are hereby incorporated by reference into these comments. Hard and/or electronic copies of all references are available upon request.
[2] See the 11/23/2011 email from Steven Russo (NYSDEC) to Deborah Goldberg (Earthjustice) explaining the assumptions used in developing the scenarios for economic impact assessment include the development of "other shales."

Table 1
Technical Attachments to the Summary Comment Report

Attachment Number	Preparer	Topics Addressed
1	Harvey Consulting, LLC	Scope of SGEIS - Marcellus Shale Only Liquid Hydrocarbon Impacts Water Protection Threshold Well Casing Requirements Permanent Wellbore Plugging &Abandonment Requirements HVHF Design and Monitoring Hydraulic Fracture Treatment Additive Limitations Drilling Mud Composition and Disposal Reserve Pit Use and Drill Cutting Disposal HVHF Flowback Surface Impoundments at Drillsite HVHF Flowback Centralized Surface Impoundments Off-Drillsite Repeat HVHF Treatment Life Cycle Air Pollution Control and Monitoring Surface Setbacks from Sensitive Receptors Naturally Occurring Radioactive Materials Hydrogen Sulfide Chemical Tank, Waste Tank and Fuel Tank Containment Corrosion and Erosion Mitigation and Integrity Monitoring Programs Well Control and Emergency Response Capability Financial Assurance Amount Seismic Data Collection
2	Tom Myers, Ph. D.	Hydrogeology and Contaminant Transport Surface Water Hydrology Groundwater Quality Monitoring Setbacks from aquifers and public water supply wells Acid Rock Drainage
3	Glenn Miller, Ph.D.	Toxicology Hydraulic Fracturing Additives Naturally Occurring Radioactive Materials Contaminants in Flowback water and produced brines Wastewater Treatment issues
4	Ralph Seiler, Ph.D.	Radon in Marcellus Shale Natural Gas Naturally Occurring Radioactive Materials
5	Susan Christopherson, Ph.D.	Socioeconomic Impacts Pace and timing of natural gas development
6	Meliora Design, LLC	Water Quality Stormwater Erosion SPDES General Permit
7	The Louis Berger Group, Inc.	Noise and Vibration Visual impacts Land use Transportation Community character Cultural resources Aquatic Ecology
8[3]	Kevin Heatley, M.EPC LEED AP	Ecosystems and Wildlife
9	Kim Knowlton, DrPH	Climate Change and Public Health
10	Gina Solomon, M.D., M.P.H	Health Impact Assessment
11	Briana Mordick	Induced Seismicity

[3] Report prepared for and provided courtesy of the Delaware Riverkeeper Network.

The RDSGEIS adds some additional baseline geologic information on the Utica shale, but the environmental impacts specific to the Utica shale have not been addressed. For example, the Utica shale is almost twice as deep as the Marcellus shale, which means wells in the Utica shale will take longer to drill, would create more noise, would require more water, and would generate more waste and truck trips than wells in the Marcellus shale.

In addition to the incomplete study of deeper depth low permeability gas reservoirs, gas reservoirs at shallower depths than the Marcellus shale were not studied at all in the RDSGEIS. These shallower low-permeability shales pose development risks greater than those associated with the Marcellus shale because they are closer to protected water resources. Furthermore, the combined and/or concurrent exploitation of low-permeability shales at multiple depths may result in cumulative impacts not addressed in the RDSGEIS. The absence of the impact analyses of exploitation of shales at depths other than the Marcellus shale renders the RDSGEIS incomplete. NYSDEC should either evaluate additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the RDSGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

For additional detailed information supporting this comment, refer to Chapter 2 of the 2011 Harvey Consulting, LLC report (Attachment 1).

2.2 RDSGEIS and Regulations Fail to Protect the Environment from Non-HVHF Gas Development

While significant gaps remain as identified throughout these comments, the proposed regulatory framework for HVHF includes a number of improvements to NYSDEC's existing regulations to protect the environment from natural gas development. However, most of these improvements apply only to wells meeting the threshold to be classified as HVHF (defined as hydraulic fracturing using greater than 300,000 gallons of water).[4] NYSDEC is using a patchwork approach to regulating HVHF by adding new requirements on top of outdated requirements. A broader reform of the oil and gas development regulations is needed to address deficiencies in the existing regulations. This will ensure that best practice approaches are required for all natural gas wells in New York, including conventional wells and hydraulic fracturing using less than 300,000 gallons of water. Examples of reforms incorporated into the RDSGEIS and/or proposed regulations for HVHF that should apply to all wells include updated well casing requirements, emergency response plans and plans addressing the mitigation of noise, visual, transportation and ecological impacts.

2.3 RDSGEIS Fails to Address Indirect and Cumulative Impacts

The RDSGEIS fails to analyze important indirect and cumulative impacts as required by the State Environmental Quality Review Act (SEQRA). One of the most glaring examples of this is the

[4] The RDSGEIS arbitrarily increased the threshold for HVHF to 300,000 gal from 80,000 gal, as evaluated in the 1992 GEIS. There is no scientific justification given for the increase, and it effectively leaves all fracturing in the range 80,000-300,000 regulated by the existing rules without NYSDEC ever having conducted an environmental review showing that they are adequate for jobs that big.

RDSGEIS's failure to analyze the impacts of the pipelines and compressor stations that would be required to support the development of HVHF.

The RDSGEIS does not analyze any of the important impacts of pipelines and compressor stations (such as additional habitat fragmentation, noise and air pollutant emissions) based on flawed reasoning that such an analysis is not required because the pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant—SEQRA requires state and local agencies to consider indirect "growth inducing" impacts. Pipelines and compressor stations are an indirect effect of the approval of HVHF. Without the approval of HVHF, there would be no reason to construct additional pipelines. Therefore, the pipelines/compressor stations and associated impacts cannot be separated from the environmental impact analysis of the HVHF regulatory program. The separate environmental review of the pipelines is, moreover, a form of segmentation, which is not permissible under SEQRA.[5] The additional natural gas pipelines and related infrastructure could also result in cumulative impacts when their impacts are combined with the impacts of HVHF that were analyzed in the RDSGEIS. The result of these deficiencies in the RDSGEIS is that the true impacts of the approval of HVHF have not been disclosed to the public and the requisite "hard look" under SEQRA has not been taken.

Similar to the treatment of pipeline infrastructure, the RDSGEIS also fails to analyze the cumulative impacts of numerous actions related to HVHF moving forward in New York, including the following:

- **Impacts from wastewater disposal and management**. The wastewater produced during the HVHF process is highly contaminated and could impact water resources if released into groundwater or surface water. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

- **Impacts from Centralized Flowback Impoundments.** The RDSGEIS fails to analyze the impacts of centralized flowback impoundments based on statements from industry that they will not be "routinely" proposed. While site-specific SEQRA review would be required for any centralized flowback impoundment, NYSDEC should have addressed the potential for significant adverse cumulative impacts (particular air quality and water resources) arising from centralized flowback impoundments in combination with the other impacts of HVHF discussed in the RDSGEIS.

- **Impacts from seismic data collection.** Seismic data collection has the potential to create

[5] See 6 § NYCRR (617.2(ag)): "Segmentation means the division of the environmental review of an action such that various activities or stages are addressed under this Part as though they were independent, unrelated activities, needing individual determinations of significance."

habitat fragmentation through the clearing of long linear corridors, among other impacts. Seismic data collection is a reasonably foreseeable part of the development process and should have been considered as an aspect of the cumulative effects assessment in the RDSGEIS.

- **Impacts from liquid petroleum.** The development of the Marcellus shale has the potential to result in wells the encounter liquid hydrocarbons. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be proposed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. None of these impacts were considered in the RDSGEIS.

- **Impacts from land use change**. The RDSGEIS contains some information about potential economic benefits, but does not examine how increase population and employment would change land use. Changes in land use would result in greater demands on the transportation system as well as ecological impacts from new residential and commercial development (above and beyond the direct impacts of the well pad sites themselves).

Fundamentally, the RDSGEIS analyzes only certain elements of HVHF and fails to analyze all elements of the process, both individually and collectively.

2.4 Unenforceable Mitigation under the HVHF Regulatory Framework

As noted throughout the detailed technical review comments, the RDSGEIS includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or supplemental permit conditions.

To provide a consistent regulatory framework for industry and to protect the environment, mitigation measures that would be applied across all HVHF operations should be incorporated into the proposed regulations. Mitigation measures that are site-specific should be incorporated into the supplemental permit conditions. Mitigation measures that are suggested in the RDSGEIS itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

2.5 Setbacks

As a general matter, the setback requirements stipulated by proposed HVHF regulations are inadequate to protect public health and environmental quality. Table 2 provides a summary of the setbacks proposed in the RDSGEIS and/or regulations and the recommended revisions to the setbacks based on the expert reviews conducted for NRDC.

For example, the minimum setback according to the HVHF regulatory framework for a residence is 100-feet. This is inadequate considering the potential for blowouts to eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. Other risks to residences and schools within close proximity to HVHF operations include noise levels that damage hearing and, exposure to hazardous gases, chemicals, fuels, and explosive charges.

The potential radius of impact for explosions, fire, and other industrial hazards should be considered in the RDSGEIS and proposed HVHF regulations. For example, Fort Worth Texas uses the International Fire Code as the basis for its minimum 600' setback from shale gas drilling operations. The figure below shows how the HVHF regulations setback distance requirements are significantly shorter and thus less protective than the requirements in other locations.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

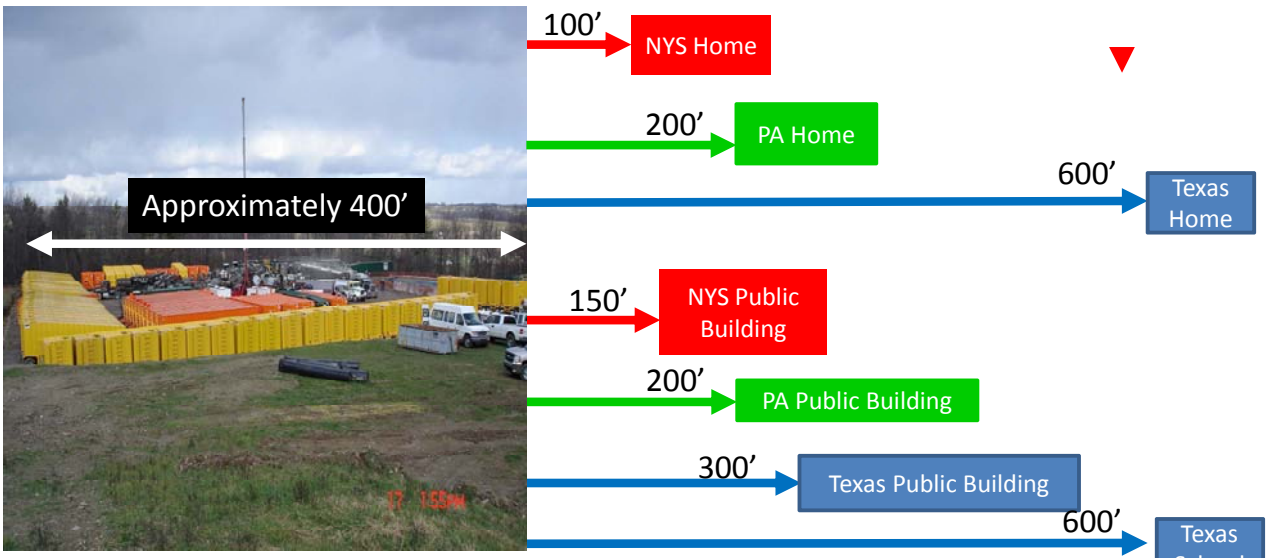

Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

2.6 Insufficient Public Review of HVHF Permit Applications

The RDSGEIS fails to provide a clear and accessible process for public and local government access to site-specific HVHF activity information, while at the same time placing the burden on local government (and not the industry) to provide notice to NYSDEC that a HVHF activity may not be in compliance with local zoning or land use regulations (RDSGEIS pages 8-4 and 8-5). This essentially puts the regulatory burden on local government and at the same time fails to provide local government with access to the necessary information. The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public. NYSDEC should require public notice of the availability of HVHF permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. Permit applicants should be required to provide copies of their application to the affected municipality. The public should have immediate online access to all supporting documentation submitted with each permit application and the public review timeframe should be no less than 30 days. The regulatory framework must incorporate a mechanism for public comments on permit applications to be considered by NYSDEC before the decision to grant or reject a permit application is made.

Table 2
Summary of Setback Recommendations

	Minimum Setback under Existing/Proposed HVHF Regulatory Framework	Recommended Minimum Setback	Rationale/Notes
Residences	100 feet 6 NYCRR § 553.2	1,320 feet	Protects from noise, explosions, fire, and other industrial hazards.
Public Buildings (including schools)	150 feet 6 NYCRR § 553.2		
Primary Aquifers	500 feet 6 NYCRR § 560.4	4,000 feet	The 500 feet setback for primary aquifers should be increased to 4,000 feet (the same setback distance adopted in the RDSGEIS for Filtration Avoidance Determination watersheds), unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.
Principal Aquifers	500 feet in RDSGEIS (page 1-18) but not in the proposed regulations**	4,000 feet	The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.
Public Water Supplies	2,000 feet (6 NYCRR § 560.4)	4,000 feet	The setback for public water supplies should be the same as for principal aquifers (4,000 feet) and the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.
Private Drinking Water Wells	500 feet* (6 NYCRR § 560.4)	4,000 feet	Private and public wells should be protected to the same extent. NYSDEC should not allow the owner to waive the private well setback requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.
Stream, Storm Drain, Lake, or Pond	150 feet**	660 feet	The regulations currently contain conflicting and unclear requirements with respect to surface water resource setbacks. The regulations should be revised provide consistent setback requirements that are protective of water sources, including rivers, streams (perennial and intermittent), and lakes.
Filtration Avoidance Determination Watersheds	4,000 feet in RDSGEIS (page 7-56) but not in the proposed regulations	4,000 feet	Incorporate RDSGEIS setback commitment into regulations. In addition, the operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the FAD watershed.
Floodplains	Wellpads prohibited in the 100-year floodplain (6 NYCRR § 560.4)	Wellpads prohibited in the 500-year floodplain	For wells that might operate for 30 years, there is a 26% chance of a 100-year flood occurring during the period the well would be operated. Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.

*Setback can be waived by the landowner. The proposed regulations do not address setbacks for domestic use springs
** Setback could be waived based on site-specific analysis.

2.7 Impacts of Well Refracture Not Addressed

The assessments of environmental impacts in the RDSGEIS are all based on a single hydraulic fracturing treatment of each well. The RDSGEIS inappropriately relies on informal statements from industry that refracturing will be rare and does not quantify the number of HVHF treatments possible per well. The RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several-decade long lifecycle. The RDSGEIS should quantify 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. Additionally, the RDSGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts. Refer to Chapter 16 of the Harvey Consulting, LLC report (Attachment 1) for more information supporting this comment.

3.0 Summary of Technical Comments

3.1 Liquid Petroleum Impacts

The RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be needed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.

The RDSGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The RDSGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drill sites that may be required to develop oil resources identified by shale gas exploration and production activities.

The comments summarized in this section are covered in greater detail in Chapter 3 of the Harvey Consulting, LLC report (Attachment 1).

3.2 Well Casing Requirements

The comments summarized in this section are covered in greater detail in Chapters 5 through 8 of the Harvey Consulting, LLC report (Attachment 1).

3.2.1 Conductor Casing

Conductor casing is the first string of casing in a well and is installed to prevent the top of the well from caving in. The conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the proposed regulations and should

apply to all natural gas wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

3.2.2 Surface Casing

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well. Stray gas may impact groundwater and surface water from poor well construction practices. Properly constructed and operated gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion. Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania and other locations.

The RDSGEIS and proposed regulations include important improvements for surface casing that incorporate many of the comments provided by this working group in 2009. Notable improvements include requirements related to cement quality, casing quality, and installation techniques. Unfortunately, there are a number of inconsistencies between the permit conditions and the proposed regulations that create uncertainty about what will be required. The Harvey Consulting, LLC report provides recommendations for correcting these inconsistencies. Finally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.3 Intermediate Casing

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The RDSGEIS and proposed regulations include important improvements for intermediate casing in comparison to the 2009 DSGEIS. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. However, the remaining area for improvement in the proposed regulations is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing, on which the proposed regulations are silent. There are also a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.4 Production Casing

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone or, alternatively, it is set just above the hydrocarbon zone. Production casing is used to isolate hydrocarbon zones and to contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier

that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The RDSGEIS and proposed regulations include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the proposed regulations is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and proposed regulations require production casing to be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. The proposed regulations also require the cement placement and bond be verified by well logging tools. These requirements are best practice. The Harvey Consulting, LLC report provides minor additional recommendations to improve consistency of the various requirements for production casing and highlights additional best practices that should be considered.

3.3 HVHF Design and Monitoring

Computer modeling is routinely used by industry to design hydraulic fracture treatments. During actual fracture stimulation treatments, data is collected to verify model accuracy, and the model is continually refined to improve its predictive capability. Data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability. HVHF modeling is an important way of helping to ensure fracture treatments do not extend outside the target formation. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport.

The RDSGEIS does not require well operators to develop or maintain a hydraulic fracture model. Instead, the RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned. Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. Instead, NYSDEC needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and the environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective; it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. Best practices for HVHF design and monitoring should be included as a mitigation measure, and codified in regulations as a minimum standard. These best practices include utilizing hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone.

The comments summarized in this section are covered in greater detail in Chapter 10 of the Harvey Consulting, LLC report (Attachment 1).

3.4 Corrosion and Erosion Mitigation and Integrity Monitoring Programs

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide

(CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves. HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require that facilities be designed to resist corrosion (e.g., material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment. Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be evaluated and codified in regulations. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

The comments summarized in this section are covered in greater detail in Chapter 23 of the Harvey Consulting, LLC report (Attachment 1).

3.5 Well Control & Emergency Response Capability

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. The addition of an Emergency Response Plan (ERP) requirement to the RDSGEIS is a substantial improvement over the 2009 DSGEIS, which failed to address this issue. However, it is recommended that NYSDEC include a review, approval, and audit processes to ensure that quality ERPs are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

The comments summarized in this section are covered in greater detail in Chapter 24 the Harvey Consulting, LLC report (Attachment 1).

3.6 Financial Assurance Amount

NYSDEC ignored comments submitted by this working group in 2009 requesting that the SGEIS examine financial assurance requirements to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination). Although changes in financial assurance amounts would require legislative action, the analysis of this issue is necessary to fully disclose the potential adverse environmental impacts that would result in the absence of adequate financial assurances. Moreover, such an analysis would be an appropriate way of bringing this need for legislation to the attention of elected officials as appropriate mitigation for identified significant adverse impacts.

The importance of reevaluating financial assurance requirements is heightened when the inadequacy of the existing requirements is considered. For wells between 2,500’ and 6,000’ in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000. For wells drilled more than 6,000’ deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based solely on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6). These requirements are

far less than those in other locations. Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well. Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS. In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas.

NYSDEC's financial assurance requirements should not narrowly focus on the costs of plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment. Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be evaluated and included in the proposed regulations.

The comments summarized in this section are covered in greater detail in Chapter 25 of the Harvey Consulting, LLC report (Attachment 1).

3.7 Hydrogeology and Contaminant Transport

The RDSGEIS dismisses the potential for groundwater contamination due to HVHF on the basis of faulty science and unsupported assumptions.

1. The characterization of the hydraulic fracturing process and effects in the RDSGEIS is technically incorrect, leading to important impacts being overlooked.

2. The RDSGEIS assumes that the geologic layers above the Marcellus shale will stop contamination of aquifers without providing sufficient information on these layers, and ignoring the potential for existing faults and fractures to expedite contaminant transport. It also ignores studies which show that hydraulic fracturing has fractured formations as much as 1500 feet above the target shale, thereby providing pathways through the rock which the RDSGEIS relies on for stopping contaminant transport.

3. The RDSGEIS impact analyses are incomplete from a spatial perspective. The analyses focus on *local* impacts and fails to address the *regional* impacts of HVHF on the characteristics of the shale and the environmental implications of these changes. Such changes include increased shale permeability to water flow, which increases the risk of aquifer contamination over time.

4. The RDSGEIS analyses are incomplete from a temporal perspective. The analyses do not address the potential long-term aquifer contamination impacts by focusing on a time period of few days, assuming contamination has not occurred in other locations that lack the monitoring that would be necessary to detect contamination, and not considering evidence of the potential vertical movement of fracking fluid to near-surface aquifers as discovered under comparable conditions elsewhere.

Detailed technical supporting information for the deficiencies noted above is provided in the report prepared by Dr. Tom Myers (Attachment 2). The Myers report also provides a number of important recommendations for:

1. Improving and expanding the characterization of the hydraulic fracturing process and impacts in the RDSGEIS; and
2. Implementing measures as part of the review of specific well site proposals to avoid significant adverse aquifer contamination impacts.

The measures should include the following:

1. Mapping groundwater gradients above the Marcellus shale using existing data.
2. Requiring seismic surveys to locate faults prior to drilling.
3. Implementation of a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport.

The groundwater monitoring at domestic wells proposed in the RDSGEIS is a scientifically improper method of monitoring the location of a contaminant plume because domestic wells are not designed for monitoring. Dedicated monitoring wells are necessary to prevent contamination of water wells by detecting contaminants before they reach the water wells.

3.8 Well Plugging and Abandonment

Wells that are not properly plugged can act as a preferential pathway for surface contaminants to impact groundwater resources. There are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned). As a result, there is a risk that improperly planned HVHF wells or fractures could intersect abandoned wells and contaminate groundwater. Key recommendations from Chapter 9 of the Harvey Consulting, LLC report (Attachment 1) related to well plugging and abandonment (P&A) include the following:

- The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

- The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

- The SGEIS requirements with respect to the plugging of improperly abandoned wells nearby proposed HVHF wells should be strengthened and incorporated in the proposed regulations.

3.9 Seismic Data Collection

Seismic surveys are used by industry to target hydrocarbon formations for exploration and appraisal drilling. Typically seismic surveys are conducted using vehicle-mounted vibrator plates that impact the ground or use explosive to create seismic waves which bounce off of subsurface rock strata and geologic formations. The reflected seismic waves are measured at various surface receivers. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (up to 20'-50' wide). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection.

The RDSGEIS does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys. If 2D or 3D seismic surveys are planned, or are possible in the future, the proposed HVHF regulations should codify a permitting process for these activities and institute mitigating measures in the RDSGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas. In addition, the increased industrial activity (e.g., economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the RDSGEIS.

The comments summarized in this section are covered in greater detail in Chapter 26 of the Harvey Consulting, LLC report (Attachment 1).

3.10 Surface Water Hydrology

The RDSGEIS has addressed many of the deficiencies of the 2009 DSGEIS with respect to the treatment of hydrology issues. As discussed in the Myers report (Attachment 2), NYSDEC proposes to use the natural flow regime method (NFRM) for all regions by means of permit conditions. However, NYSDEC should verify the accuracy for the proposed methods for estimating passby flows at ungauged sites. Since NFRM is proposed to be applied everywhere (and not just in a specific case which would justify its use as a permit condition), it would be more appropriate for NYSDEC to include the use of the NFRM as a requirement in the regulations themselves. The following changes should be accounted for in the regulatory framework regarding the avoidance or reduction of potential impacts resulting from water withdrawal:

- NYSDEC should coordinate water withdrawals among operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.
- The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.
- Passby flows should be maintained with consideration of the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating

flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.

3.11 Stormwater, Sedimentation and Erosion

All of the comments summarized in this section are covered in greater detail in the Meliora Design, LLC report (Attachment 6).

3.11.1 Cumulative Water Quality Impacts of Land Disturbance Are Not Addressed

The RDSGEIS provides only a very brief generic discussion of the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the original draft of the GEIS nearly twenty years ago, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts on water quality in the most general and generic manner, with little industry specific consideration, and no consideration of total or cumulative impacts. A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential to a full environmental impact analysis, and to any determinations by NYSDEC on the appropriate regulatory permitting requirements.

3.11.2 Stream Crossing Impacts Are Not Addressed

The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft State Pollutant Discharge Elimination System (SPDES) General Permit. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current NYSDEC regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. NYSDEC should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed requirements to regulate and mitigate these impacts.

3.11.3 Mitigation and SPDES General Permit Do Not Consider Existing Water Quality

With the exception of watersheds that have received Filtration Avoidance Determinations, the RDSGEIS (and associated Draft SPDES HVHF General Permit) do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support the adequacy of the proposed setbacks to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep slopes), and the setbacks

discussed in the narrative of Chapter 7 are not clearly coordinated with EAF requirements in Appendices 4, 5, 6 and 10 and the Draft HVHF General Permit mapping and documentation requirements (and the Draft SPDES HVHF General Permit is presumably the regulatory mechanism for compliance). NYSDEC should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.

3.11.4 SPDES General Permit Flawed

The Draft SPDES General Permit for HVHF is essentially a compilation of the NYSDEC's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. It is not clear from the RDSGEIS's very limited discussion of land disturbance and surface water impacts that a general permit process is sufficient to protect water quality. It is also not clear that an industry that is not subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF. Finally, the general permit process does not provide a timeframe (or process) for public review, comment, and objection to any or all parts of proposed general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the NYSDEC and meeting minimum performance requirements. The SPDES HVHF General permit should provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site before general permit coverage is granted. The permit coverage timeline should be adjusted to provide for public comment and appeal.

3.12 Hazardous and Contaminated Materials Management

All of the comments summarized in this section are covered in greater detail in the Harvey Consulting, LLC report (Attachment 1) and the report of Dr. Glenn Miller (Attachment 3).

3.12.1 Disposal of Waste and Equipment Containing NORM

Naturally Occurring Radioactive Materials (NORM) can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

The RDSGEIS fails to establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved relative to the 2009 DSGEIS in that it establishes radioactive limitations and testing in some cases, but testing is

still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g., for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

3.12.2 Drilling Mud Composition and Disposal

Drilling muds may contain mercury, metals, Naturally Occurring Radioactive Materials (NORM), oils and other contaminates. The NYSDEC appropriately removed the statement that "*drilling muds are not considered to be polluting fluids"* from the proposed regulations in response to this working group's 2009 comments. This positive change is commendable, but there are two problems related to the regulation of drilling muds that remain:

- The RDSGEIS states that the vertical portion of wells would be "typically" drilled using compressed air or freshwater mud as the drilling fluid. There is no regulatory restriction on industry using toxic additives in drilling mud, with corresponding increases in the risks of water resources contamination during drilling, transport and disposal. NYSDEC should stipulate in the regulations the mandatory use of compressed air or freshwater mud and prohibit the use oil-based muds, synthetic-based muds and the use of toxic additives.
- The proposed regulations do not provide criteria for acceptable drilling mud disposal plans to ensure safe handling and disposal. The proposed regulations should require specific best practices for drilling mud handling and disposal.

3.12.3 Reserve Pit Use and Drill Cuttings Disposal

The RDSGEIS acknowledges the numerous environmental advantages of a closed loop tank system to manage drilling fluids and cuttings rather than reserve pits, but fails to require a closed loop tank system in all circumstances. The closed loop tank system is only required for wells without an acceptable acid rock drainage mitigation plan for onsite disposal and for cuttings that need to be disposed at a landfill because they contain toxic additives. The proposed regulations should prohibit reserve pits and require a closed loop tank system. Reserve pits should only be allowed where the applicant demonstrates that the closed loop tank system would be technically infeasible. The proposed regulations also should include testing of the shale to determine the extent of potentially acid generating material included in the cutting.

The RDSGEIS states that onsite disposal of water-based muds is permissible, despite the fact that these muds may contain mercury, metals and other contaminates. These contaminated muds would be put in direct contact with soils and groundwater, resulting in the potential for significant adverse environmental impacts not addressed in the RDSGEIS. Some portions of the RDSGEIS and proposed regulations vaguely reference a requirement for consultation with the NYSDEC Division of Materials Management prior to disposal of cuttings from water-based mud drilling, but this "consultation" improperly circumvents the proper public review that would be provided by reaching a decision on the disposal requirements for water-based mud and associated cuttings through the environmental review process.

3.12.4 Hydraulic Fracture Additive Limitations

The RDSGEIS and proposed regulations continue to rely solely on the drilling operators to (1) regulate themselves, and (2) select the lowest toxicity chemicals for use in fracture treatment additives.

The proposed regulations require documentation that the additives exhibit "reduced aquatic toxicity" and "lower risk to water resources" compared to alternate additives or documentation that alternatives are not equally effective or feasible. There are no specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk. Operators would still be allowed to use harmful chemicals merely by stating to NYSDEC that these are the only chemicals that would be "effective" or by showing that the chemicals they propose are slightly less toxic than the most toxic alternatives.

To address this problem, the RDSGEIS and proposed regulations should identify the type, volume and concentrations of fracture treatment additives that are protective of human health and the environment; include a list of prohibited additives; and require the use of non-toxic materials to the greatest extent possible.
NYSDEC should develop the list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the New York State Department of Health (NYSDOH) has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the RDSGEIS as a mitigation measure and codified in the proposed regulations.

3.12.5 Centralized Surface Impoundments for HVHF Flowback Off-Drillsite

The 2009 DSGEIS disclosed significant adverse air quality impacts associated with centralized surface impoundments for HVHF flowback, which were found to emit over 32.5 tons of air toxics per year. However, this important impact information was removed from the RDSGEIS. Instead, NYSDEC improperly declined to analyze centralized surface impoundments based on statements by the industry that they would not "routinely propose" to use centralized flowback impoundments. The proposed regulations do not prohibit centralized surface impoundments, which would be appropriate

mitigation for the significant adverse impact identified in the 2009 DSGEIS, and instead a separate site-specific SEQRA review would be required for them.

3.12.6 Chemical and Waste Tank Secondary Containment

NYSDEC appropriately codified a requirement for secondary containment for chemical and waste handling tanks in the proposed regulations. However, the proposed regulations do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment. The regulations should be revised to address secondary containment for transport, mixing and pumping equipment in order to minimize potential soil and water resource impacts from chemical spills. There are several other minor modifications to the proposed regulations for secondary containment detailed in Chapter 21 of the Harvey Consulting, LLC report (Attachment 1) to eliminate inconsistencies between various regulatory requirements.

3.12.7 Fuel Tank Containment

NYSDEC appropriately included a requirement for fuel tank secondary containment in the Proposed Supplementary Permit Conditions. However, this requirement is confused by inconsistent statements in the RDSGEIS that secondary containment is not required for *temporary* fuel tanks (page 7-34). In addition to correcting this inconsistency, the proposed regulatory framework for fuel tank containment should be substantively improved to be more protective of the environment through adoption of the following changes:

- Define clear criteria for adequate containment (e.g., using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area).
- Include mandatory minimum setbacks from surface water features, homes and public buildings. The proposed regulations contain a setback for surface water resources, but only “to the extent practical.”
- Explain how NYSDEC’s requirements for fuel tank containment interface with federal requirements (40 CFR Part 112).
- Require tank inspections, spill prevention and spill alarm systems.
- Clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed in cases where secondary containment is impractical, and codify the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

3.13 Toxicology

This section addresses the toxicology-related issues associated with Naturally Occurring Radioactive Materials (NORM), hydraulic fracturing additives and waste disposal. For supporting technical information for these comments, refer to the technical reports of Dr. Glenn Miller (Attachment 3) and Dr. Ralph Seiler (Attachment 4).

3.13.1 Naturally Occurring Radioactive Materials

The Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations. The primary environmental contamination risk associated with NORM is in production brines. Appendix 13 of the RDSGEIS presented some information on radioactivity

characteristics of vertical wells in the Marcellus Shale in New York. However, the data in Appendix 13 identifies only 14-24% of the gross alpha radiation sources in the water samples. The sources of the other 75%+ of alpha radiation are not identified. The RDSGEIS explicitly acknowledges that the scientific understanding of NORM in production brine is incomplete.[6] NYSDEC should have obtained more information on the radiation sources in production brine as part of the SGEIS process because it is essential to NYSDEC's decision-making process and for NYSDEC to ensure that adequate regulations are in place before widespread HVHF occurs in New York. Even if the information could not have been reasonably obtained (which is not the case here), the proper approach for SEQRA compliance would have been to disclose the unavailable information in accordance with NYCRR §617.9 (b) (6)[7]:

One possible source of the unspecified alpha levels in production brines is polonium. Polonium-210 is 5,000 times more radioactive than radium and is highly toxic.[8] Polonium-210 is difficult and expensive to remove from drinking water and bioaccumulates in the environment. Before completing the SEQRA process, NYSDEC should determine if polonium is a significant component of alpha emission in formation waters and identify appropriate regulations that address polonium-contaminated wastewater to prevent water resource impacts. Specific technical recommendations regarding the analyses that should be conducted to determine the presence of polonium are provided in Attachment 4. Attachment 4 also addresses the potential for Polonium-210 exposure via build-up in natural gas delivery pipes.

3.13.2 Radon Exposure via Natural Gas Combustion

Radon is a cancer-causing, radioactive gas. Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. The quantity of radon in natural gas is highly variable and has not been studied by NYSDEC in the Marcellus Shale. While normal natural gas use in properly ventilated burners are unlikely to contribute to radon concentrations in a closed space, poorly vented areas may well be a problem, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners) need to be subjected to risk assessment. At the very least, substantially more radon measurements need to be made. The risk is likely to be greatest in those areas that already have elevated radon in air, and that risk may be enhanced by the natural gas contribution. Any increase in radon exposure in the Southern Tier is of particular concern in terms of cumulative impacts given that the NYSDOH estimates the majority of homes in

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[6] 2011 RDSGEIS Page 5-142: "The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options…."

[7] *In addition to the analysis of significant adverse impacts required in subparagraph 617.9(b) (5) (iii) of this section, if information about reasonably foreseeable catastrophic impacts to the environment is unavailable because the cost to obtain it is exorbitant, or the means to obtain it are unknown, or there is uncertainty about its validity, and such information is essential to an agency's SEQR findings, the EIS must:*

(i) identify the nature and relevance of unavailable or uncertain information;
(ii) provide a summary of existing credible scientific evidence, if available; and
(iii) assess the likelihood of occurrence, even if the probability of occurrence is low, and the consequences of the potential impact, using theoretical approaches or research methods generally accepted in the scientific community.

This analysis would likely occur in the review of such actions as an oil supertanker port, a liquid propane gas/liquid natural gas facility, or the siting of a hazardous waste treatment facility. It does not apply in the review of such actions as shopping malls, residential subdivisions or office facilities.

[8] http://www.who.int/ionizing_radiation/pub_meet/polonium210/en/index.html

the region have existing basement radon levels above the EPA "action level" of 4 pCi/L. Between 20 and 40 percent of homes in the several Marcellus Shale counties have long-term exposure to radon levels above the EPA limit in their living areas.[9] Before completing the SEQRA process, NYSDEC should analyze the cumulative health risk posed by additional radon exposure from Marcellus Shale natural gas combustion so that appropriate mitigation measures can be identified to address the issue.

3.13.3 Hydraulic Fracturing Additives

The RDSGEIS does not present sufficient information to analyze the toxicology risks posed by hydraulic fracturing additives. It does not address the toxicology risks generically or at the site level. The proposed regulations do not require permit applicants to provide sufficient information for the risks of these additives to be considered at the site level. The RDSGEIS provides a long list of potential additives (Tables 5.4 and 5.5), but does not analyze their potential environmental impacts. The list of additives is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives nor the amounts in which they would be used during the HVHF process there is no basis for estimating the risk of these components with regard to their presence in the produced flowback or produced water.

The RDSGEIS misrepresents the presence of hydraulic fracturing additives in flowback. Table 6.1 of the RDSGEIS states that no non-naturally occurring additives were detected. However, most of these additives cannot be detected through standard methods. Table 6.1 should be revised to indicate which additives were actually capable of being detected by the analytical methods selected and the associated detection limits. This is a customary practice and standard. The proposed regulations should require testing of flowback water for acrylonitrile, a non-naturally occurring chemical that if detected provides a clear indication of off-site contamination by hydraulic fracturing.

3.13.4 Disposal of Contaminated Wastewater

The water that flows back immediately following hydraulic fracturing is heavily contaminated, primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The produced brines that are released during production generally have higher concentrations of naturally occurring contaminants than flowback waster (although lower volumes) and similarly represent a serious chemical contamination potential. Four problematic components of the flowback water and produced brines are present: the radioactive component (NORM); the inorganic salts, metals and metalloids; the organic substances (from the hydrocarbon formation) and the hydraulic fracturing additives. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS. Reuse is not a

[9] http://www.wadsworth.org/radon/

complete disposal option because residual salts and other contaminants must still be managed. Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells, municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water) and private treatment plants (of which none currently exist in New York). The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with these disposal options.

3.14 Air Quality and Odors

For supporting technical information for the comments provided in this section, refer to Chapters 17 and 20 of the Harvey Consulting, LLC report (Attachment 1).

3.14.1 Air Quality Modeling Assumptions

The air quality analysis in the RDSGEIS contains some substantial improvements compared to the DSGEIS, but the assumptions used still warrant additional review and justification. For example, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. In addition, the mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal). Limitations used in the modeling assumptions must all be translated into SGEIS mitigation measures and codified in the proposed regulations to ensure that the National Ambient Air Quality Standards will not be exceeded.

3.14.2 Air Quality Monitoring Program

The RDSGEIS includes a commitment to develop a regional air quality monitoring program to address the potential for significant adverse air quality impacts. However, more information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

3.14.3 Greenhouse Gas Emissions Mitigation Plan

The RDSGEIS took a step in the right direction with the inclusion of a requirement for greenhouse gas emissions (GHG) impact mitigation plans. However, this requirement needs to be further defined. NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions

reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions. The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs. The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.4 Flare and Venting of Gas Emissions

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. During production operations, 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. Reducing gas flaring and venting is widely considered best practice for reducing air quality impacts of natural gas development. The RDSGEIS air quality analyses of flaring assumed it would be limited to three days based on statements from industry, even though the actual duration should be longer. Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting restrictions should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.5 Reduced Emission Completions

Reduced Emission Completions (RECs, also known as "green completions") control methane and other GHG emissions following HVHF operations. RECs also reduce nitrogen oxide (NOx) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere. The RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of wellsites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale. Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a

mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.6 Gas Dehydrators

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. Gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions. The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement. In addition to this requirement, natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.7 Diesel Engine Emissions Control

NRDC's 2009 comments recommended limiting diesel engines to Tier 2 or higher. The RDSGEIS takes a step in the right direction by prohibiting "Tier 0" engines and requiring Tier 2 engines in most cases. To further strengthen air quality protection from diesel emissions SGEIS should examine whether it is possible to eliminate Tier 1 engine use altogether.

3.14.8 Leak Detection and Control

Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs. NYSDEC's proposed Leak Detection and Repair Program should be revised to require: a drillsite Leak Detection and Repair inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the proposed regulations, and be required for all natural gas operations, not just HVHF operations.

3.14.9 Cleaner Power and Fuel Supply Options

The RDSGEIS did not examine cleaner power and fuel supply options as was requested in NRDC's 2009 comments. In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where highline power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. These requirements should apply to all natural gas operations, not just HVHF operations.

3.14.10 Hydrogen Sulfide (H_2S) ("Sour Gas") Emissions

In addition to air quality risks associated with emissions of criteria pollutants and air toxics resulting from natural gas development, additional air quality risks can occur as a result of the release of hydrogen sulfide (H_2S) or sour gas. H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause very serious health symptoms, and can be deadly at the higher concentrations found in some oil and gas wells.

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public. The RDSGEIS does not analyze H_2S impacts based on the argument (supported by limited evidence) that to date H_2S has not been detected in high concentrations in HVHF operations in Pennsylvania. However, the early experience in Pennsylvania does not mean that there is no potential for H_2S issues to develop over time in New York.

A supplemental permit condition proposed in the RDSGEIS appropriately requires monitoring for H_2S during the drilling phase. However, a requirement should be added to the HVHF regulations to ensure that periodic monitoring occurs throughout production as gas fields age and sour. H_2S monitoring requirements should apply to all wells and therefore should be addressed through regulations, rather than through permit conditions that can be altered without public review. The regulations should stipulate that when monitoring detects H_2S, nearby neighbors, local authorities and public facilities should be notified of the risk of H_2S gas. They should be provided information on safety and control measures that the operator will be required to undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

3.15 Socioeconomics

This section addresses the socioeconomic impacts of HVHF. For supporting technical information for these comments, refer to the technical report from Dr. Susan Christopherson (Attachment 5).

3.15.1 NYSDEC's Socioeconomic Impact Analysis

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. There are a number of substantive concerns raised by the discussion of socioeconomic impacts presented in the RDSGEIS and by the Economic Assessment Report (EAR) prepared by NYSDEC's consultant, Environment and Ecology, on which that discussion is based.

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used in the RDSGEIS to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a "ramp-up" period and then proceeding through a regular pattern of well development over time. This model is misleading, and because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model cannot appropriately assess those impacts.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required, along with an estimate of how costs will increase and accumulate as development expands.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur.

3.15.2 Uncertainty and Volatility of Natural Gas Production and its Socioeconomic Impacts

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the commercially extractable gas from any particular well is uncertain. This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, they may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies. The model used in the RDSGEIS to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this unlikely gradual, regular development scenario, raising doubts about the projection of economic benefits based on that model.

The spatial distribution of impacts is also uneven. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have implications for social and economic impacts. If drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape (as was modeled in the RDSGEIS), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic <u>costs</u> of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry.

Contrary to the RDSGEIS' contention that the regularized development model "does not significantly affect the socioeconomic analysis," smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies.

3.15.3 Economic Impact Study Fails to Address Costs

The 2011 RDSGEIS analyzes potential *economic benefits* of HVHF, but fails to provide the same level of analysis of the potential *costs* of HVHF. A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF.

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt.

(2) Costs to the state that will reduce or offset tax revenues are not calculated.

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the RDSGEIS, including public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., as well as costs associated with monitoring and inspection and infrastructure maintenance. Although experience in other shale gas plays demonstrates that these costs are likely, the RDSGEIS makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment.

(4) There is no analysis of the expected 2-3 year lag between immediate costs and anticipated revenues, during which communities will be faced with significant public service costs.

Given the inability of the EAR input-output model to address the costs of gas development and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

3.15.4 Impacts on Other Industries

HVHF has the potential to have significant adverse effects on the viability of other industries in New York, particularly tourism and agriculture. In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine

state investments intended to support those industries. Given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

3.15.5 Housing and Property Value Impacts

The potential impacts of HVHF on the housing supply, housing costs, and housing financing are inadequately addressed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis. However, given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing. This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either or temporarily or permanently, the value of this new housing is likely to plummet. The social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed. These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% reduction in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus, "…residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights." (EAR, 4-114). The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values. A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

3.15.6 Effects on Employment

The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells.

In contrast, nearly 674,000 New York jobs were sustained by tourism activity last year, representing

7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010. In the Southern Tier alone, the tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in 2008. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue.

The RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals.

In addition, many of the highest paid jobs associated with HVHF will not be filled locally. Occupational employment statistics geographical analysis of petroleum engineers, one of the most common occupations in the oil and gas industry, indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. This data suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs in petroleum engineering.

The creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is also likely to occur <u>outside</u> the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process. Although the EAR asserts that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs.

3.15.7 Regional Plan of Development Approach to Mitigating Socioeconomic Impacts

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions. Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur enables local government to anticipate and develop strategies to mitigate cumulative impacts. The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal,

pipeline construction) in the area to be affected. A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

To further assist communities in planning for socioeconomic impacts, a series of reporting requirements should be incorporated into the RDSGEIS and regulations. As development activities begin and progress, the information provided in initial projections should be confirmed or revised on a semiannual basis. This information is critical to forecasting and meeting housing and service demands.

In addition, mitigation strategies need to be developed and described in the RDSGEIS that address long term costs to affected regions and the impacts of the resource depletion phase of the exploration, drilling, and development process, when population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Finally, mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

3.16 Traffic and Transportation

While the RDSGEIS improves upon the 2009 DSGEIS regarding estimates truck trip generation, the impact of HVHF on roadway congestion and safety has not been adequately addressed in the RDSGEIS.

The impacts of a typical multi-well development on congestion and safety should be analyzed in detail; such analysis should include a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related economic activity.

The LBG technical memo (Attachment 7) details the specific analyses that should be undertaken and describes how the transportation mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable. The transportation plan requirement in the RDSGEIS is a good first step, but additional detail is needed on the transportation plan including required contents, methodologies and impact criteria to make this mitigation measure meaningful.

3.17 Noise and Vibration

The construction and operation phase noise impact assessments presented in RDSGEIS are improved over the 2009 DSGEIS, but still contain important flaws that understate the impacts.

For example, the drilling and fracturing impact assessment presented is for one well, ignoring the cumulative impact of multiple wells being developed at the same time. Even using the analysis for a single well, the sound levels associated with the fracturing process are so extreme that hearing damage could result from exposure for 8-hours at a distance of 500 feet from the well pad.

Transportation-related noise impacts are not quantified in the RDSGEIS. Potential noise effects on wildlife are not evaluated, even though the noise of a single well and even more so the combination of noise of multiple wells could affect wildlife (especially sensitive bird species). The cumulative

effects of noise on wildlife habitat and fragmentation effects of almost continual disturbance are not evaluated.

Vibration impacts and low-frequency noise impacts (which are associated with health impacts) are similarly not addressed in the RDSGEIS. The LBG technical memo details the specific analyses that should be undertaken and describes how the noise mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable.

Similar to the transportation plan requirement mentioned above, the noise mitigation plan requirement lacks specificity regarding the analyses required and the thresholds that trigger the need for mitigation. A best practice template for NYSDEC to consider adopting to specify the requirements for noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38).

3.18 Visual Resources

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. This assessment should incorporate best practices for analyzing visual impacts, such as identifying the relevant view groups, landscape zones and photo simulations of well development in various contexts.

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present *and* within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not state designated significant visual resources are present. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.19 Land Use

The RDSGEIS fails to provide any analysis of the reasonably foreseeable cumulative land use impacts that would result if HVHF development goes forward in New York. This should be corrected by providing information on existing land use patterns and analyzing the impact of the level of development anticipated in the economic impact study on land use change. The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.20 Community Character

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources,

historic resources, socioeconomics, traffic, and noise.[10] The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how HVHF would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each). A complete community character impact assessment is needed (including regional cumulative impacts) to ensure appropriate mitigation measures are included in the HVHF regulatory framework.

3.21 Cultural Resources

In addition to the ecological effects of the massive ground disturbance and industrial development that will occur with HVHF in New York, the integrity of historic architectural resources, archaeological sites and culturally significant areas to Native Americans is also threatened. The RDSGEIS does not address comments provided by New York Archaeological Council during scoping in 2008 on cultural resource issues and does not adequately address this important resource topic. There is no section of the RDSGEIS specifically devoted to the direct, indirect and cumulative impacts of HVHF on cultural resource or any discussion of mitigation measures (except for impacts related to visual resources). The reliance on the 1992 GEIS for protection of cultural resources is not sufficient given the significantly different type and scale of impacts that could occur with HVHF and the length of time that passed since the 1992 GEIS was prepared. The role of the New York State Office of Parks, Recreation and Historic Preservation (OPRHP) in the review of individual permit applications is not clear in the RDSGEIS. In addition, the RDSGEIS does not explained how tribal consultation regarding impacts to cultural resources will be accomplished in a manner consistent with NYSDEC's own 2009 policy *Contact, Cooperation, and Consultation with Indian Nations*. Cultural resource impacts, mitigation measures and project-level review requirements must be addressed before HVHF is approved. Refer to the LBG technical memorandum for more information supporting these comments (Attachment 7).

3.22 Ecosystems and Wildlife

The ecological effects of HVHF and related infrastructure development include direct losses of habitat, fragmentation of existing habitats and indirect "edge effects" such as the spread of invasive species and noise disturbance of wildlife. The RDSGEIS qualitatively acknowledges these impacts and summarizes the findings of studies conducted in other locations, but does not provide build-out analyses that could quantify the range of cumulative habitat loss and fragmentation effects in New York. As evidenced by The Nature Conservancy's build-out analysis of Tioga County, such an analysis is readily achievable with existing GIS tools and datasets available to NYSDEC.[11] The RDSGEIS should include quantitative build-out analysis of habitat fragmentation and edge effects using estimates of development potential consistent with those developed for the RDSGEIS economic impact assessment and include the impacts from reasonably foreseeable infrastructure such as pipelines and compressor stations. Based on the results of the build-out analysis, NYSDEC should also analyze the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

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[10] New York City Mayor's Office of Environmental Coordination. 2010. City Environmental Review Technical Manual.
[11] The Nature Conservancy. 2011 . "An Assessment of the Potential Impacts of High Volume Hydraulic Fracturing on Forest Resources."

The RDSGEIS characterizes the ecological impacts of HVHF as “unavoidable” and fails to consider alternative mitigation approaches that could lessen significant adverse environmental impacts. The site-specific ecological assessments and mitigation measures required by the RDSGEIS for well pads in grasslands greater than 30 acres and forest patches greater than 150 acres is a fragmented approach. It does not address the importance of landscape connectivity between habitat patches, which is essential to the movement and long-term viability of numerous species. A preferable methodology would be to set limits on deforestation, fragmentation and increases in impervious surface cover based upon ecological planning units such as the sub watershed. The SGEIS process should consider an alternative where rather than the current spacing unit requirements (which are intended to maximize production), land disturbance would be restricted region wide based on ecological carrying capacity. An ecologically oriented planning framework could significantly lessen the adverse impacts of HVHF development on terrestrial and aquatic systems.

In addition, consideration should be given to cumulative changes to land use within each watershed that could lead to detrimental changes in the affected stream to support critical species habitat. Limiting the percent increase in impervious area to less than five percent (inclusive of existing uses) in trout supporting watersheds, including upstream tributaries, would reduce the potential for adverse impacts to sensitive aquatic organisms and the loss of a waters best use designation.

The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline right-of-ways and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is not restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not “restoration”. It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

For supporting technical information for these comments and additional comments on ecological impacts and mitigation measures, refer to the technical report from Kevin Heatley (Attachment 8) and LBG (Attachment 7).

3.23 Climate Change

The RDSGEIS ignores the real possibility that climate change impacts will undermine the safety of HVHF operations, frustrate mitigation efforts proposed by NYSDEC, and therefore exacerbate adverse impacts to the environment and human health resulting from HVHF operations. Increases in extreme weather events, such as floods, pose considerable obstacles to the safety of HVHF operations and infrastructure in and around low-lying coastal areas and floodplains. Precipitation changes coupled with enormous surface and groundwater withdrawals may result in modified groundwater flow patterns, which may cause unexpected groundwater contamination that jeopardizes drinking water supplies. Increased temperatures can volatilize dangerous chemical compounds at drill sites, exposing workers and nearby residents to airborne carcinogens at a rate greater than would be expected by modeling baseline temperatures without climate change. Remarkably, the effect of climate change on the availability of water resources is ignored in the section on the cumulative impact of water withdrawals, and no provision is made for situations where HVHF operations and public needs may conflict over water usage. Underscoring these concerns is the notable failure of NYSDEC to conduct a comprehensive Health Impact Assessment, despite the real possibility that climate change impacts confluent with HVHF operations can pose serious human

health problems. Reliable reports on the effect of climate change on New York abound, including some produced within the last year by New York governmental bodies. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which may pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

For supporting technical information regarding these comments, refer to the technical report from Dr. Kim Knowlton (Attachment 9).

3.24 Health Impact Assessment

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, and while the RDSGEIS addresses some aspects of a subset of these health issues, it fails to address other important health risks. The RDSGEIS not only omits several issues, but also it only addresses only some aspects of other issues such as air, water quality, and heightened traffic without fully considering health impacts in those areas. Lastly, it doesn't consider health issues as a group in a formal Health Impact Assessment (HIA), including interactive effects on the health of local residents and communities. A full HIA as part of the RDSGEIS is a necessary component, as there are already numerous reports of health complaints including dizziness, sinus disorders, depression, anxiety, difficulty concentrating, and many others, among people who live near natural gas drilling and fracturing operations in other states. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

For supporting technical information regarding these comments, refer to the technical report from Dr. Gina Solomon (Attachment 10).

3.25 Induced Seismicity

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments. The justification provided is that high volume hydraulic fracturing is not expected to cause induced seismicity that will result in adverse impacts. Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. The RSDGEIS assumes that operators will manage seismic risks voluntarily and makes statements regarding the frequency of use of seismic monitoring techniques that are internally contradictory. It also fails to recognize the potential significance of unmapped faults and relies too heavily on the occurrence of natural seismicity as a future predictor of the potential for induced seismicity. Finally, it underestimates the potential adverse consequences of induced seismicity, which include risks to drinking water, well integrity, private and public property, and New York City drinking water supply infrastructure. The RSDGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary. The RSDGEIS must require operators to evaluate and manage the risk of induced seismicity from hydraulic fracturing through proper site characterization and hydraulic fracture treatment design.

For supporting technical information regarding these comments, refer to the technical report from Briana Mordick (Attachment 11).

Attachment 1

Harvey Consulting, LLC.

2011 NYS RDSGEIS

Revised 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 and

Proposed Revisions to the New York Code of Rules and Regulations

Best Technology and Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

January 9, 2011

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Appendix B – Intermediate Casing Table
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1. Introduction

This report responds to the Natural Resources Defense Council's (NRDC), and its partner organizations Earthjustice, Inc., Riverkeeper, Inc., Catksill Mountainkeeper and Delaware Riverkeeper Network, request for a review of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) 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 and proposed revisions to the New York Code of Rules and Regulations (NYCRR).

NRDC, and its partners, requested a technical review of the RDSGEIS and the proposed revisions to the NYCRR to determine if best technology and practices were included. NRDC has also commissioned additional experts; therefore, this list of recommendations is not exhaustive and is complementary to the work assigned to other experts. A complete list of expert recommendations can be found in the summary cover letter submitted by The Louis Berger Group, Inc., on behalf of NRDC, to the New York State Department of Environmental Conservation (NYSDEC) during the RDSGEIS public comment period.

This report makes recommendations for improving the SGEIS and the proposed revisions to the NYCRR. Overall, HCLLC found that NYSDEC made a number of significant improvements in both the RDSGEIS and the proposed revisions to the NYCRR. HCLLC commends NYSDEC for integrating a number of new best practices and technology alternatives into its 2011 RDSGEIS and proposed regulations.

This report highlights the RDSGEIS areas of improvement and reinforces the importance of retaining those improvements in the final SGEIS and the proposed NYCRR revisions. However, there remain significant areas for improvement. This report provides additional technical justification and scientific support for best practices and technology that warrant further NYSDEC consideration. It also recommends area of further study. Recommendations are highlighted in blue text boxes throughout the document.

A systemic problem persists in the 2011 RDSGEIS, where NYSDEC 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 without addressing the fact that the technology and practices required by the 1992 GEIS are over two decades old.

Since 1992, numerous best technology and best management practice improvements have been made in the oil and gas industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS' RDSGEIS starts with an unstable foundation. This problem is magnified in the proposed revisions to the NYCRR where NYSDEC proposes to retain, with little revision, antiquated technology and practices for all oil and gas development in NYS, while proposing that new technology and practices only apply to HVHF operations. This creates a technically and scientifically unsupported two-tiered system for oil and gas regulation in NYS.

Accordingly, the first and most logical step in the State Environmental Quality Review Act (SEQRA) analysis is to examine the 1992 GEIS foundation and identify new best technology and best practice improvements have been made since 1992 that warrant adoption. 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.

2. Scope of SGEIS – Marcellus Only

Background: In 2009, NYSDEC proposed that the SGEIS cover all horizontal drilling and HVHF in low-permeability gas reservoirs, at all depths. However, only the Marcellus Shale Gas Reservoir was studied in any detail. The DSGEIS was incomplete for all other low-permeability gas reservoirs.

In 2009, HCLLC recommended that NYSDEC either include additional information and analysis on the impacts of exploring and developing other low-permeability gas reservoirs or limit the scope of the SGEIS to the Marcellus Shale Gas Reservoir.

NYSDEC's consultant, Alpha Geoscience, disagreed with HCLLC's recommendation to limit the SGEIS scope to the Marcellus Shale, stating that the time to modify the scope had lapsed.[1] Alpha Geoscience concluded that it would be best for NYSDEC to determine at a future date, once a specific application was before them, whether the SGEIS covered High-Volume Hydraulic Fracturing (HVHF) operations in other low-permeability reservoirs.

HCLLC disagrees with Alpha Geoscience's recommendation, because it lacks technical and scientific basis and misconstrues HCLLC's recommendation. HCLLC did not recommend that other low-permeability gas reservoirs be excluded from the analysis because they should not be studied at all. On the contrary, HCCLC recommended that if low-permeability gas reservoirs were included in the SGEIS, they should be thoroughly studied. The 2009 DSGEIS should have included a complete assessment of the Marcellus **and** all other low-permeability gas reservoirs in NYS; however, it did not. Unfortunately, the 2011 RDSGEIS suffers from the same lack of data on other low-permeability gas reservoirs.

Consequently, there is a technical and scientific choice that needs to be made in declaring whether the SGEIS content satisfies its title. Either the SGEIS had to be revised to cover all low-permeability gas formations in NYS, or the SGEIS had to conclude that NYSDEC has insufficient data and/or resources to examine anything more than the Marcellus Shale at this time, and limit the scope of the SGEIS.

HCLLC's 2009 recommendation was made to ensure the SGEIS document title matches its content. The title of the SGEIS purports to provide an environmental impact analysis on all low-permeability gas reservoirs, yet, as explained in HCLLC's 2009 comments, the SGEIS did not provide sufficient analysis of the Utica Shale, and provided no analysis of the other Lower Paleozoic, Devonian (other than Marcellus), and Middle to Upper Paleozoic low-permeability gas reservoirs.[2,3] If NYSDEC has additional information to support a complete SGEIS for the Marcellus **and** all other low-permeability gas reservoirs, it should certainly include that complete assessment.

Unfortunately, the 2011 RDSGEIS suffers from the same narrow focus on the Marcellus shale. There was little additional work completed to advance NYSDEC's understanding of exploration and development impacts from the Utica Shale and other low-permeability gas reservoirs.

[1] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 3.

[2] Ryder, R.T., 2008, Assessment of Appalachian Basin Oil and Gas Resources: Utica-Lower Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2008–1287.

[3] Milici, R.C., and Swezey, C.S., 2006, Assessment of Appalachian Basin Oil and Gas Resources: Devonian Shale-Middle and Upper Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2006-1237.

2011 RDSGEIS: The 2011 RDSGEIS provides some additional information on the Utica Shale Gas Reservoir, mostly in the form of geologic assessment. However, the RDSGEIS does not examine the peak or cumulative impacts of Utica Shale development.

No additional information is provided in the 2011 RDSGEIS on other low-permeability gas reservoirs in the region. The 2011 RDSGEIS states that industry's main focus in the near term is the Marcellus and Utica Shales; however, NYSDEC wants to cover all other low-permeability formations in the SGEIS because it may receive applications in the future for those formations:

> *The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production…**Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing** [emphasis added].* [4]

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are studied. Yet, it is well known that most unconventional reservoirs vary in mineralogy, permeability, rock mechanics, and natural fracture parameters (length, orthogonal spacing, connectivity, anisotropy) and that there will be differences between formations that could lead to different drilling, stimulation, and development techniques.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. 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.

A search of the 1537 page electronic version of the RDSGEIS for the term "low-permeability gas reservoirs" shows that the term is only used a few times in the entire document. This term is used twice in the Executive Summary, where NYSDEC concludes that it has effectively studied "low-permeability gas reservoir" air quality impacts; yet, as further explained in Chapter 17 of this report there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence of the term "low-permeability gas reservoirs" is not found until page 618 in the Air Quality Section, where again, NYSDEC states that it has included the impacts of "low-permeability gas reservoirs" in the air quality analysis; yet, there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence, after the Air Quality Section, is found at page 1008, where NYSDEC defends exclusion of pipeline and compressor stations. A few minor references to this term are found at page 1071 in Chapter 9 (Alternative Actions). More simply put, the RDSGEIS contents do not match the title, and that there is insufficient information contained in the RDGSEIS to support development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS. NYS has not developed a technical or scientific case to justify that the impacts described for the Marcellus Shale are representative of the peak or cumulative impact that would result from development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS.

The 2011 RDSGEIS does not include a complete list of the formation names that it considers fit under the umbrella term of "low-permeability" formations. The only place that the term "low-permeability" formation is defined is in the Glossary at the end of the document:

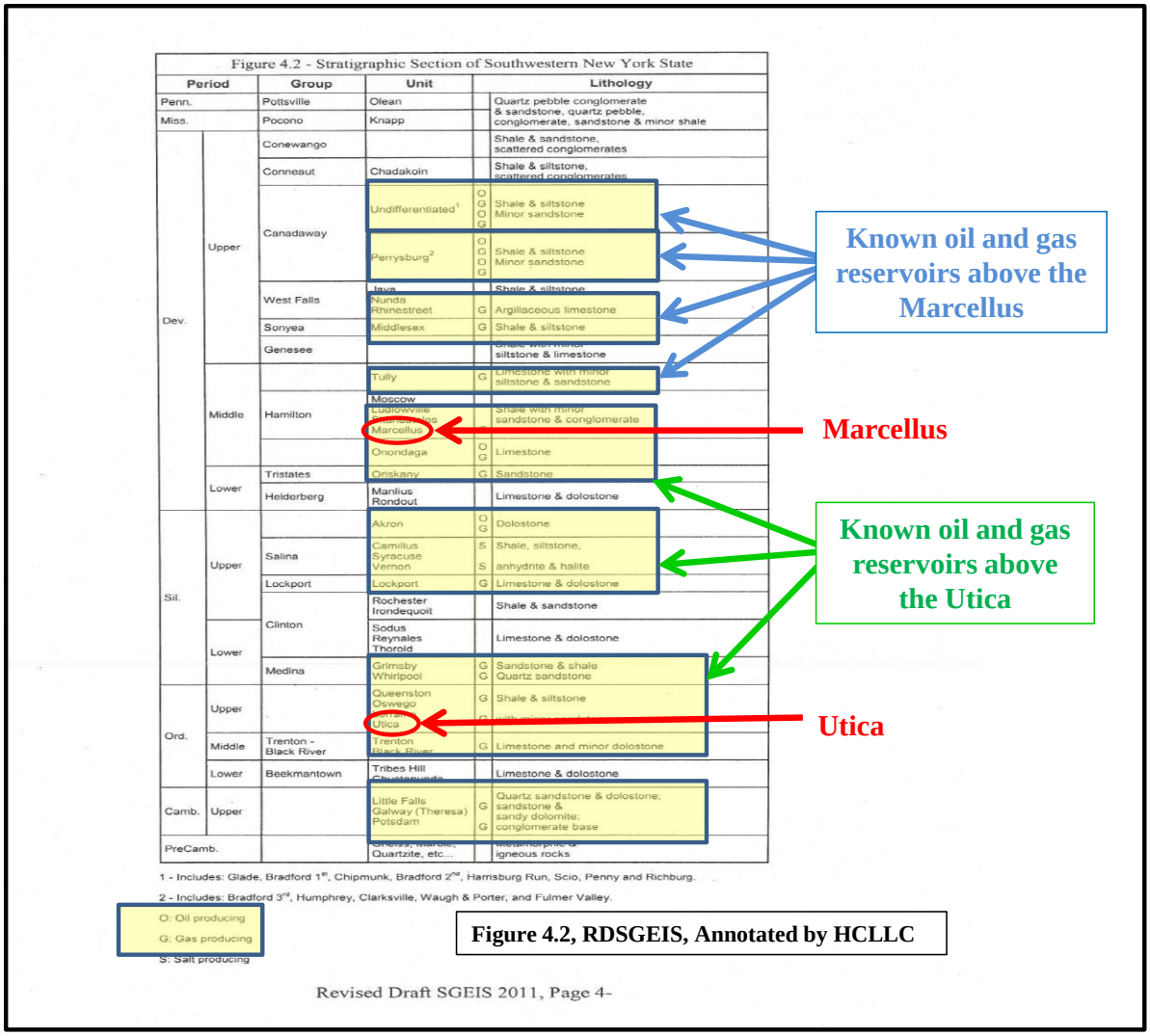
> *Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 milidarcies.*[5]

[4] 2011 NYSDEC, RDSGEIS, Page 1-1.

[5] 2011 NYSDEC, RDSGEIS, Glossary.

Using this definition, a low-permeability formation could include a shale, sandstone, limestone or other formation that is gas bearing with a permeability of less than 0.10 milidarcies. The RDSGEIS does not address the scope of the formations that could be encompassed by this definition.

Figure 4.2 of the RDSGEIS[6] includes a stratigraphic section showing existing known oil and gas intervals above the Marcellus and Utica Shales, including numerous shale and other low-permeability formations that are known to exist, that were not examined in the SGEIS.



On the next page is a table summarizing historical oil and gas production data from 1967 to 2010 in NYS.[7] This table shows that there is numerous gas zones present both above and below the Marcellus Shale that have been producing gas. Some of these reservoirs are low-permeability reservoirs that may be further developed using horizontal drilling and hydraulic fracturing techniques. Additionally, this table shows that there has been no Utica Shale production in NYS from 1967 to 2010; therefore, little is known about its productivity or how it may be developed.

[6] 2011 NYSDEC, RDSGEIS, Page 4-7.

[7] NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011, using NYS data found at http://www.dec.ny.gov/energy/1601.html. 1967-1999 data came from summary production history files. 2000-2010 data came from oil and gas production files.

NYS Oil & Gas Data Summary 1967-2010

		Formation	Oil (bbl)	Gas (mcf)		Oil (bbl)	Gas (mcf)
Devonian	Upper	DEVONIAN SHALE	12,274	323,975			
		UPPER DEVONIAN	364,054	881,848	DEVONIAN SHALE	376,328	1,208,697
		UPPER DEVONIAN SHALE	-	2,874			
		Canadaway Undifferentiated					
		GLADE	1,392,255	449,124			
		BRADFORD	7,665,427	1,639,511			
		BRADFORD 1ST & 2ND	21	-			
		BRADFORD & CHIPMUNK	416,357	676,506			
		Bradford 1st & Chipmunk	6,609	2,497			
		CHIPMUNK, BRADFORD 1ST & 2ND	44,943	10,217			
		CHIPMUNK	7,369,293	1,012,975			
		CHIPMUNK & BRADFORD 2ND	2,454,948	16,415			
		BRADFORD SECOND	21,724	2,520			
		CHIPMUNK, BRADFORD 2ND & 3RD	237,195	162,809	CANADAWAY UNDIFFERENTIATED	23,945,472	7,271,139
		Chipmunk, Bradford 1st,2nd,3rd	9,719	8,321			
		BRADFORD 2ND & 3RD	37,780	9,353			
		CHIPMUNK & BRADFORD 3RD	33,186	34,858			
		Chipmunk & Harrisburg	2,442	1,026			
		Harrisburg	1,682	-			
		SCIO	137,258	2,520			
		PENNY	13,232	46,567			
		PENNY & FULMER VALLEY	42,660	71,003			
		RICHBURG	4,057,637	3,121,677			
		RICHBURG-WAUGH & PORTER	1,104	3,240			
		Canadaway PERRYSBURG	-	395			
		BRADFORD THIRD	228,582	112,002			
		CLARKSVILLE	39,387	36,864	PERRYSBURG	2,055,287	4,746,392
		WAUGH & PORTER	42,100	247,245			
		FULMER VALLEY	1,745,218	4,349,886			
		Nunda	-	-			
		RHINESTREET	-	3,409			
	Middle	TULLY	1,108	275,643	TULLY	1,108	275,643
		HAMILTON	-	20,416	HAMILTON	-	20,416
		MARCELLUS	-	747,399	MARCELLUS	-	747,399
		ONONDAGA	647,251	25,843,114	ONONDAGA	647,251	25,843,114
		ONONDAGA-ORISKANY	-	223,157			
	Lower	ORISKANY	10,582	31,738,725	ORISKANY	10,582	31,961,882
		HELDERBERG	-	10,230,425	HELDERBERG	-	10,230,425
		ONONDAGA-BASS ISLAND	532,310	3,118,389			
Silurian	Upper	BASS ISLAND	1,021,802	5,739,620	BASS ISLAND	1,580,509	9,416,091
		BASS ISLAND/MEDINA	26,397	558,082			
		AKRON	1,577	1,729,358	AKRON	1,577	1,729,358
		SALINA	1,278	5,778			
		CAMILLUS	-	60			
		SYRACUSE	570	2,338			
		VERNON	-	358,405			
		CLINTON	-	87,231			
		LOCKPORT	-	69,528			
		ROCHESTER SHALE	-	70,693			
		SAUQUOIT	-	210			
	Lower	SODUS SHALE	-	164,071			
		MEDINA	213,688	514,545,705			
		GRIMSBY	-	1,501,854	MEDINA	213,688	521,205,687
		WHIRLPOOL	-	893,326			
		MEDINA-QUEENSTON	-	4,264,802			
		HERKIMER	-	5,849,567			
		HERKIMER-ONEIDA	-	1,178,375			
		ONEIDA	-	1,024,647	HERKIMER-ONEIDA-OSWEGO	-	9,169,025
		ONEIDA-OSWEGO	-	1,094,384			
Ordovician	Upper	QUEENSTON	-	56,439,648	QUEENSTON	-	56,439,648
		OSWEGO	-	22,052			
		UTICA	-	-			
	Middle	TRENTON	-	485,477	TRENTON	-	485,477
		BLACK RIVER	-	318,316,063	BLACK RIVER	-	318,316,063
Cambrian	Upper	LITTLE FALLS	-	501,440	LITTLE FALLS	-	501,440
		THERESA	-	3,588,222	THERESA	-	3,588,222
		POTSDAM	-	-			

NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011.

Using the Marcellus Shale impact assessment and proposed mitigation measures as a surrogate for peak and cumulative impact assessment in the Utica and all other unnamed low-permeability formations is an inadequate approach.

For example, the Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir. The Utica Shale dips to 9,000' deep,[8] while the Marcellus Shale is approximately 5,000' deep.[9] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste, HVHF waste and resulting in longer duration surface impacts (e.g. noise, light, fuel and chemical storage periods, etc.). Additionally, waste generated translates into additional transportation and surface use impacts. Utica Shale development will also require more resources and equipment. Deeper shale gas formations will have higher reservoir pressure, and will penetrate more known oil and gas zones before reaching the Utica Shale, meaning increased blowout risk. Higher reservoir pressure will require additional combustion equipment to meet higher pump pressure and energy demands. Deeper wells can have more complex well construction designs. Fully cemented casing strings will be more difficult to complete at deeper depths and higher temperature cement mixtures will be required if subsurface temperatures exceed 200 ^{0}F. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact of a Utica Shale well.

Additionally, there is little information in Petroleum Engineering technical literature on the Utica Shale, and how it may be effectively developed. The 2011 RDSGEIS assumes that the Utica Shale will be developed using the same exact techniques as the Marcellus Shale; however, this may not be the case. For example, a 2007 a paper prepared by Universal Well Services Inc., CESI Chemical A Flotek Industries Co., in collaboration with the State University of New York noted some significant differences in the Utica Shale, and the likelihood for a unique stimulation method:

> *The primary purpose of stimulating fractured shale reservoirs is the extension of the drainage radius via creation of a long fracture sand pack that interconnects with natural fractures thereby establishing a flow channel network to the wellbore.* ***<u>However, there is limited understanding of a successful method capable of stimulating Utica Shale reservoirs. Indeed most attempts to data have yielded undesirable results</u>****. This could be due to several factors, including formation composition, entry pressure, and premature pad fluid leak-off. Furthermore, stimulation of Utica shale reservoirs with acid alone has not been successful. This treatment method leads to a fracture length and drainage radius less than expected resulting in poor well productivity [emphasis added].*[10]
>
> *…several recently drilled Utica shale wells have not responded well to the normal shale fracturing practices.* ***<u>An understanding of Utica shale mineralogy and rock mechanics is necessary before a stimulation method and fluid are selected</u>*** *[emphasis added].*[11]

Additionally, the authors point out that the Utica, unlike the Marcellus, contains a high percentage of acid soluble carbonate and dolomite that may require chemical treatment (e.g. acids) to treat the carbonates and dolomite to reduce entry pressures. They suggest that an acid stimulation treatment could potentially be the main stimulation method instead of a HVHF, or alternatively be added as an additional pre-

[8] 2009 NYSDEC, DSGEIS, Page 4-5.

[9] 2009 NYSDEC, DSGEIS, Page 4-14.

[10] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 1.

[11] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 2.

treatment to a HVHF. The Utica also contains a higher percentage of clays than the Marcellus, and has the potential to generate both siliceous and organic fines that may require additional chemical treatment.

Moreover, there are low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale, which were not studied at all. Those unnamed, unanalyzed low-permeability reservoirs are in closer proximity to protected water resources, and warrant a complete technical and scientific assessment. Most importantly, HVHF modeling and fracture design requirements should be established to ensure that man-made induced fractures in these shallower reservoirs do not propagate in a manner that pollutes protected groundwater resources. Man-made induced fractures in shallower formations will tend to propagate on the horizontal plane; however, the size of that horizontal fracture must be constrained so that it does not intersect with existing improperly constructed or improperly abandoned wells or transmissive faults and fractures that can provide a direct pollution pathway to protected groundwater resources.

Best technology and best practices and cumulative impacts, in many cases, are reservoir specific. Because the RDSGEIS does not contain information on the depth, type, activity, or equipment requirements for the general category 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 best practices developed for the Marcellus Shale would apply to the Utica Shale since there is very little information and understanding of the optimal Utica Shale stimulation method at this time.

Recommendation No. 1: The SGEIS should either include additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the SGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

3. Liquid Hydrocarbon Impacts (Oil and Condensate)

Background: NYS 2009 Annual Oil and Gas Report[12] show that NYS produced 323,536 barrels of oil in 2009, primarily from the western counties of:

Cattaraugus	201,688 barrels
Allegany	47,421 barrels
Chautauqua	40,187 barrels
Steuben	9,992 barrels

NYSDEC did not separately report the amount of condensate or natural gas liquids production.

Chapter 2 of this report includes a table summarizing oil and gas production from 1967 to 2010 in NYS, showing that oil gas been produced from above the Marcellus and Utica Shale formations, verifying the potential to encounter liquid hydrocarbons while drilling into the Marcellus and Utica formations.

2011 RDSGEIS: The 2011 RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drillsites may be needed to develop those oil resources.

Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. [13] Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.[14,15]

The 2011 RDSGEIS provided several useful maps and a stratigraphic section that aid in understanding the overlap of NYS' oil and gas production intervals. Figure 4.2 includes a Stratigraphic Section of Southwestern NYS that shows oil is produced from the Upper Devonian, at shallower depths than the Marcellus Shale, meaning that wells drilled in this region may encounter oil before penetrating the Marcellus. An annotated version of Figure 4.2 is also shown in Chapter 2 of this report. Figures 4.8 and 4.9 indicate that there is an overlap of current oil production with possible Marcellus Shale development in Cattaraugus, Allegany, Chautauqua, and Steuben counties.

Oil is also found below the Marcellus Shale and above the Utica Shale in the Upper Silurian. Therefore wells drilled into the Utica Shale may encounter oil before penetrating the Utica. Figure 4.6 indicates that there is an overlap of current oil production with possible Utica Shale development in Steuben County.

[12] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009.

[13] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[14] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

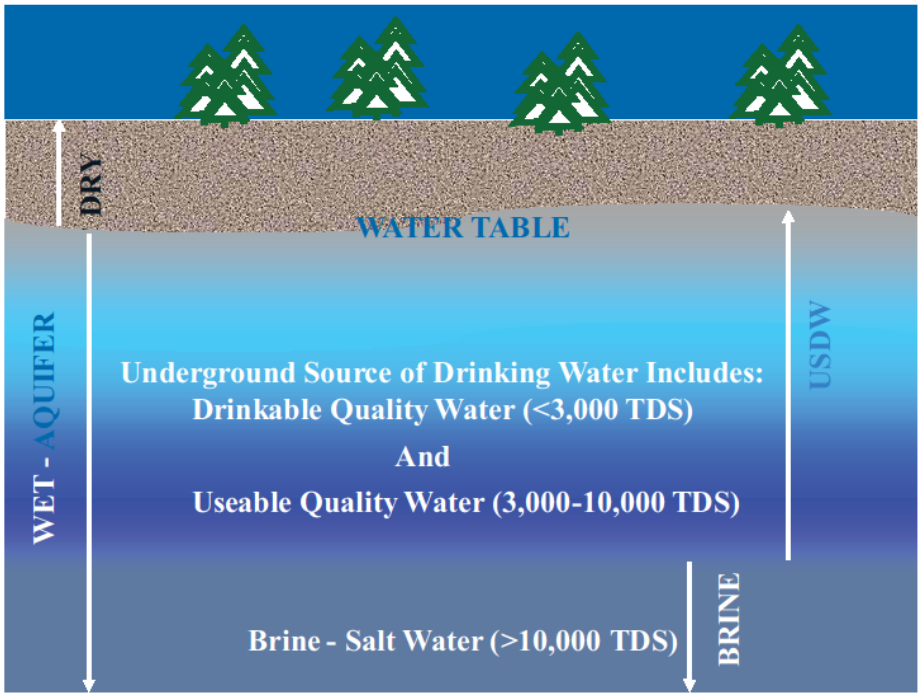
[15] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

There are low-permeability gas reservoirs that are present at depths both shallower and deeper than the Marcellus Shale, which were not studied in detail in the RDSGEIS. Absent geologic maps for these unnamed, unanalyzed low-permeability reservoirs, it is not clear where oil development and shale gas development overlap for these reservoirs may occur.

Recommendation No. 2: The SGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The SGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drillsites that may be required to develop oil resources identified by shale gas exploration and production activities.

4. Water Protection Threshold

Background: The regulations promulgated under the federal Safe Drinking Water Act (SDWA) define an Underground Source of Drinking Water (USDW) as an aquifer or part of an aquifer, which is not exempted (per 40 CFR § 146.4), and: (1) which supplies a public water system; or (2) which contains a sufficient quantity of groundwater to supply a public water system and either supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of Total Dissolved Solids (TDS) [10,000 ppm TDS]. 40 CFR § 144.3. An EPA diagram depicting a USDW is shown below.[16]



The 2011 RDSGEIS: The 2011 RDSGEIS is based on the protection of potable water as defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS. The RDSGEIS states:

> *For oil and gas regulatory purposes, **potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS** and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS [emphasis added].*[17]

The RDSGEIS identifies 850' as the depth where 250 ppm of sodium chloride or 1,000 ppm TDS is typically reached, however the RDSGEIS notes that in some cases potable water is found deeper than 850'.

[16] USEPA, Karen Johnson, Chief Ground Water & Enforcement Branch, 2010 PowerPoint Presentation, EPA's Underground Injection Control Program, Regulation of Disposal Wells in Pennsylvania.

[17] 2011 NYSDEC, RDSGEIS, Page 2-23.

> ***Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water*** *and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data [emphasis added].*[18]

By comparison, USDWs are based on a TDS cutoff of 10,000 ppm. The RDSGEIS has not explained why it proposes, and NYS regulations rely on, a 1,000 ppm TDS threshold instead of the federally required USDW threshold of 10,000 ppm TDS.

Ohio issued updated Oil and Gas Well Construction Rules on October 28, 2011, that require surface casing and intermediate casing to be set to protect the deepest underground source of drinking water (USDW); Ohio's rules are based on the 10,000 ppm federal TDS threshold.[19]

Recommendation No. 3: The SGEIS and the NYCRR should require wells to be constructed to protect Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act.

NYS' use of a 1,000 ppm TDS cut-off instead of the USDW threshold of 10,000 ppm TSD is a two-fold problem: First, the RDSGEIS states that surface casing ("water protection piping") setting depths will be 925' if no other data is available.[20] The 925' surface casing setting depth is based on an 850' base plus 75'[21], where NYSDEC has assumed that TDS will exceed 1,000 ppm at deeper than 850'. The 925' casing setting depth does not take into account the fact that drinking water, under the SDWA definition of a USDW, could exist at depths below 850'. Therefore the RDSGEIS has not provided scientific justification for the default 925' casing setting depth, nor has it explained how such a proposal comports with federal law.

Second, the entire RDSGEIS is premised on the conclusion that a HVHF well initiated at a depth of 2,000' would be safe, because NYSDEC assumes that NYS does not have any drinking water resources deeper than 850' deep. However, the RDSGEIS does not indicate that any examination of the depth of 10,000 ppm TDS water or of the availability of drinking water resources below 850' has been or will be conducted and, therefore, cannot support its 850' assumption.

Additionally, the RDSGEIS states that potable water is found deeper than 850'. Therefore, the 2,000' threshold depth for initiating a HVHF under this SGEIS requires re-evaluation. And as explained in Chapter 10 of this report, HCLLC is recommending that initial drilling and completions occur below 4,000', while site-specific data is gathered in NYS to justify safe drilling at shallower depths.

[18] 2011 NYSDEC, RDSGEIS, Page 2-23.

[19] Proposed Ohio Oil and Gas Well Construction Rules, October 28, 2011, currently under public review and comment.

[20] 2011 NYSDEC, RDSGEIS, Page 7-50.

[21] See Chapter 6 of this report, where a 100' buffer is recommended, instead of 75'.

Recommendation No. 4: The SGEIS should re-examine the 925' casing default setting and the 2000' HVHF cut-off, and justify how these proposed thresholds will protect USDW sources. Protecting to a 10,000 ppm TDS standard will likely increase both depths.

The SGEIS should include data on the location of Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act, across NYS. The SGEIS should include USDW maps for all areas that will be affected by the proposed scope of the SGEIS. This data will be an important tool for industry and the public alike to ensure USDWs are protected.

NYCRR Proposed Revisions: Well construction regulations at 6 NYCRR § 550-559 instruct operators to construct oil and gas wells in a manner that protects potable fresh water, i.e., only water containing less than 250 ppm of sodium chloride or less than 1,000 ppm of TDS. 6 NYCRR § 550.3 (ai).

The NYCRR does not protect, under its definition of "potable fresh water," water resources with less than 10,000 ppm TDS but greater than 1,000 ppm TDS, which could qualify as USDWs under the Safe Drinking Water Act. See 40 CFR §§ 144.3, 146.4.

Regulations at 6 NYCRR § 554.1 require operators to prevent pollution to "surface or ground fresh water"; however, this term is not defined by the NYCRR, so it is unclear what additional groundwater beyond "potable fresh water" would be protected or how.

Recommendation No. 5: The NYCRR should be consistent with federal law [Underground Sources of Drinking Water (USDWs)] or NYSDEC should propose more protective standards for NYS if needed to protect NYS' future water supply needs, if the federal threshold is found insufficient.

5. Conductor Casing

Background: In 2009, HCLLC recommended the NYCRR and the SGEIS be revised to include conductor casing construction standards. While a number of changes were made to improve conduct casing requirements in the RDSGEIS, the proposed revisions to the NYCRR do not include conductor casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on conductor casing and the technical basis for HCLCC's recommendations.

Conductor casing construction standards are only partially addressed in the 2011 RDSGEIS, under Appendix 10, Proposed Supplementary Permit Conditions for HVHF, and Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers**.**

2011 RDSGEIS: The 2011 RDSGEIS Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, includes a conductor casing requirement that limits drilling fluid types. The requirement excludes synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*

Excluding synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore is a best practice.

Appendix 9 also includes procedures for ensuring conductor pipe is cemented from top to bottom, and firmly affixed in a central location in the wellbore, with a continuous, equally thick layer of cement around the pipe.

> *If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results.*
>
> *Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*

The 2011 RDSGEIS Appendix 10, Proposed Supplementary Permit Conditions for HVHF, includes a conductor casing condition that states:

> *When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.*

NYCRR Proposed Revisions: In summary, NYSDEC has included important conductor casing construction guidelines in the 2011 RDSGEIS for wells drilled in primary and principal aquifer areas and HVHF wells, but has not proposed to codify those changes in the NYCRR.

The conductor casing construction guidelines listed in the 2011 RDSGEIS should apply to all wells in NYS, and should not just be limited to wells drilled in primary and principal aquifer areas and HVHF wells. These are best practices for construction of all oil and gas wells.

NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide solid structural anchorage. Also, the regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

Recommendation No. 6: Conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the NYCRR and should apply to all wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

6. Surface Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional surface casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on surface casing the technical basis for HCLCC's recommendations.

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well.

The drilling engineer determines the depth of surface casing installation with these key factors in mind: surface casing should stop above any significant pressure or hydrocarbon zone, ensuring the blowout preventer can be installed prior to drilling into a pressure or hydrocarbon zone, and surface casing should provide a protective barrier to prevent hydrocarbons from contaminating aquifers when the well is drilled deeper (below the surface casing) into hydrocarbon bearing zones.

Stray gas may impact ground water and surface water from poor well construction practices. Properly constructed and operated oil and gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion.

Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania.[22] Gas well leaks from improperly constructed gas wells have resulted in contamination of the Susquehanna River and adjacent private water supply wells.[23] A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. Duke University found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[24]

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for surface casing. Overall, NYS' surface casing requirements are fairly robust when the NYCRR, guidance documents, and standard stipulations are combined. NYSDEC proposed a number of substantial improvements in the surface casing requirements, most notably improved cement quality, casing quality, and installation techniques.

This chapter reviews the proposed changes and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and adds a few additional recommendations for NYSDEC to consider in completing its surface casing regulatory program revision.

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[22] *See, e.g.*, DEP Reaches Agreement with Cabot to Prevent Gas Migration, Restore Water Supplies in Dimock Township, Agreement Requires DEP Approval for Well Casing, Cementing, November 4, 2009, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/14287?id=2418& typeid=1.

[23] *See, e.g.*, DEP Monitors Stray Gas Remediation in Bradford County Requires Chesapeake to Eliminate Gas Migration, Chesapeake Commits to Evaluate, Remediate All PA Wells to Conform with Improved Casing Regulations, September 17, 2010, available at http://www.portal.state.pa.us/portal/server.pt/ community/newsroom/14287?id=14274&typeid=1.

[24] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane contamination of drinking water accompanying gas- well drilling and hydraulic fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, Page 2.

The main recommendation in this section is to streamline surface casing regulations by amending the NYCRR to include requirements contained in the 2011 RDSGEIS and standard stipulations. As proposed, NYSDEC has included a number of surface casing requirements in the 2011 RDSGEIS at Appendices 8, 9, and 10 (Proposed Permit Conditions). NYSDEC also included some, but not all, of these requirements in the NYCRR. Unfortunately, there are a number of inconsistencies between the permit conditions and the NYCRR that create uncertainty about what will be required.

Additionally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in NYCRR Part 560 (drilling practices for HVHF wells).

In 2009, HCLLC recommended that improved casing and cementing practices be codified in the NYCRR, rather than through a combined patchwork of permit conditions and regulations. HCLLC's concern was that the proposed requirements, in a number of cases, were inconsistent with existing regulations, and could be more efficiently consolidated into a single, more concise set of regulations.

NYSDEC's consultant Alpha Geoscience disagreed. Alpha Geoscience concluded that it would be more logical to use a patchwork of regulations, add a long list of conditions to each permit, and forgo regulatory revision.

> *Harvey Consulting suggests that NYSDEC revise the NYS oil and gas regulations to specifically address new casing and cementing practices and fresh water aquifer supplementary permit conditions. The purpose of the SGEIS, however, is not to revise regulations. The purpose of the Proposed Supplementary Permit Conditions for shale gas activities is to customize the existing regulations and guideline framework to fit new and changing industry, relieving the need for frequent regulatory changes. Permit conditions must be met by the party seeking a permit for a proposed action, so whether or not the permit conditions are included in the New York State regulations is irrelevant.*[25]

HCLLC disagrees with Alpha Geoscience's recommendation. It is relevant whether new requirements are found in regulation or a permit condition. Foremost, revising the outdated NYCRR provides simplicity and clarity for industry and the public. It provides a concise set of co-located rules. Conversely, layering a complex patchwork of permit conditions on outdated NYCRR creates confusion, inconsistency, and enforcement challenges. Furthermore, permit conditions can be revised and modified by staff, without public review, and can be applied in a more discretionary manner. Regulations are not discretionary, and are not subject to modification without a formal public review process. Therefore, HCLLC recommends that requirements that apply to all wells be codified in the NYCRR, and permit conditions be reserved for site-specific, project-specific requirements. This will improve clarity and certainty for industry and the public alike, and will afford NYSDEC the opportunity to apply site-specific, project specific requirements to address unique project issues.

NYSDEC evidently agreed with HCLLC's recommendation to revise the NYCRR by proposing revisions for public review; however, the regulations have only been partially updated to include new surface casing best practices. Therefore inconsistency remains, and needs resolution.

Recommendation No. 7: The surface casing and cementing requirements should be consistent throughout the SGEIS text and with the NYCRR.

[25] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 13.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below and compared to the proposed NYCRR revisions. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: It appears that NYSDEC's intent is to require that all wells meet the minimum standards found at Appendix 8 (NYSDEC's Casing and Cementing Practices), and then layer on additional requirements for wells drilled in primary and principal aquifers (Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers). It appears that a third layer of requirements will be applied to wells that undergo HVHF stimulation treatments (Appendix 10 Proposed Supplementary Permit Conditions for HVHF).

Therefore, it is assumed that a shale gas well that is drilled in a primary and principal aquifer, and will undergo a HVHF stimulation treatment must meet all the conditions found in Appendices 8, 9, and 10; however, this would not be possible because the permit conditions are discordant. An evaluation of these layered conditions reveals inconsistencies, as explained in the text and summary table below.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires: surface casing be set at least 75' below freshwater or at least 75' into bedrock, whichever is deeper; surface casing be set before hydrocarbons are encountered; new pipe be used (or used pipe if tested); and centralizers and cement baskets be used.

> 2. *Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP [blow-out preventer] stack to contain any formation pressures that may be encountered before the next casing is run.*
>
> 3. *Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).*
>
> 4. *All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.*
>
> 5. *Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.*[26]

Appendix 8 requires the use of: 25% excess cement, spacer fluids between the drilling muds and cement, and lost circulation additives. Appendix 8 also requires that gas flows or lost circulation be addressed and

[26] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 1.

the hole be conditioned before cementing. NYSDEC reserves the right to require a cement evaluation log if cement does not return to the surface.

> 6. *Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.*
>
> 7. *The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.*[27]

Appendix 8 requires: the water used in the cement be tested for pH and temperature; the cement be prepared according to manufacturer specifications; and the cement be allowed to harden to a compressive strength of at least 500 psi before being disturbed.

> 8. *The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.*
>
> 9. *The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.*
>
> 10. *After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.*[28]

The 2011 RDSGEIS Appendix 9: Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, applies to wells drilled in primary and principal aquifer zones. Appendix 9 includes conditions that require: surface casing to be set at least 100' below the deepest freshwater zone and at least 100' into bedrock; the annulus be at least 1-1/4" wide to optimize cement placement and cement sheath width: the entire annulus be cemented, using at least 50% excess cement; the cement design include additives to control lost circulation; centralizers be run at least every 120'; new pipe be used (or reconditioned tested pipe); and NYSDEC be notified and present for cementing operations.

[27] 2011 NYSDEC, RDSGEIS, Appendix 8, Pages 1-2.

[28] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

> *A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*[29]

Appendix 9 requires the surface hole be drilled using compressed air or Water-Based Muds (WBM), meaning no Synthetic-Based Muds (SBM) or Oil-Based Muds (OBM) may be used.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*[30]

As found in Appendix 9, freshwater zone depths and the potential for shallow gas hazards must be estimated and documented in drilling applications; actual data must be collected during drilling to identify any freshwater zones and shallow gas hazards that require additional NYSDEC review and approval.

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.* [31]

Appendix 9 requires cement fill the surface casing annulus, and if cement placement in the annulus is not initially successful, additional cement must be pumped into the annulus until it is filled with cement.

> *In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in*

[29] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[30] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[31] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

> *combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations.* [32]

In Appendix 9, NYSDEC reserves the right to require the operator to run a cement bond log; however, it does not require one to verify the integrity of all surface casing cement jobs.

> *This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.*[33]

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional surface casing requirements. The 2011 RDSGEIS does not explain why these additional pollution prevention and quality control/quality assurance (QC/QA) requirements do not apply to all oil and gas wells in NYS.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[34]

[32] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[33] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[34] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

Appendix 10 also requires: drilling mud be circulated and conditioned prior to cementing; spacer fluid be used to separate the drilling mud from the cement, to avoid drilling mud contamination; and cement be installed using methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond… The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned.*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[35]

Appendix 10 establishes a specific period of time for the cement to harden, and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> > *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
> >
> > *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[36]

Appendix 10 requires records be kept for a period of 5 years and be available to NYSDEC upon request.

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[37]

[35] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[36] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[37] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 reserves the right for NYSDEC to require additional casing strings to be set in the well if the surface casing fails to adequately protect water resources or poses a safety hazard.

> *38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.*[38]

Appendix 10 requires NYSDEC's Casing and Cementing Practices be followed. NYSDEC's Casing and Cementing Practices are included in the 2011 RDSGEIS as Appendix 8. Yet, a number of the Casing and Cementing Practices found in Appendix 8 conflict with the new requirements in Appendix 10 for wells subject to HVHF.

The RDSGEIS does not provide a rationale or basis for the use of a 75' surface casing setting depth for some wells and a 100' surface casing setting depth for others. NYSDEC determined that a 100' setting depth is best practice for groundwater protection in areas of primary and principal aquifers, but does not explain why a 100' standard would not be best practice for all wells, or at least wells that undergo HVHF.

An analysis of the surface casing permit condition requirements and inconsistencies is provided in table format as Appendix A. Recommendations are listed in the table.

NYCRR Proposed Revisions: A number of the requirements listed in the RDSGEIS Appendices 8, 9, and 10 are not codified in the NYCRR, or conflict with the proposed changes to the NYCRR.

Listed below is an analysis of the proposed NYCRR revisions for surface casing and cementing. Specific recommendations for improving surface casing design, installation, and quality control/ quality assurance requirements are also included.

Surface Casing Setting Depth: 6 NYCRR § 554.1(d) requires that:

> *Surface casing shall be run in all wells to extend below the deepest potable fresh water level*.

Neither the 75' nor the 100' setting depths below the deepest protected water zone (described in the RDSGEIS) are specified in regulation. Furthermore, this regulation only protects "potable fresh water." As explained in Chapter 4 of this report, NYSDEC should consider its long-term water needs.

> **Recommendation No. 8**: 6 NYCRR § 554.1(d) should be revised to require the surface casing setting depth to be at least 100' below protected groundwater for all wells, or NYSDEC should provide a technical justification for reducing the setting depth to 75' for some wells.

Surface Casing Definition: 6 NYCRR § 550.3(au) reads:

> *Surface casing shall mean casing extending from the surface through the potable fresh water zone*.

This definition requires surface casing be set through only the protected water zone, and does not require the casing be set deeper. This definition, as written, does not include the important requirement for the casing to be set at least 100' below protected groundwater and be cemented in place.

[38] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 8.

Recommendation No. 9: 6 NYCRR § 550.3(au) should be revised to read: surface casing shall mean casing installed and cemented from the surface, through protected groundwater, to a point at least 100' below the deepest protected groundwater. Protected groundwater should be defined in a way that meets NYS' long-term water needs.

Rotary Tool Drilling Practices: 6 NYCRR § 554.4 should be revised to be consistent with the proposed RDSGEIS surface casing conditions, and remove reference errors. 6 NYCRR § 554.4(a) provides the operator with a choice of installing surface casing in accordance with 6 NYCRR § 554.1(b) (which does not provide specific instruction to the operator) or by cementing the production casing from below the deepest potable fresh water level to the surface (which does not provide specific instruction to the operator).

§554.4 Rotary tool drilling practices

(a) On all wells where rotary tools are employed, and the subsurface formations and pressures to be encountered have been reasonably well established by prior drilling experience, the operator shall have the option of either running surface casing as provided in section 554.1(b) of this Part or of cementing the production casing from below the deepest potable fresh water level to the surface. In areas where the subsurface formations and pressures to be encountered are unknown or uncertain, surface casing shall be run as provided in section 554.1(b) of this Part.

6 NYCRR § 554.1(b) does not provide any specific direction on the type or amount of surface casing to be installed; it just says:

Pollution of the land and/or of surface or ground freshwater resulting from exploration or drilling is prohibited.

Nor does 6 NYCRR § 554.4(a) provide any specific direction on the type or amount of surface casing to be installed, other than to say that it must be set below *the deepest potable fresh water level,* but the minimum depth that the casing must be set below the deepest freshwater located is not specified.

Recommendation No. 10: 6 NYCRR § 554.1(d) and 6 NYCRR § 554.4(a) should be combined or at least be consistent to require the surface casing setting depth to be at least 100' below protected groundwater.

NYCRR does not provide the operator with instructions on how to determine protected groundwater depth. The RDSGEIS explains that the depth of potable freshwater in NYS is typically 850' deep, but this depth will vary across the state. Using the 850' benchmark may not sufficiently protect all groundwater covered under the Safe Drinking Water Act. NYCRR should be revised to provide instructions to the operator on how to estimate protected water depth in drilling applications and well construction designs. NYCRR should require that depth be confirmed before setting surface casing.

Recommendation No. 11: NYCRR should require the protected groundwater depth be estimated in the drilling application to aid in well construction design. NYCRR should require the protected water depth be verified with a resistivity log or other sampling method during drilling. If the protected water depth is deeper than estimated, an additional string of intermediate casing should be required. Additionally, the NYCRR needs to be clear on whether its purpose is to protect potable freshwater only, or a broader definition of protected groundwater, which would result in surface casing being set deeper.

6 NYCRR § 554.4(b) correctly requires: cement be placed by the pump and plug or displacement methods; cement be placed in the entire annulus; and a wait on cement time before further drilling. However, 6 NYCRR § 554.4(b) does not include the best practices listed in the permit conditions (Appendices 8 and 9). Additionally, many of the best practices included in Appendix 10 for HVHF wells should be included in regulations for all oil and gas wells.

Recommendation No. 12: 6 NYCRR § 554.4(b) should be revised to be consistent with the proposed Appendices 8 and 9 permit conditions. Also, the best practices listed in Appendix 10 for HVHF should apply to all oil and gas wells and be included in 6 NYCRR § 554.4(b).

Cable Tool Drilling Practices: 6 NYCRR § 554.3 includes requirements for cable tool drilling.

Recommendation No. 13: NYSDEC should verify whether cable tool drilling is still anticipated in NYS. If cable tool drilling is still allowed, 6 NYCRR § 554.3 should be revised to require these wells be constructed to the same quality standards as wells drilled with rotary drilling equipment.

Newly proposed surface casing regulations for HVHF wells at 6 NYCRR § 560.6(c)(10) require casing be run in accordance with the "department's casing and cementing requirements." Presumably this refers to the requirements set out in the RDSGEIS at Appendix 8, but this needs to be clarified. All surface casing requirements for HVHF operations should be codified in NYCRR.

A number of new requirements proposed at 6 NYCRR § 560.6(c)(10) should be applied to all wells in NYS, not just those that will undergo a HVHF treatment. 6 NYCRR § 560.6(c)(10) proposes to add these requirements only to HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

(11) The surface casing must be run and cemented as soon as practicable after the hole has been adequately circulated and conditioned.

The zone of critical cement (e.g. cement placed at bottom of surface casing, typically bottom 300-500') should achieve a 72-hour compressive strength standard of 1,200 psi and the free water separation for the cement should be no more than 6 ml per 250 ml of cement. For example, this requirement is found in the Pennsylvania surface casing code (25 PaCode § 78.85 (b))

An analysis of the proposed Appendices 8, 9, and 10 permit condition requirements and inconsistencies, with comparisons to NYCRR, is provided in table format as Appendix A. Recommendations for improving requirements and addressing inconsistencies are listed in the table.

Recommendation No. 14: The recommendations listed in the Surface Casing Analysis Table (Appendix A to this report) should be considered for the SGEIS and the NYCRR, including:

Surface Casing Setting Depth: NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.

Shallow Gas Hazards: If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

Cement Type: The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

Casing Quality: New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.

Cement Setting Time: Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.

NYS Inspectors: Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

Cement QA/QC: Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.

Formation Integrity Test: It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

BOP Installation: The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[39]

[39] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

7. Intermediate Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional intermediate casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on intermediate casing and the technical basis for HCLCC's recommendations.

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure.

Intermediate casing is set prior to drilling through the hydrocarbon bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe, depending on intermediate casing depth. Intermediate casing provides an additional protective barrier across to prevent contamination of protected groundwater zones.

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for intermediate casing. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. NYSDEC proposed a number of substantial improvements in the intermediate casing requirements. The most notable improvement to the RDSGEIS mitigation and the NYCRR is that intermediate casing will be required in wells that undergo HVHF treatments to provide an additional protective layer of casing and cementing in the well. The RDSGEIS and the NYCRR requires intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools.

However, the remaining area for improvement in the NYCRR is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing. The proposed NYCRR is silent on the intermediate casing and cementing standards for wells that will not undergo HVHF treatment. NYS should provide instruction on intermediate casing standards for all wells that require it.

There are a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new NYCRR Part 560 (drilling practices for HVHF wells).

Recommendation No. 15: The NYCRR should be revised to establish intermediate casing and cementing standards for all wells at NYCRR Part 554 (drilling practices for all oil and gas wells).

This section reviews the proposed changes to intermediate casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS recommends that intermediate casing be required in wells that undergo HVHF treatments, to provide an additional protective layer of casing and cementing in the well. The 2011 RDSGEIS recommends that intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools. This is an excellent recommendation. The 2011 RDSGEIS states:

> *Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis.* ***The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required****. However, the Department may grant an exception to the intermediate casing requirement when technically justified [emphasis added].*[40]
>
> *The current dSGEIS proposes to require in most cases fully cemented intermediate casing, with the setting depths of both surface and intermediate casing determined by site-specific conditions*[41]
>
> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and*[42]
>
> *Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[43]
>
> *Depending on the depth of the well and local geologic conditions, there may be one or more intermediate casing string.*[44]
>
> *Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings.*[45]

The 2011 RDSGEIS proposes a waiver process to exclude intermediate casing under some circumstances:

> *A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.*[46]

[40] 2011 NYSDEC, RDSGEIS, Page 7-52.
[41] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.
[42] 2011 NYSDEC, RDSGEIS, Page 1-12.
[43] 2011 NYSDEC, RDSGEIS, Page 1-12.
[44] 2011 NYSDEC, RDSGEIS, Page 5-92.
[45] 2011 NYSDEC, RDSGEIS, Page 7-42.
[46] 2011 NYSDEC, RDSGEIS, Page 7-52.

The proposed waiver process conflicts with the stated intent of requiring intermediate casing for HVHF wells. The RDSGEIS states that the reason intermediate casing is required for a HVHF well is because it:

> *...directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[47]

As proposed, NYSDEC would consider a wavier if the surface casing is set "deep" or if the well is "shallow"; however, these depths are not defined. The RDSGEIS does not explain how the use of deep-set surface casing or shallow surface casing provides the same protection to aquifers as installing a second string of intermediate casing and cement.

Additionally, as proposed, NYSDEC would consider a wavier if there is an "*absence of fluid and gas in the section between the surface casing and target interval.*[48]" This requirement is incongruous, because there will always be some type of fluid in the formation between the surface casing and target interval; therefore, the conditions for this waiver to occur would never be realized.

Recommendation No. 16: The SGEIS and NYCRR should be revised to remove the waiver provisions for intermediate casing on HVHF wells, or the SGEIS and NYCRR should be revised to include technical justifications, rationale and thresholds for proposed waivers.

The 2011 RDSGEIS requires that intermediate casing be cemented and evaluated for quality as follows:

> *Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice.*[49]
>
> *The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively.*[50]

The requirements for intermediate casing are listed in Appendices 8, 9, and 10 of the RDSGEIS.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires intermediate casing be set only in certain circumstances.

> *Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.*[51]

[47] 2011 NYSDEC, RDSGEIS, Page 1-12.

[48] 2011 NYSDEC, RDSGEIS, Page 7-52.

[49] 2011 NYSDEC, RDSGEIS, Page 7-53.

[50] 2011 NYSDEC, RDSGEIS, Page 7-54.

[51] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers requires intermediate casing be set:

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.*[52]

The main problem with the conditions of Appendices 8 and 9 is that there is no specific guidance for intermediate casing and cementing, if the intermediate casing string is required as part of the well construction design.

Recommendation No. 17: The SGEIS (Appendices 8 and 9) and NYCRR should be revised to provide specific intermediate casing and cementing requirements, as explained further in Appendix B.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional intermediate casing requirements.

The 2011 RDSGEIS Appendix 10 requires intermediate casing be set, unless a waiver is granted:

> *Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*[53]

The 2011 RDSGEIS Appendix 10 requires intermediate casing be completely cemented and the department be notified of cementing operations:

> *This office must be notified _____ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[54]

The 2011 RDSGEIS Appendix 10 requires a cement bond evaluation log:

[52] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[53] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[54] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).*[55]

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[56]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of a spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement; and*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus...*[57]

[55] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[56] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[57] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> > *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
> >
> > *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[58]

Appendix 10 requires records be kept as follows:

> *i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.* [59]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix B. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 do not include specific requirements for intermediate casing, when intermediate casing is part of the well construction design.

A new section of regulations at 6 NYCRR § 560.6(c)(13, 14 and 15) proposes to add intermediate casing requirements for HVHF wells:

> *(13) Intermediate casing must be installed in the well. The setting depth and design of the casing must be determined by taking into account all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may be considered by the department upon a request for a waiver of the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*

[58] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[59] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

(14) As specified on a permit to drill, deepen, plug back and convert, the department must be notified prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25 percent excess cement unless caliper logs are run, in which case 10 percent excess will suffice.

(15) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the intermediate casing. Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

Additional intermediate casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells:

(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:

(i) all casings must be new and conform to industry standards specified in the permit to drill;

(ii) welded connections are prohibited;

(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;

(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;

(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;

(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued

pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to NYCRR is provided in table format in Appendix B. Recommendations for improving requirements are listed in the table.

Recommendation No. 18: The recommendations listed in the Intermediate Casing Analysis Table (Appendix B to this report) should be considered for the SGEIS and the NYCRR, including:

Waiver Provisions: It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.

Setting Depth: Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.

Amount of Cement in Annulus: It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing cannot be fully cemented, most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.

Excess Cement: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the

current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the

well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Pressure Testing: Casing and piping should be pressure tested.[60]

[60] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, Page 109.

8. Production Casing

Background: In 2009, HCLLC recommended NYCRR be revised to include additional production casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on production casing the technical basis for HCLCC's recommendations.

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone, or alternatively sets just above the hydrocarbon zone. Production casing can be run all the way from the surface of the well across the hydrocarbon zone (production casing string) or can be hung from the surface or intermediate casing at a point deeper in the well (production liner).

If production casing is set across the hydrocarbon-producing zone, it is called a "cased hole" completion. In this scenario, production casing is lowered into the hole and cemented in place. Explosives are then lowered inside the production casing (perforation guns) to perforate holes through the pipe/cement barrier to allow oil and/or gas to enter the wellbore. In some cases, a drilling engineer may elect not to set production casing. This is called an "open hole" completion.

NYSDEC recommends a full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place. This is a best practice for HVHF wells.

Production casing is used to isolate hydrocarbon zones and contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The 2011 RDSGEIS and proposed revisions to the NYCRR include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the NYCRR is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and NYCRR requires production casing be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. NYCRR also requires the cement placement and bond be verified by well logging tools. These requirements are best practice.

NYSDEC's proposed HVHF production casing design prevents pollution of protected groundwater by constraining the HVHF pressurized fluid treatment to the inside of the production casing string as it passes the protected groundwater zone. Additionally, behind the production casing string there are two additional layers of casing and cement installed as a barrier across protected waters (e.g. surface and intermediate casing).

This section reviews the proposed changes to production casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS requires that production casing be installed and fully cemented across the production zone in wells that undergo HVHF treatments. The 2011 RDSGEIS states:

> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool.* [61]
>
> *Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.* [62]

The 2011 RDSGEIS Appendix 8: Appendix 8 NYSDEC's Casing and Cementing Practices includes the following production casing requirements for all wells.

12. *The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.*
13. *Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.*
14. *The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.*
15. *The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.*
16. *Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.*[63]

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers does not include any additional requirements for production casing.

[61] 2011 NYSDEC, RDSGEIS, Page 1-12.

[62] 2011 NYSDEC, RDSGEIS, Page 5-92.

[63] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2-3.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional production casing requirements.

The 2011 RDSGEIS Appendix 10 requires production casing run the entire length of the wellbore, which is an excellent recommendation. Appendix 10 also requires production casing be tied into intermediate casing with at least 500' of cement:

> *36) Production casing must be run to the surface. This office must be notified _____ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[64]

Appendix 10 requires a cement bond evaluation log, which is another excellent recommendation:

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*[65]

However, Appendix 10 includes a waiver provision that would exempt an operator from installing production casing cement as described above. This waiver provision is based solely on whether oil and gas might migrate from one pool or stratum to another. It does not address any of the other reasons why production casing cementing is important and required by NYSDEC in HVHF wells.

> *Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval.*
>
> *The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[66]

Recommendation No. 19: The production casing cementing waiver should be removed for HVHF wells, or NYSDEC should provide more technical justification and rationale for the waiver. NYSDEC should show how environmental protection and safety objectives can be achieved to the same level with the waiver as without it.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

[64] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[65] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[66] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

e) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

f) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

g) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

h) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…[67]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

h) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…[68]

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

h) After the cement is pumped, the operator must wait on cement (WOC):

1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and

2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.[69]

[67] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[68] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[69] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 requires records be kept as follows:

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[70]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix C. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 include requirements for production casing:

> *If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing. In such instance, operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.*[71]

A new section of regulations at 6 NYCRR § 560.6(c)(16) proposes to add production casing requirements for HVHF wells.

> *(16) Production casing must be run to the surface. If installation of the intermediate casing is waived by the department, then production casing must be fully cemented to surface.* ***If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth****. Any request to waive any of the cementing requirements of this paragraph must be made in writing with supporting documentation and must be approved by the department. The department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented [emphasis added].*

The proposed regulations at 6 NYCRR § 560.6(c)(16) are inconsistent with the Appendix 10 requirement to cement the production casing with a 500' overlap into the intermediate casing.

> *If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[72]

[70] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[71] 6 NYCRR V.B. §554.4(d)

[72] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

Recommendation No. 20: A production casing 500' cement overlap into the intermediate casing is more protective; 6 NYCRR § 560.6(c)(16) should be revised to match Appendix 10.

A new section of regulations at 6 NYCRR § 560.6(c)(17) requires production casing cement be verified for HVHF wells:

> *(17) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the production casing. Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*

Additional production casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*
>
> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to the NYCRR is provided in table format in Appendix C. Recommendations for improving requirements are listed in the table.

Recommendation No. 21: The recommendations listed in the Production Casing Analysis Table (Appendix C to this report) should be considered for the SGEIS and the NYCRR, including:

Casing Design: For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging, and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.

Centralizers: Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[73]

[73] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

9. Permanent Wellbore Plugging & Abandonment Requirements

Background: In 2009, HCLLC recommended that NYSDEC establish specific criteria to determine when a well must be permanently plugged and abandoned (P&A'd) and recommended improvements in NYS' well plugging regulations, incorporating best technology and practices.

Several terms are used to describe the condition of oil and gas wells that are not active hydrocarbon producers.

- Temporary Abandonment. This term is used to describe a well that may be temporarily suspended as a production well. The well may be shut-in awaiting repairs, a stimulation treatment, workover (e.g. drilling into a new zone) or a decision to finally P&A the well. A reasonable amount time should be afforded to the operator to complete the well work, or to decide when to P&A the well; however, a well should not be temporarily abandoned for a long period of time, because it poses a risk to the environment, especially if the well is known to have a leak or mechanical malfunction. Leaking or malfunctioning wells should be repaired in a timely manner or the well should be permanently P&A'd.

  In 2003, ICF Consulting produced a report for the New York State Energy Research and Development Authority (NYSERDA) that concluded NYS had 5,900 shut-in or temporarily abandoned wells, 39% of the 15,000 known wells.[74] ICF concluded that more than half the 5,900 wells have been "temporarily" abandoned for more than nine years. ICF concluded that:

  > *NYS is one of the few oil and gas producing states that have no specific regulatory provisions for long-term shut-in wells (more than two years). New York's current regulations allow an initial shut in period of one-year and an extension of up to one year, renewable for additional successive periods…*[75]

  ICF concluded that while operators are required to contact NYS to justify temporary abandonment extensions beyond one year, NYS' lack of resources to oversee the program has resulted in many wells remaining idle and not properly P&A'd for years:

  > *The practical effect is that New York's idle well regulation cannot be adequately enforced due to constraints on manpower and other agency resources, and as a result, New York has a defacto long-term inactive well program. For example New York has approximately 1,379 gas wells and 1440 oil wells with either inactive or unknown status that have no reported production since 1992.* [76]

- Permanent Abandonment. A well that is no longer needed to produce hydrocarbons should be plugged (e.g. cement barriers installed, failed casing removed, mechanical plugs set), surface equipment removed (e.g. wellhead and piping), and permanently abandoned. Operators typically do not monitor well condition once a P&A'd job is complete and approved by an agency.

[74] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 1. A final version of this report could not be located on the world-wide web.

[75] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 5.

[76] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 36.

- Improperly Abandoned Well. This term describes a well that was P&A'd, but was done so in a manner where the well still poses a risk to the environment (e.g. insufficient barriers or cement used to seal the well). Because operators typically do not monitor the condition of P&A'd wells, improperly abandoned wells often go un-resolved.

  The problem of improperly abandoned wells in NYS may be a significant issue, because NYS' P&A regulations currently only require 15' cement plugs, which NYSDEC now recognizes as deficient. Therefore, most wells in the state were not P&A'd using a quality standard that would be considered best technology and best practice today.

- Orphaned Well. This term describes a well that was orphaned by the well operator (e.g. insolvent, absentee, or non-responsive well owners) and the well was not P&A'd. Because, by definition, an "orphaned well" does not have an operator to monitor its condition, permanent abandonment of these wells typically becomes a government or property owner responsibility. Given limited agency resources, the magnitude of the environmental hazard posed by any particular orphaned well often is unknown. Unless government or property owners make it a priority to fund well monitoring or plug the well, the potential environmental impacts of orphaned wells cannot be ascertained.

In 2003, ICF Consulting, further examined 4,140 of the long-term inactive wells in NYS and concluded that:

- 546 of the 4,140 wells (13%) were drilled and completed before 1924 (over 87 years old now);
- 1,568 of the 4,140 wells (38%) were drilled and completed from 1924-1964 (at least 47 years old now, and possibly up to 87 years old); and
- 2,026 of the 4,140 wells (49%) had no information on the date of complete or condition.[77]

Therefore, there are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned).

NYS' 2009 Annual Oil and Gas Report[78] shows improperly abandoned and orphaned wells continue to be a significant problem in NYS. NYSDEC reports:

> ***Abandoned, unreported and inactive wells continued to be a problem. In 2009 a total of 450 operators reported 3,043 wells with zero production. This is in addition to over 4,100 orphaned and inactive wells in the Department's records****. Enforcement actions have reduced the number of unreported wells yet some operators refused to file their annual reports. The operators that remained out of compliance have been referred to the Office of General Counsel for additional enforcement actions.[emphasis added]*
>
> *DEC has at least partial records on 40,000 wells, but estimates that over 75,000 oil and gas wells have been drilled in the State since the 1820s.* ***Most of the wells date from before New York established a regulatory program****.* ***Many of these old wells were never properly plugged or were plugged using older techniques that were less reliable and long-lasting than modern methods.*** *[emphasis added]*

[77] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 32.

[78] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009, pp. 22-23.

> *Every year while conducting scheduled inspections or investigating complaints, DEC staff discover more abandoned wells. Extensive courthouse research is often required to identify a well's previous owners. Many of these cases take several years to resolve as DEC pursues legal action against the responsible parties.*
>
> *New York has an Oil and Gas Account which was created to plug problem abandoned wells. It is funded by a $100 per well permit fee; at the end of 2009 the balance was $208,806. DEC has over 500 wells on its priority plugging list. Since* ***the funds are insufficient to plug all the priority wells****, DEC continues to pursue other mechanisms to plug abandoned wells [emphasis added].*

Well construction standards, techniques and technology have improved over time, and it is reasonable to assume that most of these long-term idle wells were not constructed to today's standards, have been subject to mechanical wear and corrosion, and warrant proper abandonment to mitigate risk to protected groundwater resources.

To compound problems, many wells that have not been properly abandoned do not have financial security (e.g. bonds) in place to fund P&A work. ICF reported that, in 2003, NYS had more than 3,500 wells that needed to be P&A'd, but there was no financial security in place (e.g. wells that were grandfathered from NYS bonding requirements). Additionally, ICF reported that 675 of the existing oil and gas wells in NYS have operators that do not comply with the current bonding requirements, and numerous operators that might comply with the existing bonding requirements have plugging liability in amounts that exceed NYS' current bonding requirements, which are too low and do not keep pace with the actual costs of P&A'ing wells today.[79]

The number of temporarily abandoned wells, improperly abandoned wells, and orphaned wells in NYS is a significant issue as shale gas resources are developed, because these old wells could provide a vertical conduit for pollutants to reach protected aquifers. Shale gas wells drilled and fracture stimulated nearby a temporarily abandoned, improperly abandoned, or orphaned well pose a risk. For example, a HVHF treatment can propagate a fracture that, depending on geology, HVHF design, and well depths, could pose a risk of intersection with a nearby well (active producer, abandoned or orphaned well).

Temporarily abandoned wells, improperly abandoned wells, and orphaned wells all pose a risk to the environment. Wellbore infrastructure can corrode and erode, failing over time and creating a potential pollutant pathway for hydrocarbons to move vertically through failed casing or cement to groundwater resources. These wells can either leak gas on their own or provide a vertical pollutant pathway to groundwater resources that can be activated by new well activity nearby.

In 2009, HCLLC recommended that temporary abandonment be limited to no longer than a one-year period, with a wellbore integrity monitoring requirement to ensure that the well is not leaking during temporary abandonment, and a requirement to permanently abandon the well after it is idle for more than a year. HCLLC recommended that NYSDEC carefully examine idle wells that have not been properly P&A'd and that are in close proximity to drinking water sources and in areas under consideration for new HVHF treatments, and require those wells to be P&A'd as a high priority and before shale gas drilling operations commence in those areas.

[79] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 35-36.

A report documenting specific cases of well pollution caused by NYS' improperly abandoned wells or orphaned wells could not be located; however, neighboring Pennsylvania has completed an analysis of this problem, and it sheds light on the problems NYS may encounter.

Pollution caused by improperly abandoned wells in Pennsylvania is documented in a 2009 report prepared by Pennsylvania Department of Environmental Protection (PADEP). The PADEP report lists 27 cases where improperly abandoned wells have been the source of groundwater contamination.[80] In some of the 27 cases the wells were abandoned according to the standard practices of the time, but now leak and need to be re-abandoned using improved materials and techniques. Some of the cases cited by PADEP include very old well construction techniques, for example, surface casing made out of wood that has rotted away, and wells with no surface casing or cement installed at all. These wells have provided a conduit for gas and other pollutants to reach groundwater through damaged or worn casing, poorly installed cement, or more directly where casing or cement was not initially installed.

PADEP also identified wells that need to be P&A'd, but have not yet been addressed due to the lack of a responsible party and/or on account of PADEP resource limitations.[81]

There were three cases cited by PADEP where fracture stimulations in an operating well communicated with a nearby abandoned well, causing a gas leak in the abandoned well.[82] PADEP's study highlighted the importance of locating orphaned and improperly abandoned wells near new oil and gas developments, and study shows the importance of properly abandoning wells before new development proceeds.

A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. The study found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[83] Clearly, the higher incidence rate of methane contamination in drinking water wells in shale gas extraction areas is not a coincidence, but is an indicator of shale gas drilling and completion operations mobilizing gas from the shale gas reservoir into protected aquifers. One of the most likely pathways for leaking of gas mobilized by HVHF is a nearby existing well that either was improperly constructed or improperly plugged. Given their failed cement, corroded casing, or lack of casing or cement, such improperly abandoned wells present vertical pathways to aquifers and drinking water resources.

Mechanical failure, human error, and engineering design flaws do occur in the construction and operation of wells. Indeed, groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

[80] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[81] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009. Cases include: Independent Valley News Migration, Allegheny County – SWRO – March 2009; Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008; Childers Migration, Washington County – SWRO – June 2005; Groshek Migration, Keating Twp., McKean County – NWRO – 2008; and Skinner Migration, Columbus Twp., Warren County – NWRO.

[82] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[83] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane Contamination of Drinking Water Accompanying Gas Well Drilling and Hydraulic Fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, p.2.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[84] PADEP inspectors "…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County."[85] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[86]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[87]

In May 2011, PADEP determined that improper well casing and cementing in Chesapeake Energy Corporation's shallower wells allowed migration into groundwater and caused contaminated 16 families' drinking water supplies in Bradford County.[88]

Pennsylvania has found that significant planning and research is needed to identify orphaned and improperly abandoned wells before drilling nearby wells. At a 2009 Stray Gas Workshop in Pennsylvania, Garrett Velosi, from the National Energy Technology Laboratory, pointed out that one of the main problems with stray gas leaks from abandoned wells is verifying the location of improperly abandoned wells. Records on older wells are often limited or non-existent. Mr. Velosi presented methods for locating unmarked abandoned wells. They include the use of historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).[89]

In January 2011, NYS' consultant Alpha Geoscience agreed that timely well plugging and abandonment requirements are important; however, it recommended that establishing "a specific timeline for plugging and abandonment is neither practical nor necessary."[90] Alpha Geoscience did not examine the large backlog of improperly abandoned wells in NYS or the risk of groundwater contamination from improperly abandoned wells located within the radius of influence of new gas wells and HVHF operations. Alpha Geoscience did not recommend any improved P&A procedures, despite NYCRR's outdated requirements. 6 NYCRR § 555.5 requires only 15' cement plugs, as compared to Texas, Alaska, and Pennsylvania regulations that require a series of 50'-200' cement plugs at various locations within the wellbore.

[84] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[85] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[86] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[87] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

[88] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[89] Veloski, G., National Energy Technology Laboratory, Methods for Locating Wells in Urban Areas – A Summary of Case Studies, Pennsylvania Stray Gas Workshop, November 2009.

[90] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011

HCLLC disagrees with Alpha Geoscience's recommendation to NYSDEC. Alpha Geoscience's recommendation also conflicts with prior advice from ICF to NYSERDA. HCLLC finds that it is practical and necessary to properly abandon wells on a reasonable timeline, and recommends that NYCRR be improved to include best practices and techniques for permanent wellbore abandonment.

2011 RDSGEIS: The 2011 RDSGEIS document is inconsistent on its recommendations for P&A'ing wells. In Chapter 5, NYSDEC concludes that no improvements are needed in the NYCRR regulations, but proposes changes to improve the regulations at 6 NYCRR § 555.5. In Chapter 6, NYSDEC concludes that it is not possible for HVHF treatments to intersect improperly abandoned wells; yet, in Chapter 7 NYSDEC proposed mitigation to address this very risk. These inconsistencies are further explained below, with recommendations for resolving them.

Chapter 5 of the RDSGEIS concludes that well plugging procedures and requirements in the existing NYCRR (described in the 1992 GEIS) are sufficient to address the risk of improperly abandoned wells. The 2011 RDSGEIS states:

> *As described in the 1992 GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors.* ***Proper plugging is critical for the continue protection of groundwater, surface water bodies and soil.*** *Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well [emphasis added].*[91]
>
> *When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.*
>
> *Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site. Removal of all surface equipment and full site restoration are required after the well is plugged.*
>
> *The plugging requirements summarized above are described in detail in Chapter 11 of the 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action.* ***Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review*** *[emphasis added].*[92]

[91] 2011 NYSDEC, RDSGEIS, Page 5-143.

[92] 2011 NYSDEC, RDSGEIS, Page 5-144.

While NYSDEC agrees that proper well P&A is critical to the protection of groundwater, surface water, and soil, it concludes that horizontal drilling and HVHF shale gas wells do not require any new or different P&A methods. However, this conclusion is inconsistent with NYSDEC's proposed revisions to the P&A procedures at 6 NYCRR § 555.5, this proposal suggests that the existing regulations do not represent best practices.

Recommendation No. 22: The SGEIS should be revised to state that the existing P&A procedures at 6 NYCRR § 555.5 were determined to be outdated and not best practice and that NYSDEC has proposed revisions. The basis for NYSDEC's proposed revisions should be justified in the SGEIS, and include a review of other states' best practices for P&A.

Chapter 5 of the RDSGEIS does not address: (1) whether NYS has a backlog of wells requiring P&A in close proximity to drinking water sources; (2) whether NYS has a backlog of wells requiring P&A in close proximity to areas under consideration for HVHF treatments; (3) whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and (4) whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

Recommendation No. 23: The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

For example, maps showing the location and depth of NYS' temporarily abandoned, improperly abandoned, or orphaned wells could not be located; however, this data is needed to ensure safe development of shale gas resources. The RDSGEIS proposes that operators identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[93]; however, ICF's 2003 report to NYSERDA points out that there are a large number of old wells in NYS where location or well condition data is not available in NYSDEC's Oil & Gas database. If NYSDEC has improved the Oil & Gas database to accurately document all existing wells this information should be included in the SGEIS and maps of the wells should be made available.

Recommendation No. 24: The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

In Chapter 6 of the RDSGEIS, NYSDEC discounts the risks of new HVHF shale gas wells communicating with nearby abandoned wells. NYSDEC relies on its consultant's (ICF) analysis that concludes it is not possible for HVHF treatments to intersect with improperly abandoned wells.[94] Yet, in Chapter 7, NYSDEC recommends precautionary measures to be taken by operators to ensure that wells

[93] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[94] 2011 NYSDEC, RDSGEIS, Page 6-52.

near HVHF operations are properly P&A'd to prevent freshwater contamination. The RDSGEIS is internally inconsistent on this point and the two diametrically opposed conclusions need reconciliation.

Recommendation No. 25: Chapter 6 of the SGEIS should be revised to be consistent with and support the Chapter 7 recommendation for HVHF operators to ensure all nearby wells are properly P&A'd before HVHF operations are conducted to mitigate the risk of HVHF treatments intersecting improperly abandoned wells. This requirement should also be codified in NYCRR.

In 2009 HCLLC recommended that preventative measures be taken to identify and properly abandon existing wells before proceeding with nearby shale gas drilling and HVHF operations. NYSDEC responded favorably to this recommendation by proposing that the operator identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[95] and by proposing that any improperly abandoned wells be plugged within that one-mile radius.[96] While NYS' recommendation is a step in the right direction, additional analysis is needed to justify the one-mile radius selected.

The RDSGEIS does not provide data on the maximum horizontal fracture propagation length that could occur at NYS' proposed 2000' depth cut-off. The RDSGEIS assumes the maximum horizontal well length will be 4000'. However, as highlighted in other sections of this report, current horizontal drilling technology allows for wells to be drilled substantially longer than 4000'. Fractures induced along that horizontal wellbore section can propagate several thousand feet from the well, depending on fracture treatment design parameters. Therefore, the wellbore length and the maximum fracture length combined could result in a radius of influence of more than one mile (5,280').

Recommendation No. 26: The SGEIS should provide technical justification for selecting a one-mile wellbore intersection radius and should explain the maximum horizontal drilling length and horizontal fracture length that corresponds with the proposed one-mile radius. This will be especially important for shallower wells where fractures tend to propagate on a horizontal plane, and where there will be a large number of potential shallow well intersection possibilities.

The SGEIS should examine the potential for longer wellbores and large fracture influence zones to occur now or in the future, and a wellbore intersection radius that corresponds to the largest areas of influence that are reasonably foreseeable should be included in the SGEIS as a mitigation measure and be codified in the NYCRR. Alternatively, if NYSDEC selects a one mile radius, the SGEIS should limit drilling length and horizontal fracture length in the SGEIS as a mitigation measure and in the NYCRR to ensure that the radius of influence does not extend beyond the one-mile impact area proposed.

The RDSGEIS proposes, in Table 11.1, that operators identify and plug wells within a one-mile radius, but this requirement is not translated into a permit condition or codified in NYCRR. Table 11.1 proposes:

> *Operators must identify and characterize any existing wells within the spacing unit and within one mile of proposed well and* ***plug and abandon any well which is open to the target formation or is otherwise and immediate threat to the environment*** *[emphasis added].*[97]

[95] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[96] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

[97] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

Appendix 6, PROPOSED Environmental Assessment Form Addendum requires the operator to complete the one-mile radius of investigation, yet, there is no requirement in Appendix 10 or in the NYCRR requiring the offset wells to be plugged by the HVHF operator if needed.

In direct contrast to the conclusions reached in Chapter 6, Chapter 7 of the RDSGEIS acknowledges the potential risk of HVHF wells intersecting improperly abandoned wells and proposes a process to address these risks:

> ***To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the Department's Oil and Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on available records and history of drilling in the area that the well's total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment.*** *If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations [emphasis added].*[98]

While Chapter 7 correctly acknowledges the need for P&A procedure improvement and review of nearby abandoned wells before HVHF treatments, NYSDEC incongruously proposes to limit P&A due diligence to: 1) wells that are within the HVHF well operator's control and 2) wells that are "accessible." This approach discounts the risks posed by improperly abandoned wells that are owned by another operator, orphaned, or difficult to access.

The inconsistency in P&A improvement recommendations persists in the Appendix 10 HVHF Permit Conditions where the recommended improvements in Chapter 7 are not included. The Chapter 7 recommendations are not included in the revised NYCRR either.

[98] 2011 NYSDEC, RDSGEIS, Page 7-58.

Recommendation No. 27: If a well was not properly P&A'd to current standards, the operator should be required to work with the well owner or take the initiative itself to ensure the well is properly P&A'd before new drilling begins and before a nearby HVHF treatment occurs. Approval of a HVHF well application should be conditioned on verification that any necessary P&A work is complete. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC should consider requiring operators to use a variety of proven methods to locate unmarked, abandoned wells, including: historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).

The proposed mitigation measure, requiring improperly abandoned or orphaned wells to be plugged prior to a HVHF treatment, should be included in Appendix 10, of the SGEIS and codified in the NYCRR.

Additionally, NYSDEC should request ICF to further examine additional technical and scientific questions that were not addressed in its analysis.

Foremost, ICF's report does not indicate that ICF evaluated the difference in reservoir pressure near a new shale gas wellbore, drilled into an un-depleted higher pressure gas reservoir, as compared to the lower reservoir pressure in the drainage radius around a well that previously served or is currently serving as a production well. The reservoir pressure in the drainage radius around a production well will be substantially lower creating a pressure sink around that well. By the laws of physics, gas and fluid will flow from higher pressure regimes to lower pressure regimes. Therefore, if a HVHF treatment intersects the drainage radius around a nearby pressure-depleted reservoir connected to an improperly abandoned well, the HVHF fluid and associated mobilized gas will continue to move towards the improperly abandoned well, not back to the new shale gas well as ICF suggests.

As explained in Chapter 10 of this report, industry data shows that HVHF treatments are propagating well beyond the shale zone into formations located above and sometimes below the shale, meaning that the HVHF treatment can potentially intersect the depleted well drainage area of a well that has produced from a zone above or below the shale.

However, ICF concludes that, once the HVHF treatment pressure ceases, all HVHF fluid will return to the shale gas well, and there is no possibility that HVHF fluid or associated mobilized gas will travel up an improperly abandoned well conduit. This conclusion is based on the assumption that the lowest pressure pathway for HVHF fluids injected into the formation is back to the shale gas well, but such assumption does not account for the possibility that a lower pressure regime at an abandoned or active well site could influence the flow of HVHF fluids and newly mobilized gas. It also discounts the possibility that other lower pressure intervals could be located above or below the shale zone that would preferentially accept HVHF fluids and gas mobilized during the treatment.

In these cases, HVHF fluids and gas would continue towards the improperly abandoned well and up the well conduit until pressure equilibrium is reached or into adjacent lower pressured reservoirs. This could result in HVHF fluids and associated gas that is mobilized during the HVHF treatment contaminating groundwater if an exposure pathway exists in the improperly abandoned well or from an adjacent lower pressure reservoir to a shallower protected water zone.

While it is true that HVHF fluids will flow back to the new shale gas well if such well presents the lowest pressure regime for fluid to flow to, this will not always be the case, as evidenced by the fact that not all the HVHF fluid returns to the well. The RDSGEIS states that:

> *Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9.*[99]

Therefore, several million gallons of HVHF treatment fluid remain in the reservoir and will travel to the lowest pressure formation/regime present, including such lower pressure regimes present around nearby existing wells that have previously produced hydrocarbons. An out-of-zone HVHF, as described in Chapter 10 of this report could potentially connect with this lower pressure reservoir, if not properly designed and implemented.

Secondly, ICF's analysis did not examine the maximum horizontal distance a HVHF could travel, nor identify minimum safe separation distances between horizontal fractures and abandoned wells. Thus, ICF did not attempt, to compare the maximum HVHF length to the closest distance that an abandoned well may occur.

Instead, ICF's analysis assumes that the HVHF impact radius would always be less than the distance to a nearby well (which may not be true in all cases, and will depend on reservoir characteristics and job design). ICF concludes, without basis, that a fracture created by a HVHF would never intersect a nearby well, but does not establish the well spacing distance required for this to be true nor does it consider the fact that Marcellus Shale fractures (as shown in Chapter 10 of this report) do routinely propagate out of zone.

Additionally, the Chapter 6 conclusion that it is not possible for a HVHF treatment to intersect an improperly abandoned well is discordant with three cases cited in PADEP's 2009 Report that document situations in which fracture stimulations in operating wells communicated with nearby abandoned wells, causing gas leaks in the abandoned wells.[100] PADEP's cases confirm that fracture stimulations, if improperly designed and executed, can intersect improperly abandoned and orphaned wells.

Recommendation No. 28: The SGEIS and NYCRR should require HVHF well operators to identify previously drilled wells that may be located within the hydraulic radius of the new shale gas well that may be affected during a HVHF treatment. The operator should be required to estimate the maximum horizontal and vertical extent of the fracture length that will be propagated and ensure that there are no abandoned or improperly abandoned wells in that intersection radius. An additional safety factor should be applied in this analysis to account for uncertainty in fracture design and implementation, and the potential for the actual fracture length to be longer than estimated (e.g. a conservative analysis is needed).

The HVHF treatment size should be designed to ensure that it does not intersect with any abandoned or improperly abandoned wells, with an additional margin of safety.

[99] 2011 NYSDEC, RDSGEIS, Page 5-99.

[100] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

Any improperly abandoned wells nearby, and just outside, the intersection radius should be properly abandoned to current standards before new drilling begins and before the HVHF treatment occurs.

NYCRR Proposed Revisions: Despite the 2011 RDSGEIS conclusion that no new P&A requirements are needed, and NYSDEC's consultant's (Alpha Geoscience) recommendation that no improvements are necessary, NYSDEC proposed revisions to its existing well P&A requirements at 6 NYCRR § 555.5, Plugging Methods, Procedures and Reports:

(a) The plugging of a well shall be conducted in accordance with the following sequence of operations[:] ***. The Division at its discretion may require the tagging of all plugs and require casing and/or cement evaluation logs to be run to determine proper plugging procedures. The following are minimum requirements for plugging and the department may impose additional requirements****: [emphasis added]*

> *(1) The well bore, whether to remain cased or uncased, shall be filled with cement from total depth to at least [15] 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity. Alternatively, a bridge topped with at least [15] 50 feet of cement shall be placed immediately above each formation from which the production of oil or gas has ever been obtained in the vicinity.*
>
> *(2) [If] For any casing [is to be] left in the ground, a cement plug of at least [15] 100 feet in length shall be placed [at the bottom of such section of casing] 50 feet inside and 50 feet outside of the casing shoe . Uncemented casing must be pulled as deep as practical with a 50-foot plug placed in and above the stub of the casing. If the uncemented casing is unable to be pulled the casing must be ripped or perforated 50 feet below the shoe of the next outer casing and a 100-foot plug placed across that shoe. A [similar] 50 foot plug shall be placed at [the top of such section of casing unless it shall extend to]the surface. [In the latter event, the casing shall be capped in any such manner as will prevent the migration of fluids and not interfere with normal soil cultivation.]*
>
> *(3) If casing extending below the deepest potable fresh water level shall not remain in the ground, a cement plug of at least [15] 50 feet in length shall be placed in the open hole at a position approximately 50 feet below the deepest potable fresh water level.*
>
> *(4) If the conductor casing or surface casing is drawn, a cement plug of at least [15] 50 feet in length shall be placed immediately below the point where the lower end of the conductor or surface casing shall previously have rested. The hole thereabove shall be filled with cement, sand or rock sediment or other suitable material in such a manner as well prevent erosion of the well bore area and not interfere with normal soil cultivation.*
>
> *(5) The interval between all plugs mentioned in paragraphs (1) through (4) of this subdivision shall be filled with [a heavy mud-laden] gelled fluid with a minimum density equal to 8.65 pounds per gallon with a 10 minute gel-shear strength of 15.3 to 23.5 pounds per hundred square feet or other department approved fluid.*

NYSDEC's proposed revisions are a step in the right direction. Overall, NYSDEC proposes to require longer cement plugs, weighted mud, and some additional QA/QC procedures, including tagging the cement plugs and possibly running cement evaluation logs.

NYSDEC's existing P&A regulations require short cement plugs (15'), which are woefully inadequate, compared to current best practices of installing a series of 50'-200' cement plugs within a wellbore, and removing corroded casings to isolate water resources. Unfortunately, this means that most of NYS'

abandoned wells, if plugged to NYCRR's existing standards, are not likely to provide adequate groundwater protection. To address this problem, the P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards.

Recommendation No. 29: P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards and this requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC's proposed increase to 50' cement plug length is an improvement; however, best practices used in other states such as Texas, Alaska, and Pennsylvania require longer cement plugs. NYSDEC should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while NYSDEC has proposed to revise the NYCRR to require a 50' cement barrier, Alaska requires double that protection at 100'.[101] Pennsylvania recently upgraded its P&A requirements from its previous 50' standard to plugs of 50'-100'.[102] Texas requires cement plugs ranging from 50'-200' at numerous locations in the well, and requires cement QA/QC procedures.[103] For example, Texas requires each cement plug to be a minimum of 200' in length and extend at least 100' below and 100' above the top of each hydrocarbon stratum and the base of the deepest protected water stratum, which is a substantial difference from NYS' current requirement for 15' plugs.

Recommendation No. 30: The SGEIS mitigation measures and NYCRR should be revised to clearly specify that:

Plugging a wellbore should be performed in a manner that ensures all hydrocarbons and freshwater are confined to their respective indigenous strata, and prevented from migrating into other strata or to the surface.

All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to at least 100 feet above the top of all hydrocarbon-bearing strata (200' plug).

The plugging of a well should include effective segregation of uncased and cased portions of the wellbore to prevent the vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to at least 100 feet above the casing shoe (200' plug).

The operator should be required to submit records to NYSDEC to demonstrate that the well is P&A'd in compliance with regulations.

NYSDEC should consider specifying the grade of cement required to plug the well. It should also consider requiring the use of gas blocking agents.

[101] 20 AAC 25.

[102] PA Code, § 78.91.

[103] 16 TAC Part 1, § 3.14.

Revisions to the NYCRR include some improved QA/QC procedures, but these revisions are loosely written and do not specify when QA/QC procedures will be mandatory. For example, it is best practice to tag all cement plugs to verify placement depth; this should not be an optional, discretionary procedure. Also, NYSDEC should specify under what circumstances a cement evaluation tool will be required.

Recommendation No. 31: The SGEIS mitigation measures and NYCRR should be revised to require cement quality standards, including the use of gas blocking cement. The SGEIS and NYCRR should require tagging of all cement plugs and provide instructions on when additional cement evaluation tools must be run.

10. HVHF Design and Monitoring

Background: In 2009, HCLLC recommended that NYSDEC revise its regulations to specify and require best technology and best practices for collecting data, and modeling, designing, implementing, and monitoring a fracture treatment, including:

(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 HVHF treatments;

(c) HVHF 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) Starting with smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. 4,000' deep and 150' thick);[104]

(f) Using the experience gained with fracture testing on deeper sections of the Marcellus 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); and

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

In 2009, HCLLC recommended that fracture treatments be carefully monitored and shut down if pressure data indicates casing leaks. HCLLC noted the American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, [105] and that fracture treatments should be immediately shutdown if abnormal pressures indicate a casing leak. The 2011 RDSGEIS now requires the operator to carefully monitor fracture treatments and shut down the treatment if data indicates casing leaks or out-of-zone fractures. This is an important improvement to the SGEIS.

Experts agree that Marcellus Shale gas production can be maximized by: 1) drilling long horizontal wells to increase the drainage area and 2) conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments be properly designed and sized to remain <u>within</u> the shale zone. Fracture treatments that propagate <u>outside</u> the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport. There is extensive industry literature on the importance of hydraulic fracture design, modeling, and field verification to optimize fracture stimulation. Therefore, in 2009 HCLLC recommended that the DSGEIS be improved to provide additional technical and scientific data and require specific mitigation, ensuring that operators are designing jobs that will not fracture out-of-zone.

[104] Smaller, deeper fracture treatments could be used initially in NYS, the performance examined, the predictive model improved based on that data, and then fracture treatment size and proximity to protected waters and other wellbores could be modified, as confidence increases in the predictive ability of the model to ensure a safe and favorable result.

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

Pollutant transport and pollutant toxicity issues are addressed in Dr. Tom Myers' and Dr. Glenn Miller's reports to NRDC on the 2009 DSGEIS and the 2011 RDSGEIS. HCLLC's recommendations center on what type of data, analysis, tools, and methods an engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

In 2009, HCLLC observed that NYSDEC and/or operators had not provided sufficient data to demonstrate that a HVHF treatment can be contained to the Marcellus Shale. HCLLC pointed out that the 2009 DSGEIS did not require the operator to demonstrate that it is equipped with sufficient expertise, training, qualifications, and engineering tools to safely design, implement, and assess the performance of HVHF treatments. HCLLC recommended that NYSDEC consider operator qualifications.

HCLLC's recommendations on the 2009 DSGEIS explained that it is best practice in newly developed formations, such as the NYS Marcellus Shale, to build hydraulic fracture models. Fracture models are used by engineers to safely design fracture treatments. During actual fracture stimulation treatments, data are collected to verify model accuracy, and the model is continually refined to improve its predictive capability.

Because fracture treatments may be executed several thousand feet below the surface of the earth, and can only be indirectly observed, it is important for engineers to have a 3D model to guide design. While 3D modeling is not an exact science, the model provides an engineer with an estimating method for predicting both horizontal and vertical fracture length.

As further explained below, data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability.

In newly developed areas it is important to conduct initial HVHF treatments in the lowest risk zones, far below protected aquifers and with large horizontal offsets from existing wells. Until the predictive capability of site-specific models improves from the input of actual field data, larger buffer zones should be used. Absent hydraulic fracture modeling in newly developed areas such the NYS Marcellus Shale, engineers would blindly be making decisions on the size, type, and execution of HVHF treatments.

NYS' consultant, Alpha Geoscience, agreed with HCLLC's 2009 recommendations and in January 2011 reported to NYSDEC that:

> *Harvey Consulting's [HCLLC] assessment of the dSGEIS' discussion of hydraulic fracture design and monitoring is thorough…*
>
> *Harvey Consulting has thoroughly documented its discussion of hydraulic fracture design and monitoring, citing professional journal articles, professional conference papers, technical guidance documents, and consultant reports.*[106]

Alpha Geoscience recommended to NYSDEC that HCLLC's 2009 recommendations be included in the SGEIS:

> *Harvey Consulting's ideas should be considered for inclusion in the dSGEIS as possible permit conditions, especially for the first wells drilled in an area.*[107]

[106] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 26-27.

[107] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 28.

While Alpha Geoscience's report acknowledges the importance of proper HVHF design and monitoring, it includes several misrepresentations about HCLLC's 2009 comments that require correction.

First, Alpha Geoscience incorrectly contends that HCLLC recommended industry and NYS develop separate hydraulic fracture models; this is not correct. HCLLC recommended that industry develop models, **or** that joint model funding be implemented as a more cost-effective approach. Typically, companies build their own proprietary models to seek competitive advantage, especially in newly developed areas where the models are used as part of the competitive bidding process. However, it is possible for one or more companies to pool resources to develop a joint model as a cost savings.

Second, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform fracture modeling at every location, **including locations that have been thoroughly modeled and assessed.** Alpha Geoscience concluded that this would be extremely costly compared to the technical value. HCLLC did not recommend HVHF modeling be conducted at locations that have been "thoroughly modeled and assessed." Logically, if this work has already been completed, there is no reason to repeat it.

HCLLC did recommend that NYSDEC require operators to complete modeling prior to each fracture treatment to ensure that the fracture is properly designed and planned to be contained to the Marcellus Shale zone. This is not a significant amount of work per well for experienced operators, with working models. HCLLC also recommended that operators collect data during fracture treatments to further refine hydraulic fracture models. HCLLC pointed out that as NYS shale development is in its infancy, hydraulic fracture model work has not yet been completed, and therefore is needed.

Once a hydraulic fracture model is built and populated with data specific to the NYS Marcellus Shale, running a well-specific HVHF treatment scenario is an efficient process, and an important quality control and quality assurance measure. It does not appear that Alpha Geoscience is familiar with the reservoir simulators used for oil and gas work, because their recommendation to construct a hydraulic fracture model for the Marcellus Shale, and then use it only on the initial wells constructed, is inconsistent with industry practice. Model quality improves over time. As additional data is collected and the model is refined, it becomes an increasingly valuable tool to the operator. High-quality models are an essential tool for designing fracture treatments in challenging circumstances and locations.

In 2009, HCLLC explained that industry agrees there is a high level of uncertainty in NYS Marcellus Shale development; industry recommends engineering and geophysical data work to reduce that uncertainty. HCLLC's recommendations in 2009 stated:

> ***Marcellus Experience Very Limited:*** *Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.*[108] *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.*[109] *Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the dSGEIS.*

[108] 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.

[109] 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.

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].*[110]

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.[111]

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*

[110] 2009 NYSDEC, DSGEIS, ICF Task 2 Report, Page 1.

[111] 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.

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.

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.

Third, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform a minifracture treatment at every location, including locations that have been thoroughly modeled and assessed. HCLLC did not recommend that a minifracture be conducted at every well. Instead, HCLLC recommended that minifractures be conducted in a few different areas of NYS to further refine hydraulic fracture models. HCLLC's 2009 recommendations stated:

Technology is available to assess actual fracture growth including: minifracs,[112] microseismic fracture mapping,[113] tilt surveys, well logging (e.g., tracer and temperature surveys[114]), etc.[115] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[116] ***This data***

[112] 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.

[113] 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.

[114] 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.

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

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

> ***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 [emphasis added].*

HCLLC's 2009 recommendations also noted that:

> ***While NYSDEC's consultant, ICF[117], 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*** *[emphasis added]*.
>
> *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.[118]*
>
> *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.*
>
> *A literature review was completed by the author [HCLLC] 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' 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.*

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

[118] 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.

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' 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"* [119] *[emphasis added].*

Marcellus Shale thickness lessens substantially in western NYS to less than 75' for roughly one-third of the total anticipated development area.[120] HVHF treatments in thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken by tailoring the design to the geophysical properties of the shale, 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 an increase in produced water volumes. Yet, NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it is possible to inadvertently fracture out-of-zone. ICF examined the potential for fracture fluids to propagate vertically and contaminate overlying drinking water aquifers. ICF recommended a 1,000' vertical offset be used.

HCLLC agrees that the use of vertical and horizontal offsets (buffer zones) is a prudent approach. The next step is to determine the size of the offsets. Initially, in new areas, offsets should be large, and then may decrease over time, as field data is obtained and predictive capability is refined.

[119] 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.

[120] 2009 NYSDEC, DSGEIS, Figure 4.9.

In 2009, HCLLC pointed out that the 1,000' vertical offset proposed by ICF is not technically supported, and a horizontal buffer zone is also needed. HCLLC recommended that vertical and horizontal offsets be based on actual field data, 3D reservoir simulation modeling, and a peer-reviewed hydrological assessment. HCLLC recommended these steps be taken to ensure aquifers are protected and nearby wellbore intersections are avoided.

The 2011 RDSGEIS still does not provide technical justification for the proposed minimum 1,000' vertical offset, nor does it make a recommendation for a horizontal offset from existing wells.

Instead, the 2011 RDSGEIS provides data that shows HVHF treatments in the Marcellus Shale have propagated vertical fractures up to 1500' in length, and horizontal fractures can extend hundreds to thousands of feet, as further explained below. These data do not support the proposed buffers.

The 2011 RDSGEIS: The 2011 RDSGEIS agrees that in new areas hydraulic fracture model development and design is important, citing recommendations from the Ground Water Protection Council and its consultant ICF; yet, incongruously the RDSGEIS concludes it is unnecessary for operators to be required do this work in NYS (as a SGEIS mitigation measure or a NYCRR requirement).

> *Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected.* ***In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures. After the procedure is actually performed, the data gathered can be used to optimize future treatments. Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. ICF International, under contract to NYSERDA*** *to provide research assistance for this document,* ***observed that fracture monitoring by these methods*** *is not regularly used because of cost, but* ***is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models*** *[emphasis added].*[121]

NYSDEC's consultants (Alpha Geoscience and ICF), the Ground Water Protection Council, HCLLC, and industry all agree:

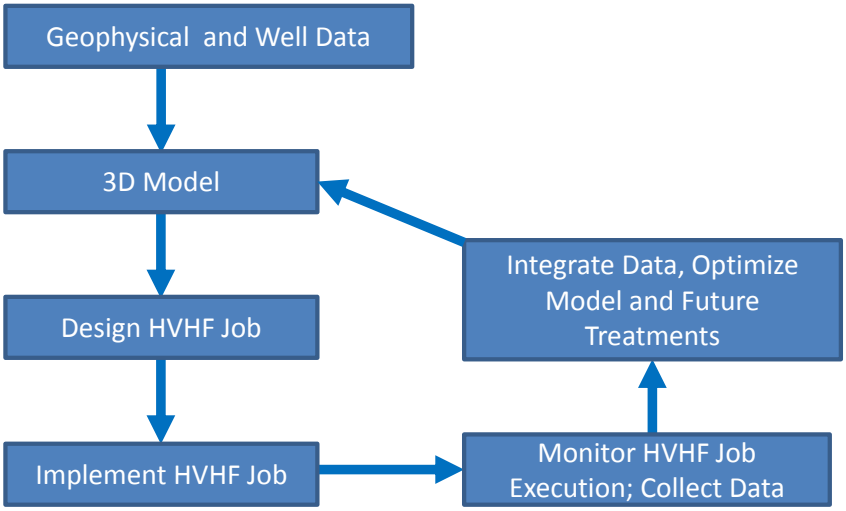
- There is a need for computer modeling on new gas shale play areas to simulate various fracturing designs and their effects on the height, length, and orientation of the induced fractures;
- After the HVHF treatment is actually performed, gathered data should be used to optimize future treatments; and
- There is technology available to further refine treatment design, including microseismic fracture mapping, tilt measurements, tracers, and proppant tagging.

However, these points of agreement are not reflected in the RDSGEIS, permit conditions, or NYCRR revisions. Remarkably, the 2011 RDSGEIS only has a few paragraphs in the entire 1,537 page document that discuss the importance of HVHF modeling and post-fracture assessment work (Chapter 5.8), and these recommendations are later disregarded in Chapter 7 proposed mitigation.

[121] 2011 NYSDEC, RDSGEIS, Page 5-88.

The use of 3D reservoir simulation to more accurately predict vertical and horizontal fracture growth is not new; reservoir simulation models have been used by petroleum engineers for decades. However, computational efficiency and model design have improved considerably, and more sophisticated simulation techniques are now available for shale gas reservoirs.

The basic engineering approach for populating a 3D reservoir simulation model is shown in the simplified flow diagram below, with geophysical data (seismic, well logs, core, samples, etc.) and existing nearby well data serving as the starting point. Once a model is built, it is used to design and optimize a safe and effective HVHF job. Data are gathered while the job is implemented, and those data are used to refine the model and improve future HVHF treatments.



There is abundant industry literature explaining the need for hydraulic fracture modeling and microseismic mapping, especially for new shale play developments, such as in NYS.

NYSDEC should recognize that the use of refined, site-specific models to optimize HVHF jobs is industry best practice. Quality operators with high standards routinely do this work. It should not be considered a burdensome practice, but rather a necessary requirement to protect groundwater and the environment.

Furthermore, it is economically attractive for an operator to use HVHF modeling. Models aid industry in making informed decisions, and prevents fracturing out-of-zone, which maximizes gas recovery rates.

Microseismic mapping has become a key tool for better understanding shale gas heterogeneities, identifying reservoir faults, and measuring actual fracture propagation orientation and length.

A 2010 industry paper[122] written by Rex Energy Corporation and MicroSeismic Inc. explains the importance of microseismic mapping for shale gas engineering:

> *By using microseismic source locations and mechanisms in conjunction with other geological and geophysical knowledge of an area, engineering and completion methods can be quickly corrected and enhanced. Induced fracture height, length, and placement influence the location, orientation and spacing of subsequent wells.* ***Microseismic monitoring allows for identification and characterization of unknown faults which intersect the wellbore and may significantly affect reservoir production and stimulations****. Formations with limited exploration with limited exploration data, such as the Marcellus shale, are ideal candidates for microseismic monitoring [emphasis added].*
>
> *In this case study, we will show how the* ***microseismic monitoring of a hydraulic fracture treatment in the Marcellus Shale identified a pre-existing natural fault which intersected the wellbore*** *[emphasis added].*

A 2011 industry paper[123] written by Marquette Exploration (a Marcellus Shale operator) and Schlumberger (an industry contractor), titled "Integrating All Available Data to Improve Production in the Marcellus Shale," emphasizes the importance of HVHF design and monitoring:

> *The operator featured in this paper is a small independent with Marcellus Shale areas of operation spanning across Belmont and Jefferson counties, eastern Ohio (Fig.2). This paper describes the methodology used by the operator to systematically gather the critical data during a pilot program to enhance the knowledge of their reservoir and develop optimized completion strategies and stimulation designs, thereby maximizing the true economic value of their asset.*
>
> *To build realistic property models, input from team members from different disciplines is required; in this study, team members included a geophysicist, geologist, petrophysicist, and reservoir engineer. Once the 3D structural model was completed, individual log measurements and interpreted properties from petrophysical, geomechanical, and image logs were incorporated in the model.*

Marquette Exploration's paper concludes:

- *Delineating a reservoir early on in the play and gathering as much data as possible can improve the drilling and completion design of the initial horizontal wells in the field to reduce the time and cost for an operator to get up the learning curve.*
- *Using all available data can greatly enhance the understanding in a field which, in turn, can improve the lateral design. Core data are imperative to calibrate petrophysical and geomechanical logs to further refine log models in other wells in an area.*
- *Seismic data in conjunction with strategically placed vertical logs can be used to construct a detailed static 3D geological model.*

[122] Hulsey, B.J., and Cornette, B. (MicroSeismic Inc.), and Pratt, D. (Rex Energy Corporation), Surface Microseismic Mapping Reveals Details of the Marcellus Shale, Society of Petroleum Engineers, SPE Paper 138806, 2010, Page 1.

[123] Ejofodomi, E., Baihly, J., Malpani, R., Altman, R, (Schlumberger), and Huchton, T., Welch, D., and Zieche, J., (Marquette Exploration), Integrating All Available Data to Improve Production in the Marcellus Shale, Society of Petroleum Engineers Paper, SPE 144321, 2011.

- *The thickness, depth, and continuity for shale sub-layers can vary greatly over a small area, so a pilot hole can be imperative to calibrate the geologic model for lateral landing point determination.*
- *The geologic model showed that the reservoir properties varied across the area of interest.*
- *Stochastic modeling can be used to successfully propagate interpreted log properties from a few wells across a large acreage.*
- *A novel reservoir modeling technique, Microseismic Fracture Network (MFN), was developed using microseismic data to properly describe the created complex fracture network.*

A 2010 industry paper[124] written by El Paso Exploration and Production and StrataGen Engineering stresses the importance of HVHF design:

> *…a primary conclusion is that as reservoir permeability decreases, proper well type selection and* ***effective hydraulic fracture stimulation design become much more crucial*** *[emphasis added].*
>
> ***Additional modeling with specifics must be performed to evaluate well type, fracture design, and spacing requirement for a specific well or formation*** *[emphasis added].*

A 2011 industry paper[125] written by Schlumberger also stresses the importance of HVHF design and monitoring:

> *The completion strategy and hydraulic fracture stimulation are the keys to economic success in unconventional reservoirs.* ***Therefore, reservoir engineering workflows in unconventional reservoirs need to focus on completion and stimulation optimization*** *as much as they do well placement and spacing.* ***This well-level focus requires the integration of hydraulic fracture modeling software and the ability to utilize measurements specific to unconventional reservoirs*** *[emphasis added].*
>
> ***It is very important to properly model hydraulic fracture propagation and hydrocarbon production mechanisms in unconventional reservoirs****, a significant departure from conventional reservoir simulation workflows.* ***Seismic-to-simulation workflows in unconventional reservoirs require hydraulic fracture models that properly simulate complex fracture propagation*** *which is common in many unconventional reservoirs, algorithms to automatically develop discrete reservoir simulation grids to rigorously model the hydrocarbon production from complex hydraulic fractures, and the ability to efficiently integrate microseismic measurements with geological and geophysical data.* ***The introduction of complex hydraulic fracture propagation models now allows these workflows to be implemented*** *[emphasis added].*

A 2010 industry paper[126] written by StrataGen Engineering and CMG (industry consultants) again highlights the importance of HVHF design and monitoring:

[124] Shelley, R.F., Lolon, E., and Dzubin, B. (StrataGen Engineering), and Vennes, M. (El Paso Exploration and Production), Quantifying the Effects of Well Type and Hydraulic Fracture Selection on Recovery for Various Reservoir Permeability Using a Numerical Reservoir Simulator, Society of Petroleum Engineers Paper, SPE 133985, 2010, Pages 1 and 12.

[125] Cipolla, C.L., Fitzpatrick, T., Williams, M.J., and Ganguly, U.K., (Schlumberger), Seismic-to-Simulation for Unconventional Reservoir Development, Society of Petroleum Engineers Paper, SPE 146876, 2011, Page 1.

> *The widespread application of microseismic mapping has significantly improved our understanding of hydraulic fracture growth in unconventional gas reservoirs (primarily shale) and led to better stimulation designs. However, the overall effectiveness of stimulation treatments is difficult to determine from microseismic mapping, as the location of proppant and distribution of conductivity in the fracture network cannot be measured (and are critical parameters that control well performance). Therefore* ***it is important to develop reservoir modeling approaches that properly characterize fluid flow in and the properties of a complex fracture network, tight matrix, and primary hydraulic fracture (if present) to evaluate well performance and understand critical parameters that affect gas recovery*** *[emphasis added].*
>
> *Given the complex nature of hydraulic fracture growth and the very low permeability of the matrix rock in many shale-gas reservoirs combined with the predominance of horizontal completions,* ***reservoir simulation is commonly the preferred method to predict and evaluate well performance*** *[emphasis added].*
>
> *The most rigorous method to model shale-gas reservoirs is to discretely grid the entire reservoir, including the network fractures, hydraulic fracture, matrix blocks, and un-stimulated areas – but this increases computational time. However, with the continual advances in computing power, much more complex numerical models can be efficiently utilized.*

In 2010, Atlas Energy Resources published a Society of Petroleum Engineering Paper that explained the importance of reservoir characterization, modeling, the use of minifracs, and the use of microseismic data. Atlas Energy Resources explained that the use of advanced technology is good business:

> *This paper describes a procedure to enhance production in the Marcellus shale while optimizing economics through integration of minifrac, fracture treatment, microseismic, and production data technologies.*
>
> *Application of this integrated technology approach will help prodvide the operator with a systematic approach for designing, analyzing, and optimizing multi-stage/multi-cluster transverse hydraulic fractures in horizontal wellbores.*[127]

An engineering analysis and modeling prior to a HVHF treatment provides industry, regulators, and the public with confidence that the treatment has been thoroughly evaluated and designed to protect the environment. It is not sufficient for industry and NYSDEC to say this work is being done, while being unwilling to require it. If this work is being done, then creating a formal requirement in the SGEIS and NYCRR does not impose an incremental burden on the operator. Resistance to a formal requirement should signal to NYSDEC that industry best practice is not always followed.

While industry literature explains the need for hydraulic fracture modeling, this does not guarantee it will actually be implemented by all shale gas operators in NYS. Shale gas drilling has attracted numerous small, less experienced operators. Computational modeling requires personnel with expertise in building models, running them, and refining datasets. If the operator does not have sufficient in-house engineering and geophysical expertise, it should be required to hire experts to provide the necessary expertise.

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[126] Cipolla, C.L., Lolon, E.P. (StrataGen Engineering), Erdle, J.C., and Rubin, B. (CMG), Reservoir Modeling in Shale-Gas Reservoirs, Society of Petroleum Engineers Paper, SPE 125530, 2009, Pages 1,3, and 4.

[127] Henry Jacot, R. (Atlas Energy Resources), Bazan, L.W. (Bazan Consulting, Inc.), Meyer, B.R. (Meyer & Associates Inc.), Technology Integration – A Methodology to Enhance Production and Maximize Economics in Horizontal Marcellus Shale Wells, Society of Petroleum Engineers Paper, SPE 135262, 2010, Page 1.

Recommendation No. 32: Best practices for HVHF design and monitoring should be included in the SGEIS as a mitigation measure, and codified in NYCRR as a minimum standard.

Additionally, Alpha Geoscience, ICF, Ground Water Protection Council, HCLLC, and industry all agree that additional technical work is needed to develop new shale gas play areas; yet the 2011 RDSGEIS does not require the operator to develop or maintain a hydraulic fracture model. Instead, the 2011 RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned.[128]

Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. This approach would not be in NYS' best interest.

Instead, NYS needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment costs.

The 2011 RDSGEIS does not require a HVHF design plan.[129] The RDSGEIS does not require the operator to:

(a) Estimate the vertical and horizontal fracture length;

(b) Verify that the proposed HVHF design will not intersect protected groundwater or nearby wells;

(c) Use a site-specific hydraulic fracture model, based on NYS specific shale characteristics and the operational design parameters of the planned HVHF job (volume, pressure, rate, etc.).

Recommendation No. 33: The SGEIS and NYCRR should require the operator to:

(a) Estimate the maximum vertical and horizontal fracture propagation length for each well, and submit technical information (e.g. model output) with its application to support its computations.

(b) Describe in its post-well completion report whether the predicted vertical and horizontal fracture propagation lengths were accurate, or note discrepancies.

(c) Certify that the actual HVHF job was implemented safely, and fracture propagations did not intersect protected aquifers or nearby wells.

Additionally, NYS should reserve the right, and provide funding, to periodically review industry's models and computations to assess quality and verify this work is being completed.

[128] 2011 NYSDEC, RDSGEIS, Page 5-88.

[129] The operator is only required to verify that the vertical offset of 1000' is achieved and the shale is at least 2000' deep.

The 2011 RDSGEIS assumes that any HVHF job, no matter the volume, no matter the pressure, and no matter the shale thickness, will be safe, as long as it is conducted at a depth below 2,000'. The 2011 RDSGEIS recommends that site-specific SEQRA reviews be limited to wells shallower than 2000' and within 1000' of a protected aquifer.[130] The RDSGEIS lacks technical and scientific data to support the hypothesis that all HVHF treatments, regardless of design, at 2000' or deeper will be safe. Additionally, the RDSGEIS does not address safe horizontal fracture length.

NYSDEC does not provide data on HVHF treatments conducted between 2000' and 5000' deep; yet, NYS proposed to allow shale gas drilling at these depths. Instead, the RDSGEIS relies on limited data collected from Marcellus Shale fractures conducted in other states at depths below 5000'. However, even industry points out that data collected in one part of the Marcellus Shale cannot be applied to the entire shale.

For example, Guardian Exploration and Universal Well Services reports that optimal Marcellus Shale HVHF treatments are still being developed, and that a "one-size-fits-all approach should not be expected. They anticipate that industry will examine the use of higher rates and increased fluid volume and proppant mass in the future resulting in varied fracture lengths from current HVHF jobs:

> ***Much work remains to be done in determining the optimal stimulation treatment for the Marcellus shale***. ***Certainly given the extremely large geographic area encompassed by the Marcellus play, it should not be expected that one size will fit all.*** *While the treatment discussed here has been considered successful,* ***future projects will examine the effects of increased rate, increased volumes in terms of both overall fluid volume and proppant mass, the effects of varying the proppant mesh ratios and concentrations, and optimization of flowback/cleanup rates***. *The utilization of evaluation tools such as microseismic monitoring of fracture growth and horizontal drilling and completions to enhance reservoir development should also prove to be beneficial [emphasis added].*[131]

As HVHF treatment methods continue to evolve, NYSDEC must either set a limit in the SGEIS and NYCRR for the upper bounds of a safe HVHF job, or it must have a process in place for industry to provide site-specific engineering to support each well application to ensure that new HVHF designs are safe.

NYSDEC assumes that 1000' vertical separation between the bottom of the protected groundwater zone and the top of the shale zone where HVHF will occur is sufficiently protective, regardless of shale thickness, HVHF job size, and other subsurface characteristics. However, this approach is not technically supported. The 2011 RDSGEIS concludes:

> *As explained in Section 6.1.5.2, the conclusion that* ***harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone.*** *The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing [emphasis added].*[132]

[130] 2011 NYSDEC, RDSGEIS, Page 7-59.

[131] Fontaine, J., and Johnson, N. (Universal Well Services), and Schoen, D. (Guardian Exploration), Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper, SPE 117772, 2008, Page 11.

[132] 2011 NYSDEC, RDSGEIS, Page 7-59.

Neither the 2009 DSGEIS nor the 2011 RDSGEIS contain site-specific NYS Marcellus Shale hydraulic fracture model data to support NYSDEC's conclusion that a 1,000' vertical separation will be protective in all cases in NYS, especially where thinner, shallower shales are present. Furthermore, the 2011 RDSGEIS lacks data on vertical and horizontal fracture propagation in the Marcellus Shale at depths between 2000' and 5000' (depths that NYS proposes to permit).

The behavior of HVHF propagation in NYS is not currently well understood. HCLLC was unable to locate any NYS site-specific hydraulic fracture models for the Marcellus, Utica, or other low-permeability reservoirs. If these models exist, they should be described in the SGEIS, and NYSDEC should explain how it used the data from these models to inform its SGEIS.

Instead, the RDSGEIS currently relies on Marcellus Shale HVHF data from other states that may not be applicable to NYS. For example, NYSDEC points to data collected on 400 Marcellus hydraulic fractures conducted in Pennsylvania, West Virginia, and Ohio. This data was summarized in a three page article in the American Oil & Gas Reporter in July 2010:

> *Four hundred Marcellus hydraulic fracturing stages in Pennsylvania, West Virginia and Ohio have been mapped with respect to vertical growth and distance to the deepest water wells in the corresponding areas. Although many of the hydraulic fracturing stages occurred at depths greater than the depths at which the Marcellus occurs in New York, the results across all depth ranges showed that induced fractures did not approach the depth of drinking water aquifers. In addition, as previously discussed, at the shallow end of the target depth range in New York, fracture growth orientation would change from vertical to horizontal.*[133]

NYSDEC's conclusions rely heavily on the American Oil & Gas Reporter three-page article (Fisher, 2010); yet NYSDEC does not further investigate the origin of the data contained in this article or its implications for shale development in NYS. Fracture growth is a function of type of formations located above and below the Marcellus Shale. Subsurface geology will vary across states and the RDSGEIS does not explain how this data is applicable to NYS. For example, this article:

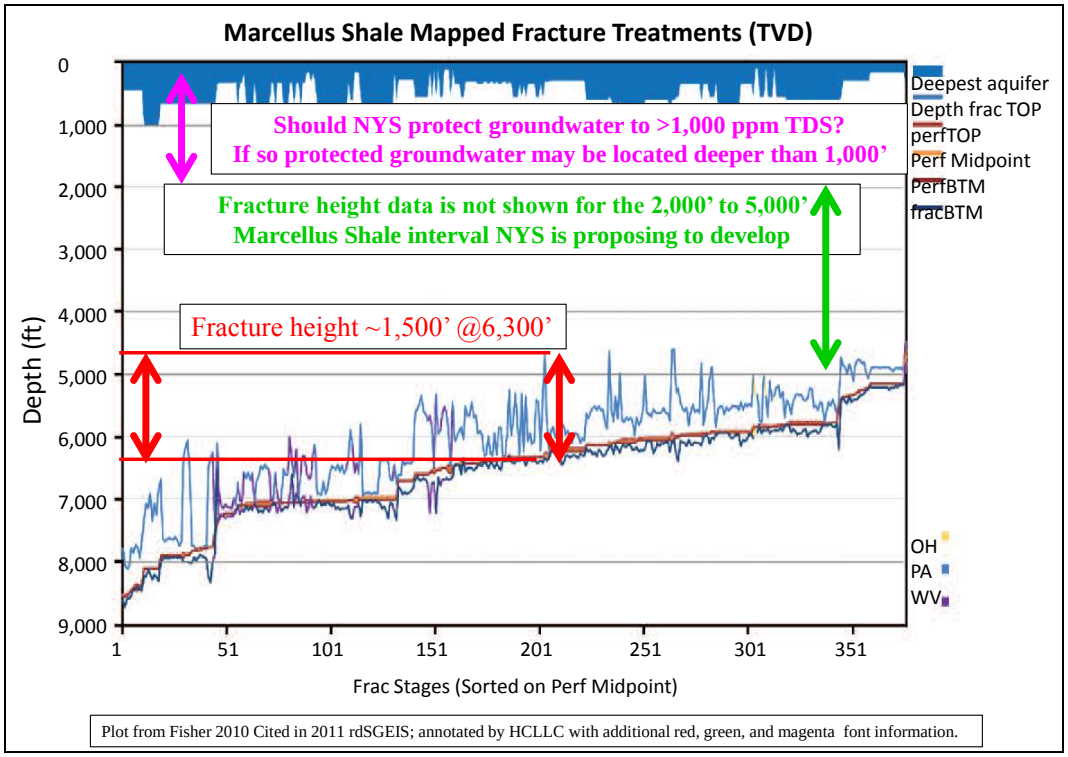
- Does not provide any information on the maximum HVHF job size (volumes, pressures, rates, etc.) to verify whether the fracture treatments conducted and analyzed are equivalent to the maximum HVHF job size anticipated in NYS;
- Does not provide any information on the Marcellus Shale thickness or geophysical properties present during the HVHF treatments;
- Shows that vertical fractures in excess of 1000' were observed (the plot, which is copied from the Fisher 2010 report and provided below, shows a 1500' vertical fracture propagated at 6300');
- Does not show what the vertical fracture growth height would be in the 2000-5000' Marcellus Shale depth interval that NYS proposes to develop; and,
- Does not show the horizontal distance that a fracture will propagate at the shallower shale depths NYS plans to develop.

[133] 2011 NYSDEC, RDSGEIS, Page 6-56.

A more in-depth technical paper written by Kevin Fisher (Halliburton) in 2011 appears to be the origin of the data cited in the American Oil & Gas Reporter article. Fisher's 2011 paper[134] concludes that:

> ***Fracture lengths can sometimes exceed a thousand feet*** *when contained with a relatively homogeneous layer [emphasis added].*
>
> ***At depths deeper than about 2,000 ft****, the vertical stress or overburden is generally the largest single stress so* ***the principal fracture orientation is expected to be vertical*** *on deeper wells [emphasis added].*
>
> ***At some point on shallow wells, the overburden stress will decrease to a point where it is less than the maximum horizontal stress and, at this point, one would expect the fracture growth to be horizontal and not vertical.*** *As wells get shallower, and the overburden stress lessens, mapped fractures are typically observed exhibiting increasingly larger horizontal components.* ***All of the fractures do not necessarily turn horizontal; they might have significant vertical and horizontal components with more of a T-shaped geometry,*** *but the horizontal components can become significant and could thieve away enough fluid causing a blunting effect, limiting upward fracture-height growth [emphasis added].*

The Marcellus fracture height figure shown in the American Oil & Gas Reporter is provided below; HCLLC annotated it to identify additional evaluation that is needed for NYS.



Plot from Fisher 2010 Cited in 2011 rdSGEIS; annotated by HCLLC with additional red, green, and magenta font information.

The use of vertical offset limits to separate hydrocarbon recovery operations from protected aquifers is a reasonable approach, but it must be scientifically and technical supported. While it is possible that a 1,000' vertical offset may potentially be sufficiently protective; the 2011 RDSGEIS does not provide sufficient scientific data or technical examination to support this recommended threshold.

[134] Fisher, K. and Warpinski, N., Pinnacle- A Halliburton Service, Hydraulic Fracture-Height Growth: Real Data, Society of Petroleum Engineers Paper, SPE 145949, 2011, Pages 1-2 and 5.

In addition to understanding the maximum vertical fracture propagation height, horizontal fracture propagation distance is an important consideration, especially when developing shallower shale zones. Fractures in shallower formations will tend to propagate on the horizontal plane. HVHF treatments should be designed to prevent fractures from intersecting with existing improperly constructed and improperly abandoned wells, and transmissive faults and fractures, which can provide pollutants a direct pathway to protected groundwater resources.

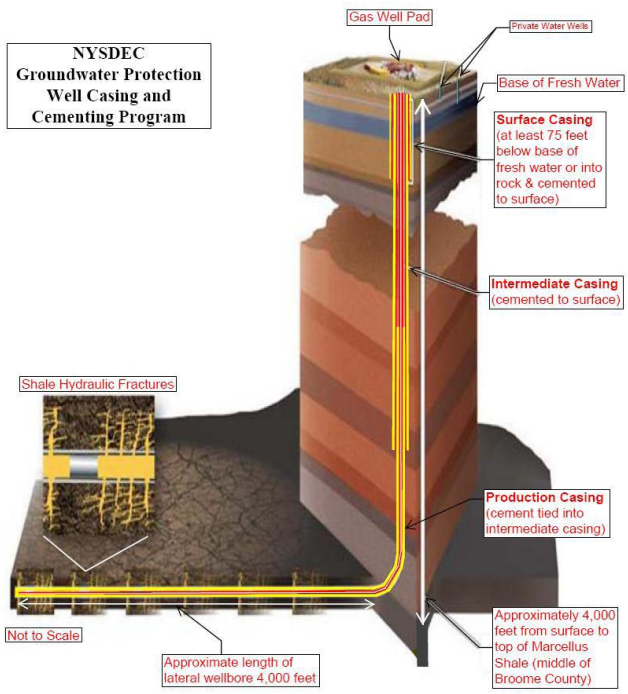
For example, in 2010 the BC Oil & Gas Commission issued a safety advisory on the risks of fracture treatments intersecting adjacent wells. The advisory specifically notified industry that:

> *A large kick was recently taken on a well being horizontally drilled for unconventional gas production in the Montney formation**. The kick was caused by a fracturing operation being conducted on an adjacent horizontal well. Fracture sand was circulated from the drilling wellbore, which was 670m [~2200'] from the wellbore undergoing the fracturing operation.** [emphasis added].*[135]

Additionally, the advisory reported 18 known fracture communication incidents in B.C. and one in Western Alberta: five incidents of fracture stimulation communicating with an adjacent well; three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids; 10 incidents of fracture stimulations communicating into adjacent producing wells, and one incident of fracture stimulations communication into an adjacent leg on the same well for a multi-lateral well. Therefore fracture stimulations communication with adjacent wells is a known and reasonably foreseeable risk.

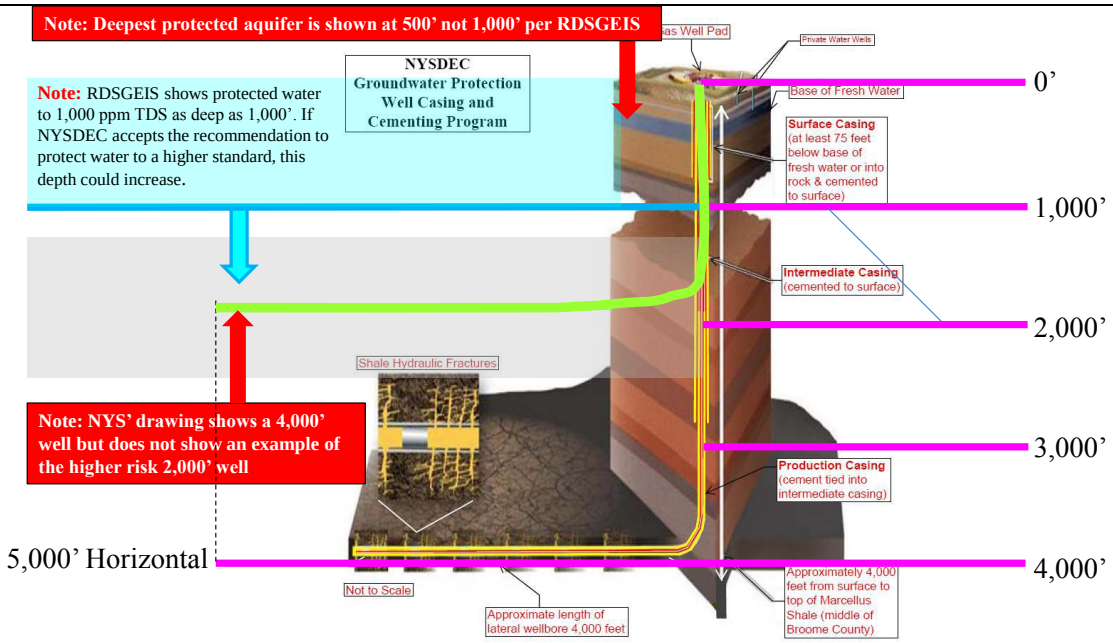
The 2011 RDSGEIS includes a wellbore schematic used in presentations given by the NYSDEC Commissioner. This wellbore schematic, shown below, depicts an example Marcellus Shale well. In the example the base of freshwater is at 500', the well is drilled to a depth of 4,000', and the horizontal length of the well is 4,000'.

[135] BC Oil & Gas Commission, Safety Advisory 2010-03, Communication During Fracture Stimulation, May 20, 2010.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing showing a 500' freshwater depth and a 4,000' HVHF well.

The drawing does not represent the highest risk wells proposed in the 2011 RDSGEIS. The highest risk wells allowed under the 2011 RDSGEIS would be drilled into a thin section of the Marcellus Shale at a 2,000' depth, with protected water located above at 1,000'. Below is an annotated version of this wellbore schematic, prepared by HCLLC, showing the higher risk wells proposed under the RDSGEIS.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing was annotated by HCLLC to show a HVHF well constructed at 2,000' depth, the base of freshwater at least at 1,000' and a theoretical uncertainty zone associated with vertical and horizontal fracture propagation at 2,000' depth.

As explained in Chapter 9 of this report , if a HVHF treatment intersects with a nearby improperly abandoned well, the potential exists for the improperly abandoned well to become a vertical conduit, and therefore transfer hydraulic fluid and mobilized gas to protected aquifers. Additionally, the pollution risk posed by possible HVHF intersections is not limited to improperly abandoned wells; existing wells that were poorly designed and constructed could also pose a risk.

Physics dictate that fractures form perpendicular to the direction of the least amount of stress. Vertical fracture height will decrease with depth, and horizontal fracture length will increase.

NYSDEC proposes that operators identify wells within a mile radius around the surface location of a HVHF well, to identify wells that might be at risk of intersection with HVHF treatments.[136] However, NYSDEC does not provide technical data to support a mile radius. The 2011 RDSGEIS does not specify a maximum horizontal drilling length. Although NYSDEC's spacing rules may impose some limitation on this length, limitations are not clearly explained in the RDSGEIS.

The RDSGEIS should identify the maximum horizontal fracture propagation distance that could occur in a shallow well to ensure that HVHF treatments do not intersect existing wellbores. This should be included in the SGEIS. Limits on horizontal drilling section lengths and HVHF job size, including a safety zone around each HVHF well, should also be established.

Recommendation No. 34: The SGEIS should provide a basis for the maximum horizontal well drilling limit. The SGEIS should also explain how the operator will verify that the maximum horizontal well drilling limit, plus the maximum predicted horizontal fracture length, will avoid nearby well intersection.

The most logical way forward is to begin by limiting development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers. Once accurate, field-calibrated 3D reservoir simulation models are available for NYS, development can then move to shallower intervals, as long as technical data shows that treatments will remain in zone.

Recommendation No. 35: The SGEIS should technically justify vertical and horizontal HVHF treatment offsets. Proposed offsets should be supported by hydraulic fracture modeling. Modeling should reflect the maximum HVHF job designs allowed in NYS and shale reservoir characteristics. NYSDEC should provide public access to the scientific data and hydraulic fracture models it uses to develop vertical and horizontal offsets for the purposes of the SGEIS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4000') will maximize data collection, affording access to all overlying intervals. Core samples, well logs, and pressure transient data can be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers, and geologic barriers that will limit fracture propagation. Initially, smaller fracture treatments should be used as tests. These treatments can be increased in size over time, if data support the conclusion that large fracture treatments can remain in zone. As data are collected, and 3D reservoir models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals.

NYSDEC's recommendation to move forward with shale gas development, absent additional engineering data and hydraulic fracture models, is technically unsupported and in direct conflict with the information cited in its 2009 DSGEIS and 2011 RDSGEIS, as well as its own consultants' recommendations.

[136] 2011 NYSDEC, RDSGEIS, Page 6-56.

Recommendation No. 36: The SGEIS should include a more thorough examination of hydraulic fracture modeling. The SGEIS and NYCRR should require the operator to:

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

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

(c) Maintain and run hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone;

(d) Collect and carefully analyze data from HVHF treatments to optimize future HVHF treatments;

(e) Initially complete HVHF treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience before proceeding to shallower zones (e.g. 4000' deep and 150' thick, progressively moving shallower as more NYS site-specific information is collected); and

(f) Conduct post-fracture analysis, and provide that analysis to NYS to demonstrate that the HVHF treatment was safely implemented.

NYCRR Proposed Revisions: There are no proposed revisions in the NYCRR. As proposed, the NYCRR do not require operators to:

(a) Submit a HVHF designs to NYS;

(b) Estimate the vertical and horizontal fracture length;

(c) Provide engineering analysis and run HVHF modeling;

(d) Monitor HVHF performance to ensure that HVHF design and actual implementation in the field match; and

(e) Notify NYSDEC if the actual vertical and/or horizontal fracture length greatly exceeds the job design, such that risk may be present to the environment.

11. Hydraulic Fracture Treatment Additive Limitations

Background: In 2009, HCLLC recommended that NYS regulations identify fracture treatment additives that are protective of human health and the environment. HCLLC also recommended that the NYCRR include a list of prohibited chemical additives.

2011 RDSGEIS: The 2011 RDSGEIS includes improvements in the handling and storage of HVHF chemicals by requiring chemicals to be stored in suitable containers placed in secondary containment. Additionally, NYSDEC encourages operators to select the lowest toxicity chemicals. However, neither the 2011 RDSGEIS nor the proposed NYCRR amendments establish a prohibited chemical list, nor do they **require** an operator to use the lowest toxicity chemicals. Instead, the 2011 RDSGEIS requires only that the operator evaluate alternative products. Ultimately, the operator is allowed to select the final chemicals used with no firm evaluation criteria listed in the NYCRR to rule out harmful chemicals.

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.3(c)(1)(v) require only that the operator provide:

> *Documentation that proposed chemical additives exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment than available alternatives; or documentation that available alternative products are not equally effective or feasible.*

The proposed regulation requires the operator to examine chemicals that "exhibit reduced aquatic toxicity" and a "lower risk to water resources," but the NYCRR does not provide specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk.

The 2011 RDSGEIS guides the operator to conduct a five-part analysis:

> *The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system, and (5) feasibility of implementing the alternative.*[137]

However the 2011 RDSGEIS does not instruct the operator on what is required if any part of the five-part analysis has an unacceptable outcome, nor does the NYCRR. For example, if an operator proposes a chemical additive that is known to impact the environment and be persistent if it remains in the environment, but the operator proposes no other alternative, or states that this is the only chemical that will be effective for its planned job, neither the RDSGEIS or the NYCRR prohibit the operator from using this chemical even if it is harmful.

As proposed, the NYCRR would still allow the use of a highly toxic chemical, as long as it was slightly less toxic than the most toxic chemical available. This is not best practice. Best practice would be to use the chemical with the lowest impact and risk, not just a slightly improved risk. Best practice would also be for NYS to develop a list of prohibited chemicals that pose an unacceptable risk to human health and the environment.

[137] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS concludes that it is not possible for hydraulic fracturing to contaminate groundwater, erroneously assuming that all wells will be flawlessly constructed and operated, and that no human error is possible that would put hydraulic fracturing additives in contact with groundwater, with the exception of a potential surface spill. The 2011 RDSGEIS concludes:

> *The regulatory discussion in Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explain why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact.*[138]

The 2011 RDSGEIS should be revised to clarify that groundwater contamination by hydraulic fracturing fluids is a reasonably foreseeable impact that requires mitigation. Well construction failures, engineering design flaws, human error, mechanical malfunctions, and chemical spills all are reasonably foreseeable events, and have occurred at Marcellus Shale operations in Pennsylvania.[139] Additionally, Dr. Myers identifies the potential long-term contaminant transport through conductive faults, natural fractures, and advective transport.[140]

Groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[141] PADEP inspectors *"…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County.*"[142] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[143]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[144]

In May 2011, PADEP fined Chesapeake Energy Corporation $1,088,000 for violations related to natural gas drilling activities that contaminated private water supplies in Bradford County. PADEP issued a news release reporting:

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[138] 2011 NYSDEC, RDSGEIS, Page 8-29.

[139] DEP Investigating Lycoming County Fracking Fluid Spill at XTO Energy Marcellus Well, November 22, 2010, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/

14287?id=15315&typeid=1

[140] Dr. Tom Myers, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

[141] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[142] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[143] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[144] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

> *DEP determined that because of improper well casing and cementing in shallow zones, natural gas from non-shale shallow gas formations had experienced localized migration into groundwater and contaminated 16 families' drinking water supplies.*[145]

If HVHF treatments are conducted in poorly constructed wells, there exists a potential for groundwater contamination. Therefore, as NYSDEC recommends, well construction must be robust, and the use of safe HVHF treatment additives provides any extra layer of protection in the event that human error or mechanical malfunction create a pathway for such additives to reach groundwater. Reducing the toxicity of hydraulic fracturing additives by listing prohibited additives mitigates the impact of both surface and groundwater pollution if it occurs.

Recommendation No. 37: NYSDEC should develop a list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2009 DSGEIS Section 5.3[146] stated that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reported partial compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provided lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 described the potential health impacts of categories of chemicals. Yet the 2009 DSGEIS did not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not. This problem persists in the 2011 RDSGEIS.

Chapter 5 of the 2011 RDSGEIS explains that NYSDOH reviewed information on 322 unique chemicals present in 235 products proposed for hydraulic fracturing of shale formations in New York and categorized them into chemical classes, but did not develop any recommendations for prohibiting specific HF additives. The 2011 RDSGEIS merely concludes that the 322 unique chemicals studied did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS.[147] This conclusion has little significance, since the 1992 GEIS did not establish any criteria for limiting or prohibiting HF chemical additives (i.e., for mitigating potential significant adverse impacts from exposure to these additives). For example, Dr. Miller points out that acrylonitrile and acrylamide are listed, and known to be carcinogenic and quite toxic, but fairly short lived in an aqueous environment.[148] As proposed, NYSDEC would allow these carcinogenic, toxic chemicals to be used, unless industry proposes a less-harmful chemical. The appropriate step for NYS would be to add acrylonitrile and acrylamide, among other chemical that pose a risk to human health or the environment, to the list of prohibited chemicals in NYS.

[145] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[146] 2009 NYSDEC, DSGEIS, Page 5-34.

[147] 2011 NYSDEC, RDSGEIS, Page 8-29.

[148] Dr. Glenn Miller, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

Although the percentage of hydraulic fracturing fluid that is composed of chemicals may be small—typically 0.5 to 2 percent of the total volume required for a Marcellus Shale hydraulic fracture stimulation—the absolute volume of chemicals used is very large. A typical Marcellus Shale well may require the use of more than five million gallons of freshwater for drilling and hydraulic fracturing. A five million gallon hydraulic fracture treatment would require approximately 25,000 to 100,000 gallons of hydraulic fracturing chemicals per well at a chemical additive dosage of 0.5 to 2 percent. Some of these chemicals are toxic, including known or possible human carcinogens, chemicals regulated under the Safe Drinking Water Act due to their risks to human health, and chemicals regulated under the Clean Air Act as hazardous air pollutants.[149]

Recommendation No. 38: The SGEIS should do more than just list chemicals proposed by industry for HVHF operations and describe their toxicity; the SGEIS should identify chemicals that should be prohibited or used with limitations to protect human health and the environment.

Additionally, the 2011 RDSGEIS includes a process for reviewing chemicals proposed by industry that appears to have little value or scientific rigor.

> *For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5.*[150]

Figures 5.3, 5.4, and 5.5 in the 2011 RDSGEIS are merely pie charts showing example compositions from previous Fayetteville and Marcellus Shale HVHF jobs. The 2011 RDSGEIS does not include a scientific analysis of the proposed HVHF compositions to verify if these mixtures are optimal. Therefore, there is little scientific value in having NYSDEC staff compare an operator's proposed HVHF composition to these figures, because NYSDEC has not even completed the fundamental scientific analysis to verify whether these proposed treatment compositions are protective of human health and the environment and whether the figures are a suitable yardstick.

The 2011 RDSGEIS proposes to require industry to submit a Material Safety Data Sheet (MSDS) for every new product that is not currently listed by NYSDEC in Chapter 5 of the 2011 RDSGEIS. NYSDEC explains that the MSDS will provide it with more information on the proposed chemical, but does not institute a plan for taking action to limit or prohibit hazardous chemical use based on a review of that MSDS. Instead, the 2011 RDSGEIS appears to propose that NYSDEC will just collect MSDS information and take no action, other than to accept the chemicals selected by the operator and add the MSDS to NYSDEC's file system.

> *The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.*[151]

[149] United States House of Representatives, Committee on Energy and Commerce, Minority Staff, Chemicals Used in Hydraulic Fracturing, April 2011.

[150] 2011 NYSDEC, RDSGEIS, Page 8-30.

[151] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS goes on to say that NYSDEC staff will verify, by reviewing the well completion form, that the chemicals proposed by industry in a permit application (with no limitations or prohibitions by NYSDEC) were actually the same chemicals used on the HVHF job.

> *In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of materials and volumes of materials utilized, on the well completion report which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.*[152]

The proposed review process holds little scientific or audit value, since NYSDEC is not limiting chemicals in the initial application. It is insufficient to bind industry to use specific chemicals at the tail end of the permitting process, when industry can propose any chemical for use on the front-end.

However, the proposed chemical audit review process would have great value if NYSDEC limited or prohibited chemical use in the initial application. In that case, a post-HVHF review process would be valuable to verify that prohibited chemicals were not used.

There are several international models in place that NYSDEC could consider using to develop a prohibited chemical list, or to develop an approved list of chemical, or both. Below is a short summary of three models that could be considered: (1) the Oslo-Paris Convention (OSPAR) list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk (PLONOR) for the oil and gas industry); (2) Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands; and (3) the Norwegian Pollution Control Authority chemical coding system for the oil and gas industry. These governmental entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive effects.

OSPAR PLONOR: Certain European governmental entities have developed a list of environmentally friendly chemicals. Under the Oslo-Paris Convention (OSPAR)[153] a list of chemicals that were considered to Pose Little Or No Risk (PLONOR) to the marine environment was developed for use in drilling and stimulation treatments. The PLONOR list was initially developed in early 2000 and has been amended several times to add and de-list chemicals. The PLONOR list has been very effective in reducing chemical pollution from offshore operations, and use of the PLONOR list has expanded to onshore oil and gas operations and to other industrial sectors. HCLCC is not recommending that NYS adopt the PLONOR list without review; instead, HCLLC is recommending that NYSDEC consider a process similar to OSPAR's system to develop a list of hydraulic fracturing treatment additives that would pose little or no risk to human health or the environment if the chemicals spilled, leaked, or were improperly disposed, or, in the alternative, consider developing a list of chemicals to be prohibited from use in hydraulic fracturing operations.

[152] 2011 NYSDEC, RDSGEIS, Page 8-31.

[153] The Convention for the Protection of the Marine Environment of the North-East Atlantic (the "OSPAR Convention") was opened for signature at the Ministerial Meeting of the former Oslo and Paris Commissions in Paris on 22 September 1992. The Convention entered into force on 25 March 1998. It has been ratified by Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, Netherlands, Norway, Portugal, Sweden, Switzerland and the United Kingdom and approved by the European Community and Spain.

The OSPAR process is straight forward: the establishment of criteria for inclusion of substances on the PLONOR list. Industry has the burden of proof to provide scientific and technical data to support listing of a chemical as PLONOR—i.e., industry must prove the chemical poses little or no risk. The OSPAR Commission reviews the data and makes the final listing determination. The Commission also can remove chemicals from the PLONOR list if new information comes to light warranting a de-listing. A current list of PLONOR chemicals can be found at the OSPAR website.[154]

C-NLOPB Guidelines: The Canada-Newfoundland and Labrador Offshore Petroleum Board has developed guidelines that industry must follow to select less harmful chemicals used in their offshore oil and gas operations.[155] Industry operators must demonstrate that they have incorporated a chemical selection process in their management system that conforms to the guidelines, and the Board has the ability to audit industry compliance. The guidelines are reviewed at least once every five years to ensure that gains in scientific and technical knowledge are incorporated, and more frequent reviews may be initiated if significant risks are identified. The C-NLOPB Guidelines rely in part on the PLONOR list, but also establish specific requirements for hazard and risk assessment.

The Norwegian Pollution Control Authority has developed a chemical coding system to prohibit use of harmful and toxic chemicals in the Norwegian petroleum industry. The Norwegian Pollution Control Authority system categorizes chemicals by color, using the colors: black, red, yellow and green. Black chemicals are the most hazardous, followed by red, then yellow. Green chemicals are those listed on the PLONOR list.

Black: chemicals on the OSPAR List of Chemicals for Priority Action, chemicals on the Norwegian Pollution Control Authority prioritized list (White Paper No. 21 (2004-2005)), and chemicals in the following categories, characterized by certain ecotoxicological properties:

- Substances that have both a low biodegradability (BOD_{28}<20%) and a high bioaccumulation potential (log P_{OW}•5);
- Substances that have both a low biodegradability (BOD_{28}<20%) and a high acute toxicity (EC_{50} or LC_{50}•10 mg/l); and
- Substances that are detrimental in a mutagenic or reproductive way.

Red: chemicals in the following categories, characterized by certain ecotoxicological properties:

- Inorganic substances that are acutely toxic (EC_{50} or LC_{50}•1 mg/l);
- Organic substances with a low biodegradability (BOD_{28}<20%);
- Substances that meet two of the three following criteria:
  - Biodegradability equivalent to BOD_{28}<60%;
  - Bioaccumulation potential equivalent to log P_{OW}•3 and molecular weight < 700; or
  - Acute toxicity of EC_{50} or LC_{50}•10 mg/l.[156]

[154] OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic, OSPAR List of Substances/Preparations Used and Discharged Offshore Which Are Considered to Pose Little or No Risk to the Environment (PLONOR), Reference Number: 2004-10, 2008 Update, available at: http://www.klif.no/arbeidsomr/petroleum/dokumenter/plonor2008.pdf

[155] The Canada-Newfoundland and Labrador Offshore Petroleum Board, Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands, April 2009, available at http://publications.gc.ca/collections/collection_2009/one-neb/NE23-151-2009E.pdf.

[156] Regulations Relating to Conduct of Activities in the Petroleum Activities (The Activities Regulations), § 56b. The latest update of this list can be found on OSPAR's website under the Offshore Oil and Gas Industry, Decisions, Recommendations and other Agreements.

Green: chemicals on the OSPAR PLONOR list (chemicals considered to Pose Little Or No Risk to the marine environment).

Yellow: chemicals that are not categorized as Green, Black or Red.

Recommendation No. 39: The SGEIS and the NYCRR should include a more rigorous technical and scientific review process to examine newly proposed fracture treatment additives to ensure they are protective of human health and the environment. In addition to a list of prohibited chemicals, NYSDEC should develop a list of recommended/approved fracture treatment additives that have been scientifically and technically reviewed by NYSDEC and NYSDOH and confirmed to pose little or no risk to human health or the environment. This list could be provided to industry for immediate use and would provide industry with a simplified list of chemicals that have already been determined to pose the least risk.

Any chemical not found on this list, or on the list of prohibited chemicals, could be proposed by industry for future use, but would be subject to an in-depth scientific and technical justification and risk assessment review process before being added to the approved chemical list for NYS.

No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment. Industry should bear the burden of proof of demonstrating to NYSDEC and NYSDOH that the chemical is safe. The technical and scientific review and approval process to examine newly proposed fracture treatment additives should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This more rigorous technical and scientific review process should apply to all hydraulic fracture treatments, not just HVHF treatments.

12. Drilling Mud Composition and Disposal

Background: In 2009, HCLLC recommended that the NYCRR be revised to: acknowledge and mitigate drilling mud pollution impacts; minimize drilling waste generation; limit heavy metal and NORM content; and establish best practices for the collection, treatment and disposal of drilling waste.

NYCRR Proposed Revisions: NYSDEC proactively responded to scientific and technical information provided through the public input process, revising the NYCRR to recognize that drilling muds are polluting fluids. NYSDEC removed the existing sentence at 6 NYCRR § 554.1(c)(1) that says "drilling muds are not considered to be polluting fluids." This is an important and positive change in the regulations.

However, additional work is still needed in the proposed amendments to the NYCRR to define what types of drilling muds should be used at various depths in constructing a well. NYCRR should also be amended to include best practices for how those drilling muds should be properly handled and disposed.

In January 2011, NYS consultant, Alpha Geoscience complimented HCLLC for its recommendations on drilling mud composition and disposal and agreed that additional mitigation was warranted. Alpha Geoscience wrote: [157]

> *Harvey Consulting has commented on the need for regulation revisions to specifically address drilling mud and drilling waste. The report states "New York State regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM (Naturally Occurring Radioactive Material) content, and establish best practices for collection, treatment and disposal of drilling waste.*
>
> *Current NYS regulation 6 NYCRR §554.1(c)(1) states that drilling muds are not considered polluting fluids. The 1992 GEIS allows drill cuttings to be buried onsite, and the dSGEIS does not address the potential impact. Drilling muds commonly contain barite which contains mercury (1-10 ppm) (www.fossil.energy.gov) and may also contain cadmium. NYSDEC has not set limits on the heavy metal content of drilling mud, and New York State regulations do not address how to dispose of drill cuttings containing NORM.*
>
> *Harvey Consulting's recommended best management practice for most applications includes a combination of waste minimization, using low impact additives, collecting waste in a closed-loop system, pumping waste to a cuttings reinjection unit, and disposing the waste into a disposal well by deep well injection. Harvey Consulting suggests NYSDEC should thoroughly analyze each situation and location to develop the best site-specific best management practices.*
>
> *Harvey Consulting's comments concerning the composition and handling of drilling mud and drilling waste appear to have some merit. Per 6 NYCRR §554.1 (C)(1) drilling muds are not considered polluting fluids, however the presence of mercury and cadmium in barite composed drilling muds may be cause for concern given the quantity of drilling mud that would be required to drill each well.*

[157] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 7-9.

> *NYSDEC regulations do not clearly define the treatment or disposal of drilling waste and any best management practices concerning their handling, and/or recycling are not clearly outlined in the dSGEIS as documented by Harvey Consulting. Section 5.13 of the dSGEIS covers waste disposal, however it is general in its scope and does not outline any best management practices concerning the recycling, treatment, or disposal of drilling waste.*
>
> *Harvey Consulting's review recommends that the dSGEIS include best management practices concerning the type and handling of drilling mud and the subsequent waste byproducts. It suggests that NYSDEC should determine which drilling fluid composition and disposal methods are best practices for various scenarios.* ***Alpha agrees that the proposed measures seem reasonable and would serve to protect the public, environment, and the drilling applicant*** *[emphasis added].*

2011 RDSGEIS: The 2011 RDSGEIS explains that drilling operators propose to drill through protected groundwater zones using compressed air or Water-Based Muds (WBM).

> *The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid.*[158]

The use of compressed air and WBM for drilling though the protected groundwater zones is best practice, as long as NYCRR also sets limits on the type of additives that can be mixed in the WBM formulation. WBM additives used when drilling through the protected groundwater zones should be non-toxic.

The 2011 RDSGEIS' use of the term "typically" indicates that use of compressed air and WBM for drilling though the protected groundwater zones may only occur a portion of the time. This is a best practice that should be implemented each time a well is drilled through protected groundwater zones.

While the 2011 RDSGEIS documents industry's position that it "typically" will use compressed air and WBM for the protection of groundwater, NYSDEC should *require* that practice and ensure that the requirement is codified in NYCRR. The proposed amendments to the NYCRR do not limit the types of drilling muds that can be used while drilling through protected groundwater zones. NYCRR should be revised to clearly prohibit the use of Oil-Based Muds (OBM) and Synthetic-Based Muds (SBM) drilling through protected groundwater zones and to limit additives used in the WBM to those that are non-toxic.

OBM contain diesel fuel or other hydrocarbons. SBM use synthetic oil. SBM are less harmful than OBM, but still contain materials that are toxic, bio-accumulate when discharged into water, and do not bio-degrade. For example, European nations prohibit the discharge of SBM to offshore waters, and prohibit their use when drilling through protected waters.[159] SBM are not approved by USEPA or Department of Energy for discharge offshore because they exceed USEPA's effluent limit guidelines.[160] The 2011 RDSGEIS incorrectly describes SBM as *"food-grade"* and *"environmentally friendly."*[161]

[158] 2011 NYSDEC, RDSGEIS, Page 5-32.

[159] Jonathan Wills, M.A., Ph.D., M.Inst.Pet., for Ekologicheskaya Vahkta Sakhalina, Muddied Waters A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping, May 25, 2000.

[160] http://web.ead.anl.gov/dwm/techdesc/discharge/index.cfm.

[161] 2011 NYSDEC, RDSGEIS, Page 5-32.

Recommendation No. 40: 6 NYCRR § 554.1(c)(1) should be revised to limit the types of drilling muds that can be used while drilling through subsurface formations that contain protected groundwater. Drilling muds should be limited to Water-Based Muds (WBM) or drilling with air. Any additives required for safe drilling through the protected groundwater interval with WBM should be limited to additives that are bio-degradable, are non-toxic, and do not bio-accumulate. The SGEIS should also include this requirement as a mitigating measure.

Neither the 2011 RDSGEIS nor the proposed amendments to the NYCRR instruct the operator on how to properly dispose of drilling fluids. NYCRR requires a disposal plan and that drilling fluids be removed from the drillsite within 45 days; however, 6 NYCRR § 554.1(c)(1) does not provide specific instructions or criteria for acceptable drilling mud disposal plans. This problem was identified by HCLLC in 2009, and is still unresolved.

This problem is magnified in light of new language in the 2011 RDSGEIS that appears to contemplate allowing drilling muds to be spread on non-active agricultural fields and other soils. The 2011 RDSGEIS includes a discussion on proposed Agricultural District requirements. One of the requirements discussed is for "spent drilling muds to be removed from active agricultural fields." [162] The RDSGEIS is silent on provisions for non-active agricultural fields and other soils, and it is unclear what NYSDEC has planned for drilling mud disposal. NYSDEC should clarify its intentions in regards to spreading drilling muds.

The 2011 RDSGEIS correctly notes that drilling mud can be reconditioned and used at more than one well,[163] but it must eventually be disposed. Drilling muds may contain mercury, metals, NORM, oils, and other contaminates. This is especially true for Marcellus Shale operations where naturally occurring radioactive material is present in the shale drill cuttings and mud mixture. Therefore, drilling muds require proper handling and disposal. [164]

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 RDSGEIS is unclear on what NYSDEC has deemed to be the best management practices for handling drilling waste. A recent U.S. Department of Energy review of NYSDEC's 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 [emphasis added]."*[165]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), or established limits on the heavy metal content of drilling mud additives.

Regulations at 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on drilling fluid handling and disposal. Questions that need to be addressed include: Where will drilling waste be taken for treatment and disposal? What tests will be run to characterize the waste stream for proper handling,

[162] 2011 NYSDEC, RDSGEIS, Page 7-145.

[163] 2011 NYSDEC, RDSGEIS, Page 5-32.

[164] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[165] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.

treatment, and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What types of treatments will be completed? What is the ultimate disposal location for the treatment byproducts?

Recommendation No. 41: 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on the best practices for drilling mud handling and disposal. The SGEIS should also provide specific instructions on the best practices for drilling mud handling and disposal as a mitigating measure. See Chapter 13 of this report for additional recommended disposal solutions.

13. Reserve Pit Use & Drill Cuttings Disposal

Background: In 2009, HCLLC recommended that NYSDEC adopt regulations requiring closed-loop tank systems as best practice, instead of the use of temporary reserve pits to handle and store drill muds and cuttings, unless the operator demonstrates that closed-loop tank systems are not technically feasible. Additionally, HCLLC recommended that if temporary reserve pits are used, NYSDEC should adopt regulations that: require impermeable, chemical resistant liner material; limit the types of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements when drilling was completed. HCLLC recommended that cuttings not be buried onsite, and that waste be removed from the drilling location and properly disposed at an approved waste disposal facility capable of handling the quantity and type of waste generated.

HCLLC recommended that NYS consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a properly designed, approved subsurface disposal well. Additionally, HCLLC recommended that if reserve pits are determined to be the only technically feasible option for temporary waste storage, that storage of drilling waste be limited to un-contaminated drill cuttings, drilled using compressed air or water based-muds with non-toxic additives.

2011 RDSGEIS: The 2011 RDSGEIS recommends closed-loop tank systems as best practice in some circumstances, but in other circumstances defaults to the use of reserve pits, without demonstrating that reserve pits are environmentally preferable.

The RDSGEIS requires a closed-loop tank system for horizontal drilling operations in the Marcellus Shale that do not have an acceptable acid rock drainage (ARD) mitigation plan[166] for on-site cuttings burial; and drill cuttings that are coated with Synthetic-Based Muds (SBM) and Oil-Based Muds (OBM). In all other cases, the RDSGEIS proposes the use of reserve pits.

> *The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:*
>
> - *Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and*
> - *cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.* [167]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 56 requires the operator to provide NYSDEC with an acid rock drainage mitigation plan if NYSDEC requests the plan. However, there is no specific criteria established to define what constitutes and acceptable acid rock drainage mitigation plan.

[166] 2011 NYSDEC, RDSGEIS, Page 7-67.

[167] 2011 NYSDEC, RDSGEIS, Page 1-13.

Yet, the USGS recommends against onsite disposal because of the potential risk posed:

> *Onsite burial of drill cuttings at shale-gas development sites, which is allowable under the dSGEIS if oil-based drilling mud is not used, should be carefully considered. According to Lash and Engelder (2008), pyrite is abundant in the high-TOC basal intervals of the Marcellus Shale. Oxidation and leaching of pyritic shale produces and acidic, metals-rich discharge commonly referred to as AMD (Acid Mine Discharge). A multi-horizontal well site will generate 100 to 500 times the volume of AMD-producing pyritic shale cutting than that generated at a single-vertical well site.* ***If these pyritic shale drill cuttings are left onsite, the potential for future surface-water and groundwater contamination is significant – removal and disposal of all cuttings at an approved landfill would be the preferred approach*** *[emphasis added].*[168]

The RDSGEIS proposal to use reserve pits is internally inconsistent with the RDSGEIS' conclusion that closed-loop tank systems are environmentally preferable for the following reasons:

> *Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:*
>
> - *Eliminates the time and expense associated with reserve pit construction and reclamation;*
> - *Reduces the surface disturbance associated with the well pad;*
> - *Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;*
> - *Lowers mud replacement costs by capturing and re-circulating drilling mud;*
> - *Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and*
> - *Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.*[169]

Additionally, the 2011 RDSGEIS explains the environmental risks of reserve pits:

> ***Pit leakage or failure could also involve well fluids****. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. The conclusions regarding pit construction standards and liner specifications presented in the 1992 GEIS were largely based upon the short duration of a pit's use.* ***The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure if engineering controls and other mitigation measures are not sufficient****. Concerns are heightened if on-site pits for*

[168] Testimony of John H. Williams, Ground-Water Specialist, U.S. Geological Survey, The Council of the City of New York Committee on Environmental Protection, Public Hearing, Draft Supplemental Generic Environmental Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and High-Volume Hydraulic Fracturing, October 23, 2009, Page 2.

[169] 2011 NYSDEC, RDSGEIS, Page 5-39.

> *handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad [emphasis added].*[170]
>
> *As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well to the same target depth. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad.* ***The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system****[emphasis added].*[171]

The use of close-loop drilling waste handling system is a best practice. For example, New Mexico requires the use of closed-loop drilling systems.[172]

Recommendation No. 42: The SGEIS and NYCRR should be revised to prohibit reserve pit use for Marcellus Shale drilling operations, and instead require closed-loop tank systems to collect drill cuttings and transport them to waste disposal facilities. NYCRR should make reserve pit use the exception, allowing it only in cases where closed-loop tank systems are determined to be technically infeasible. If reserve pits are determined to be the only technically feasible option, storage of drilling waste should be limited to un-contaminated drill cuttings from the section of the well drilled using compressed air or water based-muds with non-toxic additives. These best practices for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Of even greater concern is the RDSGEIS' proposal to allow drill cuttings to be buried onsite in some cases. Marcellus Shale cuttings contain Naturally Occurring Radioactive Materials (NORM) and are coated with drilling muds, including Water-Based Mud (WBM). The Marcellus Shale is considered a "highly radioactive" shale,[173] and its drill cuttings may require special hazardous waste handling and treatment. While the RDSGEIS proposes to allow on-site burial only of drill cuttings that were created by air drilling or WBM drilling operations, WBM may contain mercury, metals, and other contaminants.[174]

> *The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore,* ***the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site****, at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills [emphasis added].*[175]

[170] 2011 NYSDEC, RDSGEIS, Page 6-16.

[171] 2011 NYSDEC, RDSGEIS, Page 6-65.

[172] New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division, Regulations at Title 19, Chapter 15, Part 17.

[173] Hill, D.G., Lombardi, T.E. and Martin, J.P., Fractured Shale Gas Potential in New York, 2002, p.8.

[174] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[175] 2011 NYSDEC, RDSGEIS, Page 1-13.

The proposed revisions to NYCRR would require the reserve pit liner to be ripped and perforated as part of the onsite burial process (6 NYCRR § 560.7(c)); therefore, contaminated drill cuttings would be in direct contact with soils and surface waters.

While the RDSGEIS generally takes the position that WBM-coated cuttings can be stored in reserve pits and buried onsite, in some cases it waivers. It is not clear what additional limitations may be applied to WBM-coated drill-cuttings disposal. NYSDEC recognizes that onsite burial of chemical additives included in WBM may not be prudent. However, the RDSGEIS does not spell out criteria for determining what types of WBM-coated cuttings may and may not be stored and buried in reserve pits. The RDSGEIS proposes this decision be left to a later NYSDEC consultation process.

An example of how the RDSGEIS deviates from its general position that WBM-coated cuttings can be stored in reserve pits and buried onsite is as follows:

> *Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing* ***<u>require consultation with the Department's Division of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives.</u>*** *Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit [emphasis added].*[176]

This uncertain position about what to do with WBM-coated drill cuttings is perpetuated in the proposed revisions to NYCRR at 6 NYCRR § 560.7(c):

> *Consultation with the department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives.*

All WBM contains chemical additives. NYCRR must be clear on which chemical additives would trigger the use of closed-loop tanks and prohibit drill cuttings burial onsite.

Recommendation No. 43: The SGEIS and NYCRR should be clear about how WBM-coated drill cuttings will be handled and should not leave this unresolved. The standards for handling WBM-coated drill cuttings should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Additionally, it is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drill cuttings, and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system to collect the drill cuttings, because the cuttings can be directly transported to a waste handling facility. The RDSGEIS agrees with the efficiencies gained through closed-loop tank systems, but incongruously does not recommend them in all cases.

[176] 2011 NYSDEC, RDSGEIS, Page 7-67.

> *The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in* ***closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases*** *[emphasis added].*[177]
>
> *The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit….the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.*[178]

NYSDEC's proposal for onsite burial of contaminated drill cuttings becomes even more paradoxical when the RDSGEIS concludes that operators have not proposed onsite burial of drill cuttings.

> ***Operators have not proposed on-site burial of mud-drilled cuttings****, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater [emphasis added].*[179]

A portion of the well drilled will generate cuttings that do not contain NORM. However, as identified in the RDSGEIS, the Marcellus contains NORM and cuttings drilled during this section of the well would require special handling and disposal.

Recommendation No. 44: The SGEIS and NYCRR should prohibit the onsite burial of drill cuttings. If onsite burial is permitted, it should be limited to cuttings that do not have any NORM and are not coated with drill muds containing mercury, heavy metals, and other chemical additives.

Cuttings Reinjection (CRI) Technology, also referred to as "grind-and-inject technology" is commonly used by industry as a best practice to avoid the need for long-term onsite burial of drill cuttings. CRI technology converts drill cuttings into a slurry that can be injected into a subsurface disposal well. CRI also provides a waste disposal method for used drilling mud, because mud can be used in the slurry formulation to reduce supplemental water needs. Currently, NYS does not have sufficient waste disposal wells to handle the anticipated Marcellus Shale drilling waste volume. Either NYS would need to rely on permitted waste handling capacity at wells out of state, or would need to permit and drill wells to meet that need if there are geologically, hydrologically, and otherwise appropriate locations for such wells in NYS.

For example, CRI is commonly used in Alaska as a best practice to avoid use of long-term reserve pit use and surface burial of contaminated drill cuttings. Waste is collected, ground into a slurry, and injected into a subsurface disposal well.[180] If an injection well is not available at a well location, operators have

[177] 2011 NYSDEC, RDSGEIS, Page 5-37.

[178] 2011 NYSDEC, RDSGEIS, Page 5-37.

[179] 2011 NYSDEC, RDSGEIS, Page 6-66.

[180] BP Exploration (Alaska), Inc., ARCO Alaska, Inc. and ConocoPhillips, Inc. have published numerous technical papers on grind and injection technology, and the success of disposal wells as a pollution prevention measure in the SPE trade journals, and at industry conferences.

collected wastes and transported them back to an injection well location. Operators that do not have their own waste handling facilities or disposal wells typically negotiate an agreement with another operator or a service provider to use its disposal facilities. As a result of this best practice implementation in Alaska, DOE reports there are 58 active Class II-D (disposal) wells and six Class I wells in Alaska.[181]

NYS would need to permit construction of a sufficient number of Class I and Class II injection wells to ensure that there was sufficient capacity for the types and amounts of waste generated.

In addition to the environmental mitigation benefit, CRI technology reduces future liability for industry operators, and has been determined to be an environmentally-appropriate method for handling drilling waste containing NORM by both Shell and Chevron.[182]

Halliburton, an industry service provider, agrees that CRI technology makes business and environmental sense as compared to long-term drilling waste burial at the surface.

> *While it is true that new technology comes with a price tag, and much of the technology used in drilling waste management has been introduced in the last 10 years, many technologies now available to operators* ***<u>are clearly cost effective when the entire well construction cost is evaluated</u>****.*
>
> *The cost of making a mistake and having either an expensive remediation project or a potential liability nearly always significantly outweighs the cost of a good preventative drilling waste management program. Further, compliance with current environmental regulations does not always guarantee immunity in the future…*
>
> *Numerous examples exist of industries having to clean up sites that were fully compliant with all regulations at the time the waste was generated and disposed of….*
>
> *The paper demonstrates that the correct application of these technologies combined with a holistic approach to drilling waste management and drilling fluid operations results in a net reduction in well construction costs and a reduction in the potential for environmental liability…*
>
> *… environmental compliance (whether internally or externally driven) is not the only reason to utilize these types of technologies and services [emphasis added].*[183]

International operators report favorable economics for eliminating exploration and production waste by deep well injection. For example, a 2001 Advantek International Corp. report concludes:

> *Downhole disposal of mud and cuttings waste through hydraulic fracturing provides a zero discharge solution and eliminates future cleanup liabilities…This downhole disposal technology has shown success <u>in both onshore and offshore drilling operations</u> and is*

[181] Puder, M.G., Bryson, B., Veil, J.A, Argonne National Laboratory, "Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes," Prepared for the U.S. Department of Energy, February 2003, Page 17.

[182] Okorodudu, A., Akinbodunse, A., Linden, L., Chevron Nigeria Ltd, Anwuri, L., Shell Petroleum Development Co. Nigeria Ltd., Irrechukwu, D.O., Zagi, M.M., Nigeria Department of Petroleum Resources, Guerrero, H., M-I Swaco, "Feasibility Study of Cuttings-Injection Operation: A Case Study of the Niger Delta Basin," SPE Paper 98640, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production in Abu Dhabi, U.A.E., April 2006,Page 2.

[183] Browing, K., Seaton, S., Halliburton Fluid Systems, "Drilling Waste Management: Case Histories Demonstrate that Effective Drilling Waste Management Can Reduce Overall Well-Construction Costs," SPE Paper 96775, presented at the 2005 SPE Annual Technical Conference and Exhibition in Dallas Texas, October 2005, Pages 1, 3, & 4

> *becoming a routine disposal option…It also offers favorable economics [emphasis added].*[184]

The U.S. Department of Energy (DOE) also advocates CRI technology:

> *Because wastes are injected deep into the earth below drinking water zones, proper slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods.*[185]

In 1990, the United States passed the Pollution Prevention Act, establishing a national policy that places priority on pollution prevention and specifies that disposal into the environment should only be allowed as a **last resort**:

> *The Congress hereby declares it to be the national policy of the United States that pollution should be prevented or reduced at the source whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and **disposal or other release into the environment should be employed only as a last resort** and should be conducted in an environmentally safe manner[emphasis added]. "*[186]

Additionally, the amount of drill-cutting waste generated can be significant. If CRI technology is not used to dispose of this waste by deep well injection, than surface waste disposal sites will need to be utilized to handle this waste. The RDSGEIS estimates the amount of waste generated for each well:

> *For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.*[187]

Recommendation No. 45: NYS should consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a subsurface disposal well, and work with industry to permit a sufficient number of drilling waste disposal wells to safely meet this need. The use of Cuttings Reinjection (CRI) technology for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR, as an environmentally preferable option to onsite-disposal of drilling waste.

[184] Abou-Sayed, A., SPE, Advantek International, Guo, Q., SPE, Advantek International, "Design Considerations in Drill Cuttings Re-Injection Through Downhole Fracturing," IADC/SPE Paper 72308, Presented at the IADC/SPE Middle East Drilling Technology Meeting in Bahrain, October 2001, Page 1.

[185] Argonne National Laboratory, "An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes," Publication prepared for the U.S. Department of Energy, September 2003, Page 2.

[186] Pollution Prevention Act of 1990, U.S. Code, Title 42, Public Health and Welfare, Chapter 133, Pollution Prevention.

[187] 2011 NYSDEC, RDSGEIS, Page 5-34.

14. HVHF Flowback Surface Impoundments at Drillsite

Background: In 2009, HCLLC recommended that the NYCRR require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in closed-loop tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

2011 RDSGEIS: The 2011 RDSGEIS made excellent revisions that address public concerns and are protective of human health and the environment by clearly prohibiting HVHF flowback waste impoundments at drillsites. The 2011 RDSGEIS recommends the use of closed-loop tank systems at the drillsites for collecting waste before transporting it to a treatment location, or recycling it for use on another well:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[188]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[189]

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.6(c)(27) specifically prohibit HVHF flowback from being directed to or stored in any on-site pit, and require covered watertight tanks to handle flowback at the drillsite. Furthermore, 6 NYCRR § 750-3.4(b) prohibits the issuance of a State Pollutant Discharge Elimination System (SPDES) permit without prior certification that HVHF flowback fluids will be not be directed to or stored in a pit or impoundment. Proposed regulations at 6 NYCRR § 560.3(a)(10)-(11) also require an operator to provide a description of the closed-loop tank system it will use and the number of receiving tanks it will employ for flowback water.

No further recommendations. The RDSGEIS includes the use of closed-loop tank systems, which is best available technology.

[188] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[189] 2011 NYSDEC, RDSGEIS, Page 1-12.

15. HVHF Flowback Centralized Surface Impoundments Off-Drillsite

Background: In 2009, HCLLC recommended that the NYCRR prohibit the use of centralized surface impoundments for HVHF flowback. This recommendation was made because it is best technology to eliminate the use of surface impoundments altogether, rather than gathering HVHF flowback into tanks at the drillsite and then moving it by pipeline or truck to be pumped into a larger open impoundment at a centralized location away from drillsites. If flowback is recycled, it should be trucked or piped from tank–to–tank to another drillsite or used at the same drillsite in a different well.

Eliminating use of centralized surface impoundments prevents: large scale surface disturbance that requires multi-year rehabilitation[190]; the potential for leakage to occur through or around the liner, impacting ground water; and the potential to generate substantial amounts of hazardous air pollution.

A centralized surface impoundment photograph in Pennsylvania is shown below.

Bednarski Centralized Waste Impoundment, Pennsylvania, Site Permit PADEP, 798407

The most serious concern with the use of centralized surface impoundments for HVHF flowback is the amount of hazardous air pollution predicted for these centralized surface impoundments. In 2009, NYSDEC estimated that each centralized impoundment would be a major source of hazardous air pollution, emitting more than 32.5 tons of air toxics per year, and it was unclear if NYSDEC's estimate was even a worst-case estimate:

[190] Surface disturbance is less for temporary tanks than impoundments. Impoundments require surface soil excavation and multi-year rehabilitation. Temporary tanks used at the drillsite use existing gravel space already in place for drilling operations rather that impacting new and additional surface terrain away from the drillsite.

> *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*[191] *[emphasis added].*

USEPA classifies a major source of hazardous air pollution as a source that emits more than 25 tons per year. These centralized impoundments have been sited nearby residential homes and community facilities in other states, increasing the amount of hazardous air pollution exposure to nearby humans, including increased exposure to benzene, a known human carcinogen.

In January 2011, NYS' consultant, Alpha Geoscience, complimented HCLLC for its recommendations on flowback impoundments, and supported improved mitigation:

> *Harvey Consulting has thoroughly documented their discussion of surface flowback impoundments and hazardous air pollutants, citing a professional journal article, technical guidance documents, consultant reports, and NYSDEC documents.* [192]

2011 RDSGEIS: The 2011 RDSGEIS states that centralized flowback impoundments are "not contemplated" by industry.[193]

> ***The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in** reserve pits on the wellpad or in **centralized impoundments**. Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review [emphasis added].*[194]

This industry representation is inconsistent with the actual practice of operators in Pennsylvania. Moreover, neither the RDSGEIS nor the proposed NYCRR amendments prohibit the use of centralized flowback impoundments. This leaves the door open for centralized flowback impoundments to be approved if a site-specific environmental review is conducted.

NYSDEC's requirement to use closed-loop HVHF flowback collection tanks at each drillsite is an efficient collection method, because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. It would not be efficient, or environmentally sound, to collect HVHF waste in a closed-loop flowback tank at the drillsite, and then transfer that waste by temporary piping or truck to a large centralized surface impoundment off of the drillsite location.

Recommendation No. 46: The SGEIS and NYCRR should prohibit the use of centralized surface impoundments for HVHF flowback based on the known impacts examined in the SGEIS process. HVHF flowback waste should be collected at the wellhead and recycled or directly routed to disposal. This prohibition should be described in the SGEIS as a mitigation measure and codified in the NYCRR.

[191] 2009, NYSDEC, DSGEIS, Page 6-56.

[192] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 31.

[193] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15.

[194] 2011 NYSDEC, RDSEGIS, Page 1-2.

If NYSDEC does not prohibit the use of centralized impoundments, the SGEIS should analyze the impacts and propose mitigation to protect public health and the environment. The decision to allow centralized flowback impoundments should not be segmented from the SGEIS just because it is known to create significant impacts. Prohibiting the use of centralized impoundments mitigates that known risk.

16. Repeat HVHF Treatment Life Cycle Impacts

Background: In 2009, HCLLC recommended that the DSGEIS 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. HCLLC pointed out that the 2009 DSGEIS estimated water use and waste volumes based on a single initial fracture treatment and that this approach does not consider the fact that most shale gas wells require multiple fracture treatments.

2011 RDSGEIS: The 2011 RDSGEIS indicates there may be a potential for repeated HVHF treatments over the life of the well.[195] However, the 2011 RDSGEIS does not quantify the number of HVHF treatments possible per well, nor does it estimate the peak or cumulative impact of these HVHF treatments. Therefore the RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several decade long lifecycle.

NYSDEC does acknowledge that, when Marcellus repeat HVHF treatments are conducted, the impact will be equivalent to the initial treatment. However, its impact assessment does not examine the peak or cumulative impacts that may occur:

> *Regardless of how often it occurs, **if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure** [emphasis added].* [196]

For example, NYSDEC estimates 1,600 or more wells to be drilled and completed per year,[197] estimating a 30 year development life cycle,[198] for a total of 48,000 wells. NYSDEC estimates each HVHF treatment to use an average 4,200,000 gallons per well,[199] and that approximately 9-35% of HVHF treatment returns to the well and is produced as waste that requires handling, treatment and/or disposal. [200] A single HVHF treatment in each well, over a thirty year period, could yield a total waste load of 18-71 billion gallons. That waste volume could double or triple if two or three fracture treatments are conducted on each well over a several decade period. Assuming at least two fracture treatments, and possibly three may be implemented, the waste volumes would increase substantially, possibly exceeding 200 billion gallons.

NYSDEC acknowledges the fact that repeated HVHF treatments have been required in the Barnett shale, typically within 5 years from the initial HVHF.[201] However, NYSDEC notes:

> *Marcellus operators with whom the Department has discussed this question have stated their expectation that refracturing will be a rare event.*[202]

[195] 2011 NYSDEC, RDSGEIS, Page 6-275.
[196] 2011 NYSDEC, RDSGEIS, Page 5-99.
[197] 2011 NYSDEC, RDSGEIS, Page 2-1.
[198] 2011 NYSDEC, RDSGEIS, Page 6-6.
[199] 2011 NYSDEC, RDSGEIS, Page 6-10.
[200] 2011 NYSDEC, RDSGEIS, Page 5-99.
[201] 2011 NYSDEC, RDSGEIS, Page 5-98.
[202] 2011 NYSDEC, RDSGEIS, Page 5-98.

The information NYDEC gathered from a few Marcellus operators, that concludes Marcellus shale re-fracturing will be "rare", is inconsistent with industry literature.

For example, in 2010 Range Resource published a Society of Petroleum Engineering technical paper that describes two successful horizontal shale re-fracture re-stimulations and explains that Marcellus re-fracture stimulations will be used:

> *Based on the success of horizontal re-fracs in other shale plays, re-fracture stimulations in the Marcellus will be an excellent option to maximize fracture complexity and increase the total effective fracture network. …These re-fracs can be utilized to soften overall field decline in future years…"*[203]

In 2006, Schlumberger, an Oil & Gas Service Company, published a Society of Petroleum Engineering technical paper describing the benefits of re-fracture re-stimulations to increase hydrocarbon production in wells that were initially fractured and where hydrocarbon production had declined to a point that it was economically attractive to repeat the fracture stimulation procedure in that same well:

> *A successful refracturing treatment is one that creates a fracture having higher fracture conductivity and/or penetrating an area of higher pore pressure than the previous fracture.*[204]

Schlumberger explains that re-fracture re-stimulations are likely in wells that have the following characteristics: low productivity relative to other wells with comparable pay; remaining reserves in place; need for fracture reorientation to improve hydrocarbon production; poorly placed initial fracture treatment (e.g. proppant crushing, or proppant flowback, use of incompatible fluids); and reservoir complexity leading to poor hydrocarbon recovery.

A 2010 Apache Corporation, Society of Petroleum Engineering paper, agrees that re-fracture re-stimulations will play an important role in shale stimulation for some time to come. Apache Corporation explains that re-fracture re-stimulations are being used in shale wells to increase gas production, and to make good wells even better gas producers:

> *Refracs of even good wells increased the recovery and re-established near initial production rate. Increasing stimulated reservoir volume should increase both the IP*[205] *and EUR*[206]*. When new areas of the shale are exposed in a refrac, there should also be a gain in reserves (Warpinski, 2008). Increases in stimulated reservoir volume could be accomplished by opening many of the micro-cracks and laminations within the undisturbed matrix blocks in the initial drainage [area] that were left unstimulated by previous fracturing attempts. Re-opening of natural and hydraulic fractures that had closed due to overburden and confining stress created by depletion would re-establish matrix area contact.*[207]

[203] Curry, M., and Maloney, T., Range Resources Corp., Woodroof, R., and Leonard, R. ProTechnics Division of Core Laboratories, Less Sand May Not Be Enough, Society of Petroleum Engineers Technical Paper, SPE 131783, 2010. Page 12.

[204] Moore, L.P., Ramakrishnan, H,, Schlumberger, Restimulation: Candidate Selection Methodologies and Treatment Optimization, Society of Petroleum Engineers Technical Paper, SPE 102681, 2006. Page 1.

[205] IP= Initial Production.

[206] EUR= Expected Ultimate Recovery.

[207] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

Re-fracture re-stimulation has been used widely in the Barnett Shale. Many technical papers report successful re-fracture re-stimulations in the Barnett Shale where improved HVHF slickwater fractures were used as a second treatment after the initial cross-linked gel fracture treatment. While the Marcellus and Utica Shales in NYS will start with improved HVHF slickwater fracture treatments, these treatment methods will continue to improve over time, and like the Barnett, repeat fracture treatments will be required to improve hydrocarbon performance as new and improved fracture treatment design supplants existing technology. Apache Corporation explains:

> *Fracturing technology for shales is constantly improving and refracs may slowly fade from common use as the frac designs for shale wells are optimized.* ***Until optimal fracs are achieved and production engineering is optimized, however, refracs will have a place in shale stimulation*** *[emphasis added].*[208]

Additionally, NYSDEC acknowledges the benefits of re-fracture treatment:

> *Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary. Refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.* [209]

Recommendation No. 47: The SGEIS should quantify 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. Additionally, the SGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts.

[208] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

[209] 2011 NYSDEC, RDSGEIS, Page 5-98.

17. Air Pollution Control and Monitoring

Air Quality Impact Assessment Modeling Analysis:

In 2009, AKRF's comments on the 2009 DSGEIS (prepared for NRDC) identified a number of shortcomings in the air quality impact assessment modeling analysis. Notably, that emissions from 10 wells per year and simultaneously operating equipment would produce emission impacts that exceed the NAAQS.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantial amount of new modeling work and a number of operational restrictions and limitations to ensure that NAAQS are not violated. While the RDSGEIS has been significantly improved in this area, some problems with the analysis persist, and some new problems have developed.

The following assumptions used in the air quality impact assessment modeling analysis warrant further review and justification:

- The modeling analysis assumes that a maximum of four wells per drillsite will be drilled each year.[210] However, NYS ECL § 23-0501 requires development of all infill drilling within three years of the first well drilled, and the RDSGEIS envisions the Marcellus Shale gas reservoir will be developed from a multi-well pad for a 640-acre spacing unit, with 40-acre spacing. At 40-acre spacing density, 16 wells would need to be drilled in three years to fill a 640-acre unit, meaning that a maximum of 5-6 wells could possibly be drilled per year. This conflicts with the 4 wells per year (12 wells for three years) assumption and would generate more significant air quality impacts than contemplated by the RDSGEIS.
- Gas compositional data used in the modeling analysis was based on Marcellus Shale gas only. There was no analysis of Utica Shale gas or gas from any other low-permeability gas reservoir.[211] Modeling should be based on a reasonable worst case scenario that includes analysis of all shale formations with development potential, not just the Marcellus Shale, if the SGEIS proposes to cover more reservoirs.
- The modeling analysis assumed that there will be no emissions of criteria pollutants from venting. However, the RDSGEIS proposes to allow gas venting of up to 5 MMscf during any consecutive 12-month period, including sour gas, as long as it is vented at least 30 feet in the air. This allowance undermines the assumption that no criteria pollutants would be emitted during venting.
- The modeling analysis assumes only three days of gas flaring per well. However, the RDSGEIS states that flaring can occur for up to a month in some cases.[212] Therefore, the modeling understates the potential emissions from flaring.

[210] 2011 NYSDEC, RDSGEIS, Page 6-104.

[211] 2011 NYSDEC, RDSGEIS, Page 6-115.

[212] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

- The supplemental 24-hour $PM_{2.5}$ model impacts analysis did not evaluate simultaneous operation of equipment operating on the pad. However, other short-term impact assessment assumed simultaneous operation of one well drilling, one well completion and one well flaring, along with operation of the on-site line heater and off-site compressor for the gas production phase for previously-completed wells.[213] Therefore, the 24-hour $PM_{2.5}$ impact modeling is based on inconsistent assumptions.

- To account for the possibility of simultaneous well operations at nearby pads, a simplified sensitivity analysis was performed in the RDSGEIS to determine the potential contribution of an adjacent pad to the modeled impacts.[214] This modeling assumed a single adjacent pad, located one kilometer away (0.62 miles), with identical equipment and emissions as the modeling target pad.

  The RDSGEIS model only examined the potential for two multi-well drillsites, drilling horizontal wells to be located near each other at a distance of 0.62 miles apart. The modeling analysis assumed that only two drillsites would be operating nearby each other, and that drillsite development in an area would occur in a sequential fashion,[215] which is not always the case (especially when there are multiple operators developing an area).

  The modeling analysis did not evaluate the possibility of more than two multi-well drillsite drilling and completion operations adjacent to each other, nor did it evaluate the possibility of multi-well drillsites operating nearby several single well drilling and completion operations drilled on 40 acre spacing. Nor did the analysis examine the possibility that the surface location of multi-well drillsites could be positioned closer than 0.62 miles apart.

  NYS does not require drillsites to be located over the drilling unit, as long as surface siting approval is authorized. Therefore there is a possibility for drillsites to be located closer than 0.62 miles, a possibility of simultaneous operation of more than two drillsites at a time, and a possibility that more significant overlapping ambient air pollution impacts may occur than modeled. Therefore, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. NYSDEC wither needs to examine all possible concurrent operation impacts, or prohibit the possibility.

- Mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal).

  The RDSGEIS assumes that both light and heavy duty trucks will only travel 20-25 miles[216] one way, yet out-of-state treatment and disposal facilities may be located several hundred miles away. For rural operations, it is unlikely that supplies, equipment, specialty contractors, lodging, and other support equipment and personnel will be located within 20-25 miles of the drillsite.

[213] 2011 NYSDEC, RDSGEIS, Page 6-124.

[214] 2011 NYSDEC, RDSGEIS, Page 6-127.

[215] 2011 NYSDEC, RDSGEIS, Page 6-136.

[216] 2011 NYSDEC, RDSGEIS, Page 6-176.

- The modeling analysis assumes that there will be no simultaneous operations of well drilling and completion equipment on a drillsite. There is a permit requirement prohibiting simultaneous operations;[217] however, this requirement is not codified in the proposed revisions to NYCRR.[218]

Recommendation No. 48: The RDSGEIS air quality impact assessment modeling analysis assumptions warrant additional review and justification. Limitations used in the modeling assumption must all be translated into SGEIS as mitigation measures and codified in the NYCRR to ensure the assumed impacts will not be exceeded. This was done in some cases, but not all. In the cases where modeling assumptions used cannot be justified, modeling revisions will be needed to examine impacts and identify required mitigation, or operational limits set.

Air Quality Monitoring Program:

In 2009, AKRF recommended improved air dispersion modeling and a region-wide emissions analysis. In response, NYSDEC completed a significant amount of additional work on the air quality section of the RDSGEIS. A major conclusion from this work was that there is insufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$. As a result of this lack of data, these impacts were not fully quantified by modeling alone. Furthermore, NYSDEC concluded that ambient air quality monitoring program is needed.

While implementation of a ambient air quality monitoring program, is an important improvement in the RDSGEIS, the proposed program needs further definition, a funding commitment, and a formal industry compliance obligation.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a commitment to implement local and regional air quality monitoring:[219]

> ***The Department also developed an air monitoring program to fully address potential for adverse air quality impacts beyond those analyzed in the dSGEIS, which are either not fully known at this time or not verifiable by the assessments to date.*** *The air monitoring plan would help determine and distinguish both the background and drilling related concentrations of pertinent pollutants in the ambient air [emphasis added].*[220]
>
> *The dSGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations do not result in the exceedance of any NAAQS. In addition,* ***the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas*** *[emphasis added].*[221]

[217] 2011 NYSDEC, RDSGEIS, Appendix 10, Attachment A, Condition 2.

[218] 2011 NYSDEC, RDSGEIS, Page 6-115.

[219] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

[220] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 16.

[221] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

Although Section 6.5.4 of the RDSGEIS proposes alternative methods for implementing air quality monitoring, it does not settle on a recommended solution.[222] The RDSGEIS proposes two alternatives: (1) industry-led monitoring with NYSDEC oversight, or (2) NYSDEC monitoring with industry funding. The RDSGEIS identifies NYSDEC monitoring with industry funding as the preferred alternative without making clear how this goal will actually be funded and implemented.

Table 6.24 proposes to: add a single air monitoring trailer and mobile laboratory to monitor ozone, particulate matter, oxides of nitrogen and air toxics; use infrared cameras to monitor gas leaks; and conduct summa canister sampling for BTEX and other VOCs. However, the RDSGEIS does not explain how the addition of a single mobile trailer and lab along with some other intermittent sampling will provide sufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$.

The RDSGEIS did not evaluate the possibility of installing permanent monitoring locations at numerous locations in NYS, with priority in existing non-attainment areas, and areas that will be heavily impacted by shale gas development. Instead, the RDSGEIS only proposes to examine "regional level" monitoring by collecting data at two sites in NYS.[223] This proposal is insufficient because monitoring regional ambient air quality is not possible with the limited data provided by a two-site program, proposed for an unspecified time period.

More information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling.

The obligation to fund the air quality monitoring program needs to be clearly tied to a permit condition requirement—for example, the permit to flare or spud a well should require a contribution to an air quality monitoring fund; such a requirement is not set forth in either Appendix 6 or Appendix 10.

Recommendation No. 49: The SGEIS should include a more rigorous air monitoring program to achieve NYSDEC's goal of regional and local air pollutant impact monitoring. The proposed program should identify: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

The RDSGEIS acknowledges that air monitoring may identify peak or cumulative air pollution impacts that warrant additional emission controls. For example, NYSDEC has identified that:

> *…the consequences of the increased regional NOx and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions,*

[222] 2011 NYSDEC, RDSGEIS, Page 6-180 through 6-184.

[223] 2011 NYSDEC, RDSGEIS, Page 6-181.

> *including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable.*[224]

However, the RDSGEIS does not explain NYSDEC's plan to collect data, identify the potential for air pollutants to exceed the federal, state or local air pollution control standards, or require these additional emission controls in a timely manner before adverse impacts are realized by humans or the surrounding ecosystem.

Recommendation No. 50: The SGEIS should explain NYSDEC's plan to collect data, identify the potential for pollution problems to exceed the federal, state or local air pollution control standards, and the timely installation of additional emission controls, in order to protect against exceedances of pollution control standards, should be required as an SGEIS mitigation measure and codified in the NYCRR.

GHG Impacts Mitigation Plan:

In 2009, HCLLC and AKRF recommended further analysis of Greenhouse Gas (GHG) impacts and mitigation. In response, NYSDEC acknowledged the potential for GHG emissions impacts and the need for mitigation. While such acknowledgement represents a substantial improvement from the 2009 draft, the proposed mitigation needs improvement to ensure the requirements are clear, measureable and enforceable.

The 2011 RDSGEIS: The 2011 RDSGEIS requires a GHG Impacts Mitigation Plan.[225]

> *The Plan must include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of EPA's Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the GHG Reporting Rule.*[226]

The GHG Impacts Mitigation Plan requires the operator to implement a Leak Detection and Repair Program,[227] use Reduced Emission Completions,[228] use EPA Natural Gas STAR program recommendations, and identify other best management practices.

The requirement that a GHG Impacts Mitigation Plan be prepared and include the use of best management practices for GHG control is a step in the right direction; however, given the variety of best management practices under EPA's voluntary Natural Gas STAR program, NYSDEC should require that well operators select and install the controls that will achieve the greatest emissions reductions possible. In addition, such emissions reductions should be made enforceable, as permit conditions or in the NYCRR.

[224] 2011 NYSDEC, RDSGEIS, Page 6-181.

[225] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[226] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[227] See also HCLLC recommendations on LDAR Program in this section of the report.

[228] See also HCLLC recommendations on Reduced Emission Completions in this section of the report.

For example, the Natural Gas STAR Program data shows that it is both technically feasible and economically attractive to use "low-bleed" or "no-bleed pneumatic controllers and plunger lift systems;[229] however, it is not clear whether an operator would be required under the GHG Impacts Mitigation Plan to use this technology, or how NYSDEC would enforce its use if an operator chose not to select it.

NYSDEC should require operators to use Natural Gas STAR Program best management technologies and practices that will optimize emissions reductions.

The RDSGEIS does not make clear whether or how new technologies or practices would be required (e.g. technologies or practices identified by the Natural Gas STAR Program after drillsite construction has been completed). It is not clear if an operator will be required to implement GHG emission controls only at the time of construction, or if there will be an ongoing obligation to implement additional controls as they are identified by the Natural Gas STAR Program and developed.

The plan should include a list of emission controls that will be installed at the time of construction and best management practices, and a process for periodically reviewing new technologies and installing them as new control solutions are developed over time.

Recommendation No. 51: NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions.

The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs.

The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Flare and Venting of Gas Emissions:

In 2009, HCLLC recommended that flaring and venting be limited to the lowest level technically feasible and safe. Reducing gas flaring and venting is widely considered best practice. Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[230] Initially the motive was to conserve hydrocarbon resources to maximize federal and

[229] Older gas wells stop flowing when liquids (water and condensate) accumulate inside the wellbore creating backpressure on the hydrocarbon formation. This will be a future problem in NYS, as gas wells age. Methane gas is emitted when companies open wells to vent gas to the atmosphere to unload wellbore liquids (water and condensate that accumulate in the bottom of the well) in order to resume gas flow. The industry typically refers to this process as "blowing down the well" or a "well blowdown." Eventually, even a well's own gas pressure becomes insufficient to flow accumulated liquids to the surface and the well is either shut-in as uneconomic, or some form of artificial lift (e.g. plunger lifts) is installed to transport the liquids to the surface.

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

state revenue and gas supply. More recently, focus on GHG, VOC and HAPs emission reduction has prompted additional innovation to further reduce flaring and venting.

Flares may be used during well drilling, completion, and testing to 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 in the event of equipment malfunction. During the drilling and completion phase of the first well on a well pad, a gas pipeline might not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply has been found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to which it can be routed. The RDSGEIS proposes to require Reduced Emission Completions for all wells where a pipeline is installed, which will reduce the need to flare or vent gas.

During production operations, 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[231] and gaseous by-product streams[232] that are uneconomical to conserve. Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and pipeline repair.[233]

Best practices for planned[234] flaring and venting during gas production should limit flaring and venting to the smallest amount possible and only for purposes of for safety. Gas should be collected for sale, and used as fuel unless it is proven to be technically and economically unfeasible.

The 2011 RDSGEIS: The 2011 RDSGEIS limits planned gas flaring to flowback operations for wells where a gas sales line has not been installed which is a significant improvement.[235]

However, when flaring or venting does occur, there is the potential for relatively high short-term VOC and CO emission impacts that need to be considered.[236] The RDSGEIS states that industry only plans to flare for a maximum of three days, and NYSDEC only modeled a 3-day impact; yet, the RDSGEIS states that flaring can occur for up to a month (30 days) in some cases. [237]

> ***A flaring period of 3 days was considered for this analysis*** *for the vertical and horizontal wells respectively although* ***the actual period could be*** *either shorter or* ***longer*** *[emphasis added].*[238]

Modeling needs to represent a reasonable worst case scenario. Because only a three day flaring period was considered in the RDSGEIS modeling, planned flaring should be limited to no more than three days.

[231] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

[232] For example: instrument vent gas; stabilizer overheads and process flash gas.

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

[234] There is a difference between planned flaring and emergency flaring. Emergency flaring is conducted to safely route combustible and potentially toxic (e.g. hydrogen sulfide gas) and in most cases cannot be avoided. Planned flaring can be avoided in most cases.

[235] 2011 NYSDEC, RDSGEIS, Page 5-135.

[236] 2011 NYSDEC, RDSGEIS, Page 6-103.

[237] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

[238] 2011 NYSDEC, RDSGEIS, Page 6-197.

Alternatively, modeling analysis should be based on the maximum time period that flaring would be allowed.

Recommendation No. 52: Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. Flaring restrictions should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces HAP, VOC, and GHG emissions.[239] Proposed revisions to 6 NYCRR § 560.6(c)(28) would require that gas be flared whenever technically feasible instead of vented,[240] which is a significant improvement.

The RDSGEIS limits the amount of flaring and venting that is allowed at a drillsite during any consecutive 12-month period; however, it is unclear how the venting (5 MMscf) or flaring (120 MMscf) thresholds were developed, and such thresholds are not listed in the proposed revisions to the NYCRR.

- *During the flowback phase, the **venting of gas** from each well pad will be limited to a maximum of **5 MMscf** during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);*
- *During the flowback phase, **flaring of gas** at each well pad will be limited to a maximum of **120 MMscf** during any consecutive 12-month period [emphasis added].*[241]

Recommendation No. 53: The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting limits, once justified, should be included in the SGEIS as a mitigation measure, codified in the NYCRR, and should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC require that well operators follow best practices for construction and operation of flares used for safety. The RDSGEIS requires self-igniting flares,[242] which is an improvement; however, the RDSGEIS does not require that:

- Flare pilot blowout risk be minimized by installing a reliable flare system;
- Low/intermittent velocity flare streams have sufficient exit velocity or wind guards;
- A reliable ignition system is used;

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

[240] 2011 NYSDEC, RDSGEIS, Page 7-117.

[241] 2011 NYSDEC, RDSGEIS, Page 7-108.

[242] 2011 NYSDEC, RDSGEIS, Page 7-117.

- Liquid carry over and entrainment in the gas flare stream is minimized by ensuring a suitable liquid separation system is in place; or
- Combustion efficiency is maximized by proper control and optimization of flare fuel/air/steam flow rates.

Recommendation No. 54: The SGEIS should require flare systems to be designed in a manner that optimizes reliability, safety, and combustion efficiency, including requirements to: 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. Flare design requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

Reduced Emission Completions:

In 2009, HCLLC recommended the use of Reduced Emission Completions (RECs, also known as "green completions") to control methane and other greenhouse gas (GHG) emissions following HVHF operations. RECs also reduce nitrogen oxide (NO_x) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere.

EPA estimates that, on average, an REC can capture 7,700 Mcf/well workover for an unconventional gas well. If, for example, 2,000 wells are exempted during the first few years of Marcellus Shale gas development in NYS before pipeline infrastructure is more broadly developed, that could result in 15.3 Bcf (6.2 $MMTCO_2e$) of methane gas vented to the atmosphere.

To put the significance of 15.3 Bcf of methane gas (6.2 $MMTCO_2e$) into perspective, it is equivalent to the GHG emissions from:

- Over 1,100,000 passenger vehicles; or
- The electric use of approximately 700,000 homes for one year; or
- 13,000,000 barrels of oil consumed.[243]

The 2011 RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of well-sites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale.

Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued.

[243] EPA Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results

> *Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition,* ***two years after issuance of the first permit for high volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited*** *[emphasis added].*[244]

NYSDEC should not defer the implementation of this known best practice, because it could result in the exemption of several thousand wells from this control technology requirement, leading to unmitigated air quality impacts from uncontrolled venting. HCLLC agrees that RECs are not an option for single exploration wells with no offset wells or pipeline infrastructure nearby. In addition, RECs may not be possible if well pressure is too low. Regulations should make exceptions only for these situations in which emission control is truly infeasible. However, RECs should be required in all other circumstances.

Once an exploration well is drilled and hydrocarbons are located, additional drilling and well completion operations on that same drillsite should be coordinated with gas line installation, enabling RECs for all subsequent wells. High-volume hydraulic fracturing can be completed at any time after a well is drilled and gas is found. The well can be temporarily suspended, and the HVHF be conducted once a gas line is in place. In a newly explored area, it may be reasonable to drill an exploration well, and conduct a HVHF treatment to test gas productivity before drilling additional production wells. However, once a commercial source of gas is identified and tested with that initial exploration well, there is no reason to vent or flare gas using the HVHF flowback process and test wells prior to a gas line installation.

In natural gas fields, gas from the first well is often flared or vented during drilling and completion activities, because natural gas pipelines are typically not installed until it is confirmed that an economical gas supply has been found. However, once a pipeline is installed, subsequent wells drilled on that same pad would be in a position to implement REC techniques.

Operators often point to the lack of pipeline infrastructure as a primary reason REC may not be possible. However, there are also alternatives to piping methane, such as using it onsite to generate power, re-injecting it to improve well performance, or providing it to local residents as an affordable power supply. Therefore, RECs do not need to rely solely on the installation of a nearby pipeline.

RECs are technically feasible and economically attractive, and are a commercially available emission control option. Appendix 25 of the RDSGEIS, Reduced Emission Completions Executive Summary, summarizes the economic benefits, making a clear case for requiring this technology on all NYS wells, with few exceptions. RECs provide an immediate revenue stream by routing gas (methane and gas condensates) to a gas sales line that would otherwise be vented into the atmosphere or flared.. Alternatively, captured gas can be used for fuel, offsetting operating costs, or re-injected to improve well performance. Industry has demonstrated that RECs are both an environmental best practice and profitable.

In addition to being economically attractive for the operator, there are a number of other benefits of RECs:

- The collection of potentially explosive gas vapors, rather than venting them to the atmosphere. This improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability.
- The reduction in emissions, noises, odors, and citizen complaints associated with venting or flaring.
- The reduction in disposal costs, as a result of gas and condensate capture and sale.

[244] 2011 NYSDEC, RDSGEIS, Page 1-116.

- The elimination of the need to secure flare permits and provide flaring notifications.[245]
- The reduction of VOCs and HAPs. Unprocessed natural gas contains VOCs and HAPs, along with methane. Flaring, an alternative control device, can reduce VOCs and HAPs. However, flaring generates NO_X and particulate matter (PM), as well as other combustible byproducts. Many areas with significant oil and gas development have challenges achieving ozone and regional haze standards. Therefore, REC technology is a preferred alternative.
- Wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring, providing improved well cleanup and enhanced well productivity.
- Fewer wells are drilled as more methane is kept in the system and sent to market, thereby reducing a range of environmental impacts.

While some operators report the voluntary use of RECs, many wells in the United States are still drilled without REC. And, even for companies that have announced the use of RECs, it is not clear how extensively RECs are implemented. Thus, many states have put REC requirements into effect.

The commercial availability of REC equipment has become so widespread that it is now required in several states. For instance, Colorado requires RECs on all oil and gas wells unless they are not technically and economically feasible.[246] Fort Worth, Texas requires RECs.[247] Wyoming has required RECs in the Jonah-Pinedale Anticline Development Area (JPAD) since 2007, and more recently, Wyoming has expanded this requirement to all Concentrated Development Areas (CDAs) of oil and gas in the state.[248]

In 2005, EPA estimated that an average of 7,000 Mcf of natural gas can be recovered during each REC.[249] In 2011, EPA increased the emission recovery estimate and created two distinct categories of wells that are major contributors to methane emissions: Unconventional Gas Wells (7,700 Mcf/well workover) and Low Pressure Gas Well Cleanup (1,400 Mcf/well/year). For each unconventional gas well completion, there is an opportunity to generate about $31,000 in gross revenue, creating a very short payout period if the operator invests in its own equipment.[250]

Investment in REC equipment is extremely profitable, with a conservative average investment cost of $10,000 per REC.[251] The payout occurs quickly if a contractor is hired and the operator only pays a per well REC equipment rental charge. As long as the gas that is captured and sold exceeds the equipment rental charge, the payout is immediate.

Oil and gas operators that have a sufficient number of wells to amortize the cost of REC equipment are finding it more economically attractive to invest in their own technology. Most of the companies that have gone this route report a one- to two-year payout, and substantial profitability thereafter, depending on the gas and condensate recovery rate.[252] For smaller operators, it is possible, and maybe more

[245] Flaring is not always practicable near populated areas or areas of high forest fire risk.

[246] Colorado Oil and Gas Conservation Commission, Rule § 805(b)(3)

[247] Fort Worth Texas, Ordinance No. 18449-02-2009.

[248] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2, Permitting Guidance, March 2010.

[249] United States Environmental Protection Agency, Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[250] (7,700 Mcf)($4/Mcf)= $30,800

[251] EPA's Green Completion PRO FACT Sheet No.703 estimates the cost between $1K and $10K; a $10K per completion cost estimate is conservative.

[252] EPA Natural Gas STAR, Green Completions, PRO Fact Sheet No. 703, September 2004.

financially feasible, to rent REC equipment from a contractor. The profitability math is simple. In 2005, the EPA estimated that, on average, 7,000 Mcf/well of natural gas could be captured, yielding a profit of $14K per well, with a payback of less than one year.[253] However, it is important to note that EPA's 2005 profitability calculations were based on lower gas prices ($3/Mcf) than the current market rate ($4+/Mcf). Using the EPA's new 2011 estimate of 7,700 Mcf/well and a gas price of $4/Mcf, each well, on average, has the potential to generate $31,000 in gross revenue. A portion of that revenue stream must be allocated to purchasing or renting the required REC equipment, but unless that cost is greater than $31,000 per well, a REC is a profitable endeavor. Profitability will vary based on the market price for gas and the cost of carrying out the REC.

The EPA has found that RECs are a major contributor to methane reductions on a national scale. In 2008, 50 percent of the EPA's Natural Gas STAR Program's annual total reductions for the oil and gas production sector was attributed to REC s.[254] Therefore, requiring this technology will be very important to NYS' and EPA's GHG emission reduction goals.

Recommendation No. 55: Drilling and well completion operations should be coordinated with gas line installation, enabling RECs for all wells drilled subsequent to the initial exploration well. Alternatively, methane gas should be used onsite to generate power, re-injected to improve well performance, or provided to local residents as an affordable fuel supply. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Wastewater Impoundments:

In 2009, HCLLC pointed out that centralized wastewater impoundments have the potential to be a major source of HAPs—EPA lists facilities that release 10 tons of a single HAP per year as major sources. The 2009 DSGEIS estimated 32.5 tons of methanol[255] per year—more than three times the HAP major source threshold—could be emitted from centralized wastewater impoundments.[256] This large amount of hazardous air pollution was identified as an unmitigated significant impact.

In 2009, HCLLC recommended the use of closed loop collection and tank systems, rather than wastewater impoundments, as a best practice. The 2011 RDSGEIS prohibits the use of wastewater impoundments at the drillsite, requiring closed loop collection and tank systems. This is a substantial improvement. However, the RDSGEIS does not prohibit centralized flowback impoundments at locations

[253] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[254] 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50 percent are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[255] EPA lists methanol as a hazardous air pollutant, but has not yet classified it with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not yet understood. http://www.epa.gov/ttn/atw/hlthef/methanol.html. Testing in rats has yielded skeletal, cardiovascular, urinary system, and central nervous system malformations. 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. In humans, chronic inhalation or oral exposure may result in headaches, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness. Neurological damage, specifically permanent motor dysfunction, may also be a result. The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.

[256] 2009 NYSDEC, DSGEIS, Page 6-57.

away from the drillsite and fails to analyze the impacts of such centralization. This represents impermissible segmentation. It is recommended that centralized flowback impoundments be prohibited, however, if this recommendation is not adopted a new draft should be prepared analyzing the potential impacts posed by the reliance on centralized impoundments to store and treat HVHF wastewater and made available for public comment; such a significant analysis cannot be deferred until future site-specific review.

Despite the RDSGEIS's reliance on representations by industry that centralized flowback impoundments are not contemplated at this time, recent experience in Pennsylvania, and other states, reveals that industry's use of centralized flowback impoundments has become common practice. The RDSGEIS either needs to clearly prohibit the use of centralized flowback impoundments in NYS or analyze the potential environmental impacts, including human health impacts, posed by such use and develop ways to avoid or mitigate such impacts.

While industry may not presently intend to build centralized flowback impoundments in NYS, that could change in the future. Based on the use of centralized flowback impoundments as a common industry practice, this is a reasonably foreseeable impact, and unless prohibited is an unmitigated significant impact.

As proposed, there would be no limitations in place for these types of impoundments:

> ***Since September 2009 industry has provided information that****: (1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and* ***(3) centralized flowback impoundments, which are large volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated*** *[emphasis added].*[257]

Recommendation No. 56: The use of centralized impoundments to collect waste should be prohibited because these impoundments are a major source of air pollution. This prohibition should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

If centralized flowback impoundments are not prohibited, the potential adverse impacts to human health and the environment must be analyzed fully by NYSDEC. Given that the RDSGEIS includes no analysis whatsoever of the impacts of centralized flowback impoundments, a new draft must be prepared and made available for public comment in order to satisfy the requirements of SEQRA; deferring such analysis for later review would constitute impermissible segmentation. Moreover, mitigation measures to address the potential significant impacts must be included in the SGEIS and codified in the NYCRR.

Gas Dehydrators:

In 2009, HCLLC pointed out that gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions.

[257] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15-16, and Page 6-111.

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. These gases are vented to atmosphere unless pollution controls are installed. Best technology for dehydration units includes the installation of flash-tank separators to recover gas pollutants. Alternatively, pollutants can be routed to a vapor collection/destruction unit, or desiccant dehydrators can be used. Desiccant dehydrators have shown to cost less than flash-tank separators, have lower operating and maintenance costs, and control 99% of HAPs.[258]

The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement.

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, requires:

> *The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control device to limit the benzene emissions to one ton/year;* [259]

The 2011 RDSGEIS also requires a GHG impacts mitigation plan[260] that includes an evaluation of EPA Natural Gas STAR Best Practices for methane and other GHG emissions. However, it does not make GHG emission controls for gas dehydrators mandatory.

NYSDEC's requirement to control emissions from all dehydrators emitting more than one ton per year of benzene will result in emission control on a number of NYS dehydration units. However, smaller dehydration units that do not fall under this requirement may still have economical methane emission control opportunities.

In 2011, the EPA estimated that approximately 8 Bcf of methane is emitted from gas dehydration systems annually. Most of this methane is emitted from smaller glycol dehydration units currently fall below federal regulatory thresholds for emission control. That methane could instead be captured for sale or use as fuel.[261] While the EPA requires a number of large glycol dehydrators to install emission controls, under the federal Maximum Achievable Control Technology (MACT) standards at 40 CFR Part 63, Subpart HH, small glycol dehydrators are typically exempt. Many small operating glycol dehydrator units do not have flash tank separators, condensers, electric pumps, or vapor recovery installed.

There are four straightforward solutions readily available to control methane emissions from TEG dehydrator units, including: installing a flash tank separator; optimizing the glycol circulation rate; rerouting the skimmer gas; and installing an electric pump to replace the natural gas driven energy exchange pump.

A typical glycol dehydration system includes the following components:

- **Glycol Contactor**: Wet gas enters the glycol contactor. Glycol removes moisture from the gas by the process of physical absorption. Along with removing moisture, the glycol also absorbs methane,

[258] 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.

[259] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109, and Appendix 10, Attachment A.

[260] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[261] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

VOCs, and HAPs. Dry gas exits the glycol contactor absorption column and is either routed to a pipeline or a gas plant.

The glycol contactor unit plays the primary role in dehydrating gas to pipeline specifications; the rest of the glycol dehydration system is required to convert the now moisture rich glycol back into a lean product that can be re-used to dehydrate more incoming gas. Therefore, the next step in the process is to route the moisture rich glycol to "regenerator" and "reboiler" units.

- **Glycol Regenerator & Reboiler:** Glycol loaded with moisture, methane, VOCs, and HAPs ("rich glycol") exits the bottom of the glycol contactor unit and is routed to the glycol regenerator and reboiler units, where the absorbed components are removed and "lean" glycol is created. If emission controls are not installed, methane, VOCs, HAPs, and water are boiled off and vented to atmosphere from the regenerator and reboiler units.

  One way to limit the amount of methane, VOCs, and HAPs emitted to the atmosphere from the regenerator and reboiler units is to install a flash tank separator.

- **Flash Tank Separator:** The installation of a flash tank separator between the glycol contactor and the glycol regenerator/reboiler units creates a pressure drop in the system, allowing methane and some VOCs and HAPs to flash out of (separate from) the glycol. The amount of pressure drop that can be created is a function of the fuel gas system pressure or compressor suction pressure, because methane gas flashed-off at the flash tank separator is then sent to be used as fuel in the TEG reboiler or compressor engine. Simply put, the pressure can only be dropped to a pressure that still exceeds the fuel gas pressure, allowing the collected methane gas to flow into the fuel system. Flash tank separators typically recover 90 percent of the total methane and approximately 10 to 40 percent of the total VOCs that would otherwise be vented to atmosphere. Methane emissions can also be controlled by taking the simple step of adjusting the rate that glycol is circulated in the system.

  In 2005, the EPA estimated that the installation of a flash tank separator, on average, resulted in 10 Mcfd (3,650 Mcf/yr) of methane gas captured for sale or use as fuel for each TEG dehydrator (typically a 90 percent reduction in methane emissions). And in 2009, the EPA reported that flash tank separators are installed on ***only***: 15 percent of the dehydration units processing less than 1 MMcfd; 40 percent of units processing 1 to 5 MMcfd; and between 65 and 70 percent of units processing more than 5 MMcfd.[262] Therefore, an emission control target still exists, especially for small dehydration units.

  The installation of a flash tank separator also improves the efficiency of downstream components (e.g. condensers) and reduces fuel costs by providing a fuel source to the TEG reboiler or compressor engine.[263]

- **Glycol Recirculation Pump**: Methane emissions are directly proportional to the glycol circulation rate. Circulating glycol at a rate that exceeds the operational need for removing water content from gas unnecessarily increases methane emissions. Glycol circulation rates are typically set at the maximum to account for peak throughput. Gas pressure and flow rate decline over time, requiring the glycol circulation rate to be adjusted to meet operational need. Optimizing the glycol circulation merely requires an engineering assessment and a field operating adjustment. If the glycol dehydration unit includes a condenser, methane emissions can be collected and used for fuel or destroyed, rather than being vented to atmosphere.

  In 2005, the EPA estimated that optimizing the glycol circulation rate could result in a wide range of methane capture from 1 to 100Mcfd (18,250 Mcf/yr using a median estimate of 50 Mcfd). [264]

[262] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

[263] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

- **Condensers**: Some glycol reboilers have condensers to recover natural gas liquids and reduce VOCs and HAPs. However, condensers do not capture methane (because it is a non-condensable gas); therefore, the addition of a condenser does not reduce methane emissions. When condensers are installed, methane gas is typically vented to atmosphere. Alternatively, this methane gas (called "skimmer gas") can be routed to the reboiler firebox or other low-pressure fuel gas systems.[265] In 2005, the EPA estimated that rerouting glycol skimmer gas could result in an average methane capture of 21 Mcfd (7,665 Mcf/yr). [266]
- **Electric Pump vs. Energy-Exchange Pumps:** Historically, gas-assisted glycol pumps have been used. Where there is an electric supply, the gas-assisted glycol pumps can be replaced with an electric pump. Gas-assisted pumps are driven by the expansion of the high-pressure gas entrained in the rich glycol that leaves the contactor, supplemented by the addition of untreated high-pressure wet (methane rich) natural gas. The high-pressure gas drives pneumatic pumps. Much like pneumatically operated valves, pneumatically operated pumps vent methane.

  In 2007, the EPA estimated that between 360 and 36,000 Mcf/yr in methane emission reductions could be achieved by installing an electric pump to replace the natural gas driven glycol energy exchange pump; the wide range in methane emission reductions is a function of the large variation in equipment sizes.[267]

In 2007, EPA estimated the total potential emission reductions at any given glycol dehydration unit is a function of how many emission control solutions are installed. The total may range from 3,700-35,000 Mcf/year ($14.8K-$140K worth of gas leakage). In 2011, EPA estimated 38,000 Mcf/year ($152K).[268] Therefore, controlling methane emissions and other GHG emissions from dehydration units is good business.

However, despite the clear environmental and financial benefits, not all members of the oil and gas industry voluntarily invest in methane control options. Therefore, it is recommended that NYSDEC require operators to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made.

Recommendation No. 57: Natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

[264] The wide range in methane capture opportunity is a function of the dehydrator size, and how efficiently the operator previously optimized the glycol circulation rate.

[265] USEPA Natural Gas STAR, Reroute Glycol Skimmer Gas, PRO Fact Sheet No. 201, 2004.

[266] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[267] EPA Natural Gas STAR, Natural Gas Dehydration, Producers Technology Transfer Workshop, Durango Colorado, September 13, 2007.

[268] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

Diesel Engine Emission Control:

In 2009 AKRF recommended that diesel engines should be Tier 2 or higher. AKRF pointed out that "Tier 0" engines could be used, unless NYSDEC limited engines by certification type. Uncertified engines have extremely high emission rates for criteria pollutants such as particulate matter.

Additionally, AKRF recommended that diesel particle filters be installed on diesel engines to reduce particulate matter that has shown to aggravate respiratory systems and is known to be carcinogenic. More specifically AKRF recommended that all engines with a power output of 50 horsepower or greater be equipped with a diesel particle filter, either by the original engine manufacturer or by retrofit.

The 2011 RDSGEIS, Appendix 10 Proposed Supplementary Permit Conditions for HVHF, addressed most of AKRF's recommendations, by prohibiting Tier 0 engines, requiring Tier 2 engines in most cases, and requiring both Tier 1 and Tier 2 engines to install emission controls. NYSDEC proposes that:

- ***No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines*** *will be used for any activity at the well sites;*
- ***The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF [Continuously Regenerating Diesel Particulate Filters]) and SCR [Selective Catalytic Reduction] controls****. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and*
- ***The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines****. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence [emphasis added].*[269]

NYSDEC estimates that 25% of the engines may be Tier 1 engines, and to ensure compliance with National Ambient Air Quality Standards (NAAQS) it requires the engine to be equipped with both CRDPFs and Selective Catalytic Reduction controls.

While NYSDEC has proposed a number of improvements for diesel engine emission control, the RDSGEIS did not assess whether Tier 1 engines could be eliminated altogether.

Recommendation No. 58: The SGEIS should examine whether it is possible to eliminate Tier 1 engine use. Further examination of AKRF's recommendation to prohibit Tier 1 engine use is warranted.

[269] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109 and Appendix 10, Attachment A, Condition 9-11.

Leak Detection & Repair Program:

In 2009 HCLLC recommended that NYSDEC require Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks. Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs.

Methane gas leaks can occur from numerous locations at gas facilities—valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points—as gas moves through equipment under pressure. These leaks are called "fugitive emissions."

Fugitive emissions from equipment leaks are unintentional losses of methane gas that may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling.[270]

Because methane is a colorless, odorless gas, leaks often go unnoticed. Historically, leak checks were only performed on equipment components when they were first installed, using a soap bubble test or hand held sensor, to ensure the installation was leak tight. After installation leaks were not typically monitored or repaired unless they became a significant safety hazard. For example, a significant gas leak would be repaired if area, building, or employee monitors set off alarms or if olfactory, audible, or visual indicators observed by facility employees identified the leak. Under these circumstances, the leaks had usually become an obvious safety concern. As a result, methane leaks at outdoor facilities and unmanned facilities often went undetected for long periods of time.

Fugitive emission control is a two-part process that includes: (1) a monitoring program to identify leaks and (2) a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.[271]

There are many different monitoring tools that can be used to identify leaks, including electronic gas detectors, acoustic detectors, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, and infrared leak detection. Once leaks are identified, the operator can evaluate what is causing the leak and develop a replacement or repair program to mitigate the leak.

For example, a hand held infrared camera can be used as a screening tool to detect emissions that are not visible to the naked eye. An infrared camera produces images of gas leaks in real-time. [272] It is capable of identifying methane leaks, but cannot quantify the amount of the leak. Infrared cameras produce photos that show methane gas leaks.

Once a leak is identified, and a more quantitative leak flow rate determination is needed, other measurement devices such as Hi-Flow Samplers, Vent-Bag Methods, and Anemometers may be used.[273] Hi-Flow Samplers capture the entire leak, measuring the leak rate directly for leaks up to 10 cubic feet per

[270] USEPA, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009.

[271] Squarek, J. (Canadian Association of Petroleum Producers), Layer, M. (Environment Canada) and Picard, D. (Clearstone Engineering Ltd.), Development of a Best Management Practice in Canada for Controlling Fugitive Emissions at Upstream Oil and Gas Facilities, 2005.

[272] Snider, P., Advanced Well Completion Technology to Reduce Methane Emissions and Use of Infared Cameras for Leak Detection, Global Forum on Flaring and Venting Reduction and Natural Gas Utilisation, 2008.

[273] Heath, M.W., Leak Detection and Quantification of Fugitive Methane Emissions at Natural Gas Facilities, 2009.

minute (cfm), providing leak flow rate and concentration data. [274] Toxic Vapor Analyzers and acoustic leak detection systems are other methods to identify methane leaks.[275]

Fugitive emissions management is an ongoing commitment, not a one-time initiative. The potential for fugitive equipment leaks will increase as facilities age. Successful fugitive emission control plans require trained personnel, emissions testing equipment, and performance tracking systems.

In 2009, the EPA examined the profitability of repairing equipment leaks at oil and gas facilities and found that leak repair is not only an important air pollution control and safety measure, but also is a profitable investment.[276] EPA reports that fugitive emissions control provides numerous benefits including: reduced maintenance costs and downtime, improved process efficiency, a safer work environment, a cleaner environment, and resource conservation.

The 2011 RDSGEIS acknowledges the potential impact of gas leaks, and requires a Leak Detection and Repair Program to be included in the operator's GHG Mitigation Plan.

> *Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the* ***Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would include as part of the operator's greenhouse gas emissions impacts mitigation plan which is required for any well subject to permit issuance under the SGEIS*** *[emphasis added].*[277]

The 2011 RDSGEIS specifies the minimum requirements for a Leak Detection and Repair Program.

> ***The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements****.*
>
> - *There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;*
> - *Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;*
> - *All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves,*

[274] http://www.heathus.com/_hc/index.cfm/about-us/vision

[275] Methane to Markets, Reducing Methane Emissions through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[276] Methane to Markets, Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[277] 2011 NYSDEC, RDSGEIS, Page 7-114 .

vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;

- *For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and*
- *Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt [emphasis added].*[278]

The RDSGEIS proposal to require an LDAR Program is a substantial improvement; however, a few changes to the proposed program are recommended:

- An LDAR inspection should be conducted at well/drillsite start-up, not 30 days after. It is best practice to construct and install equipment and test for leaks prior to operation. Equipment should not be operated for 30 days without completing this minimum standard of care.
- Quarterly testing with an infrared camera (as a screening method) should be required, instead of annual testing, as a minimum standard. If the infrared camera screening indicates a leak, the leak location, if clearly pin pointed, should be repaired. Or additional testing should be conducted using more sophisticated tools (described above) to pin-point the leak location, followed by a repair.
- Testing should include all equipment located on the drillsite. As proposed, the RSGEIS suggests the LDAR Program end at the separator's outlet. Equipment will be located downstream of the separator outlet, and prior to the connection the gas transit line that could potentially leak gas. Therefore, it is recommended that the LDAR Program be implemented for all equipment on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet.

Recommendation No. 59: The proposed LDAR Program should be revised to require: a drillsite LDAR inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the NYCRR, and be required for all natural gas operations, not just HVHF operations.

[278] 2011 NYSDEC, RDSGEIS, Page 7-115 and 7-116.

Cleaner Power and Fuel Supply Options:

In 2009, HCLLC and AKRF recommended that the SGEIS evaluate the use of cleaner engines and fuels.

In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, thus eliminating local diesel exhaust. This alternative would be particularly beneficial where operations are planned near sensitive receptors and in areas that already suffer from high air pollutant loading. Electric engines have the added benefit of quieter operation and less noise impact in urban and suburban settings.

In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel. Natural gas fired engines produce less air pollution that diesel engines. A natural gas supply should be available for all wells drilled on a multi-well drillsite, except the first well. Once the first well is drilled using diesel, subsequent wells can be drilled using the natural gas produced by that well to generate power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use. The use of dual fuel engines would enable switching from diesel to natural gas once it is available.

The use of electric and natural gas engines would result in reduced local pollutant emissions and overall GHG emissions (both grid power and natural gas have a lower carbon footprint than diesel) and generally would have associated cost savings given the reduced fuel transportation and storage needs (e.g. double-wall tanks) and the reduced risk of tank leakage and cleanup associated with the use of fuel gas produced on-site or electric power.

The 2011 RDSGEIS: The 2011 RDSGEIS did not examine cleaner power and fuel supply options. The RDSGEIS only briefly mentioned that electric engines and cleaner fuel options were recommended[279] but disregarded the recommendations as "unlikely to be practically implemented to any extent" due to the remote nature of the drillsites. This analysis is incomplete and fails to consider viable alternatives for mitigating air pollution.

Foremost, electric power is available in all suburban and urban areas of NYS, and is currently located in many rural areas as well to supply power to homes, farms and businesses.

Secondly, the use of natural gas-fired engines on a multi-well drillsite is a commonly used mitigation measure. While diesel engines are often used as the prime mover of power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[280] EnCana, a gas producer, reports that natural gas-fired rigs reduce air pollution by 90% compared to diesel fired rigs.[281] Power can also be supplied to the drilling rig by a natural gas-powered reciprocating turbine that can generate electricity on site.

[279] 2011 NYSDEC, RDSGEIS, Page 6-144.

[280] www.naturalgas.org.

[281] EnCana 2005 Annual Report.

Recommendation No. 60: In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

18. Surface Setbacks from Sensitive Receptors

Background: The 2009 DSGEIS did not propose sufficient safety or quality-of-life surface setbacks from sensitive human and environment resource receptors. This problem persists in the 2011 RDSGEIS. Noise, traffic, odor, air, and water pollution impacts to sensitive receptors will be significant if the small setbacks proposed in the RDSGEIS are adopted.

Surface setbacks should be increased to mitigate significant impacts and to create a safe environment for the affected public. For example:

- Blowouts can eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. These pollutants can then be further transported in the subsurface or on the surface, creating a large area of contamination in a very short amount of time.
- Chemicals, fuels, and explosive charges (e.g. perforating guns) may be located at the drillsite and may pose hazards to the public, in addition to the flammable, explosive, and hazardous gases (e.g. hydrogen sulfide gas, benzene) that are produced from the well and associated equipment.
- The potential radius of impact for explosions, fire, and other industrial hazards should be considered. For example, the city of Forth Worth, Texas uses the International Fire Code as the basis for its minimum 600' setback from Barnett shale gas drilling operations.[282] Whereas, NYCRR only provides for a 100' setback from a home. 6 NYCRR § 553.2.
- High pressure hose leaks can spray industrial fluids off the drilling pad and onto surrounding properties or waters. The radius of contamination will depend on system pressure, shut-down reaction timing, wind speed, and other factors.

For example, in September 2009, 1,300 gallons of well chemicals were leaked during a hydraulic fracture treatment at the Cabot Heitsman 4H well located in Susquehanna Country, Pennsylvania, and flowed into the nearby Steven's Creek located more than 100 feet away, despite protections in place under the operator's required Pennsylvania PPC plan.[283]

Recommendation No. 61: The SGEIS should provide scientific and technical justification for each setback distance proposed to demonstrate how that distance is protective of the nearby sensitive receptor. A hazard identification analysis should be completed to assess the safe distance from human and sensitive environmental receptors to proposed shale gas drilling and HVHF operations. The analysis should assess blowout radius, spill trajectory, explosion hazards, other industrial hazards, fire code compliance, human health, agricultural health, and quality-of-life factors. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

While statewide minimum setbacks to protect human health, provide safe buffers, and protect the environment should be established, both the RDSGEIS and NYCRR should include a provision to allow local communities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics.

[282] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009.

[283] Cabot Oil & Gas Corporation, Engineering Study, for submittal to PADEP, In Response to Order dated September 24, 2009, prepared by URS Corporation for Cabot, October 9, 2009.

Recommendation No. 62: The SGEIS and NYCRR should allow local zoning authorities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics. The ability to improve local setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2011 RDSGEIS: The 2011 RDSGEIS proposes additional setbacks from aquifers, wells, and water bodies for HVHF operations, but does not establish additional setbacks from homes or public buildings.

NYSDEC does not provide scientific or technical justification in the RDSGEIS for the setback distances it has selected. Setbacks ranging from 150' to 2,000' are included in the RDSGEIS without justification for how or why those particular distances were selected or determined to be adequate to protect water resources.

The 2011 RDSGEIS proposes the following setbacks:

- **500' setback from primary and principal aquifers**. However, for principal aquifers, drilling and HVHF operations can occur within that 500' buffer with additional review, and for both primary and principal aquifers the setback distance will be reconsidered in two years in a yet to be determined process.

  Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing).[284]

  For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary.[285]

- **2,000' setback from a public water supply**, unless a shale gas well is located within 1000' of a subsurface water supply designated by the New York City Department of Environmental Protection (NYCDEP). However, these setbacks will be reconsidered in three years in a yet to be determined process.

  The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing).[286]

  The Department proposes that site-specific environmental assessments and SEQRA determinations of significance be required for … any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.[287]

[284] 2011 NYSDEC, RDSGEIS, Page 1-17.
[285] 2011 NYSDEC, RDSGEIS, Page 1-18.
[286] 2011 NYSDEC, RDSGEIS, Page 3-15.
[286] 2011 NYSDEC, RDSGEIS, Page 3-16.
[287] 2011 NYSDEC, RDSGEIS, Page 3-15.

Recommendation No. 63: The process for revising the 500' setback from primary and principal aquifers and the 2,000' setback from a public water supply in two and three years, respectfully, is unclear. NYSDEC should clarify the review process, including an explanation of its plans for public review and comment. NYSDEC should revise its regulations at 6 NYCRR § 617.4(b) to provide that the siting of any oil or gas well within 500' of a primary aquifer or within 2,000 of a public water supply is a Type I action.

- **500' setback from a private water well**.

> *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 500 feet of private drinking water wells or domestic uses springs, unless waived by the owner.*[288]

The RDSGEIS provides no rationale as to why a public water supply would be afforded a 2,000' setback, while a private water well would only be afforded at 500' setback.

Recommendation No. 64: The SGEIS should examine whether waivers to the 500' private water well setback comport with federal law and the requirement to protect Underground Sources of Drinking Water (USDWs). The SGEIS should provide technical justification for any reduction in this setback, and should not allow a private well owner to reduce the setback such that it poses a risk to its water supply, as well as other user in the area. Private land owners should not be allowed to waive setbacks from private water wells and adversely affect the water quality of neighboring wells.

- **150' setback from a stream, storm drain, lake, or pond**.

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[289]

The 150' setback language conflicts with the 2,000' setback language above, because it allows a closer setback from lakes, rivers and streams than from a public water supply. It is not clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback.

On October 3, 2011 Pennsylvania Governor Corbett announced plans to implement the Marcellus Shale Advisory Commission recommendation to increase the setback distance for wells near streams, rivers, ponds and other bodies of water to at least 300'.[290] An increased set back to at least 300' should also be considered by NYS.

[288] 2011 NYSDEC, RDSGEIS, Page 7-76.

[289] 2011 NYSDEC, RDSGEIS, Page 7-76.

[290] Pennsylvania Office of the Governor, News Release, Governor Corbett Announces Plans to Implement Key Recommendations of Marcellus Shale Advisory Commission, October 3, 2011.

Recommendation No. 65: The conflicting language between the 150' setback requirement and 2,000' setback requirement for lakes, rivers, and streams needs to be resolved in both the SGEIS and the NYCRR. As drafted, neither the RDSGEIS nor the NYCRR are clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback. NYSDEC should indicate whether it intends to apply the 150' setback only to surface water resources that are not actual or potential public drinking water supplies. NYSDEC should also explain whether the 150' set back is sufficient to protect those water resources, or whether this setback should be increased. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

- **4,000' setback from NYC and Syracuse watersheds**.

Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000 -foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality.[291]

Recommendation No. 66: The 4,000' setback from NYC and Syracuse watersheds should be added to the proposed regulatory revisions for operations associated with HVHF at 6 NYCRR § 560.4. The SGEIS and NYCRR should also clarify if activities associated with HVHF drilling and completions will be prohibited underneath the watershed as well as on the surface.

NYSDEC has not provided engineering or scientific justification for the setback distances it has selected, other than a brief assessment of the setbacks that are allowed in other states. NYSDEC ultimately selected setbacks that are not as protective as those identified by the agency's consultants. For example, the RDSGEIS, states:

> *The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.*[292]

NYSDEC's consultants collected information that shows a more protective 350' setback is in use in other states; however, NYSDEC concludes that only a 150' setback will be required. This is less than half the distance of the most protective standard found by NYSDEC's consultants, and the 150' setback can be further reduced at NYSDEC's discretion based on a site-specific SEQRA review:

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[293]

[291] 2011 NYSDEC, RDSGEIS, Page 7-56.

[292] 2011 NYSDEC, RDSGEIS, Page 7-76.

[293] 2011 NYSDEC, RDSGEIS, Page 7-76.

Of note, the RDSGEIS does not address setbacks from homes or public buildings. The RDSGEIS merely requires the operator to document the distance from the proposed drilling and HVHF operations to "…any residences, occupied structures or places of assembly within 1,320 feet."[294] However, no new setback is established for homes or public buildings, other than required by current regulations.

NYCRR Proposed Revisions: The new setbacks proposed in the RDSGEIS are codified in regulation at 6 NYCRR §560.4. These setbacks would apply only to wells that undergo HVHF. NYSDEC does not explain why these setbacks would not apply to all oil and gas well drilling in NYS, despite the fact that 6 NYCRR § 553.2 (Well Surface Restrictions) applies to all NYS oil and gas wells. NYSDEC has not justified its limiting of new setback increases to HVHF wells only.

Recommendation No. 67: The setback increases proposed in the RDSGEIS should apply to all oil and gas drilling in NYS and should be codified at 6 NYCRR § 553.2.

The existing NYCRR allows drilling, HVHF operations, and production equipment to be located within 100' from an inhabited private dwelling and within 150' from a public building or area that may be used as a place of "resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic or occupancy by the public." The existing NYCRR also allows drilling, HVHF operations, and production equipment to be located within 50' from a public stream, river, or other body of water. There is no required setback from buildings or structures used for agriculture. 6 NYCRR § 553.2.

The proposed revisions to the NYCRR include 500' setbacks from primary aquifers, 2,000' setbacks from public water supplies, and 500' setbacks from private wells. Proposed 6 NYCRR § 560.4. However, these setbacks apply only to wells that undergo HVHF, and do not apply to all wells that undergo hydraulic fracturing operations in NYS.

NYSDEC's setback analysis does not take into account that directional drilling technology enables wells to be drilled to a bottom-hole location at 3-5 miles[295] away from a wellhead. In directional drilling, it is now common for the horizontal displacement of the bottom hole location to be several times the total vertical depth (TVD) of the well. For example, a well with a vertical depth of 5,000' could have a bottom hole horizontal displacement of 10,000-15,000' from the drill site, or more. A well with a vertical depth of 7,000' could have a bottom hole horizontal displacement of 14,000-21,000' from the drill site, or more. For example, in 1997, BP drilled a well to approximately 5,300' achieving a 33,182' horizontal displacement, meaning the wellhead was located over 6 miles away from the hydrocarbon target.[296] In 1997, a 6-mile horizontal displacement was a great feat; now, extended reach drilling (ERD) is commonplace in the industry, and wells are routinely drilled to hydrocarbon targets miles away from the wellhead.

Given the flexibility afforded by the fact that 640-acre spacing units may vary in shape, from square to rectangular, and that surface drillsites need not be located over the spacing unit, well operators utilizing directional drilling technology have a greater ability to select surface drillsite locations that optimize distance from sensitive public and private resources.

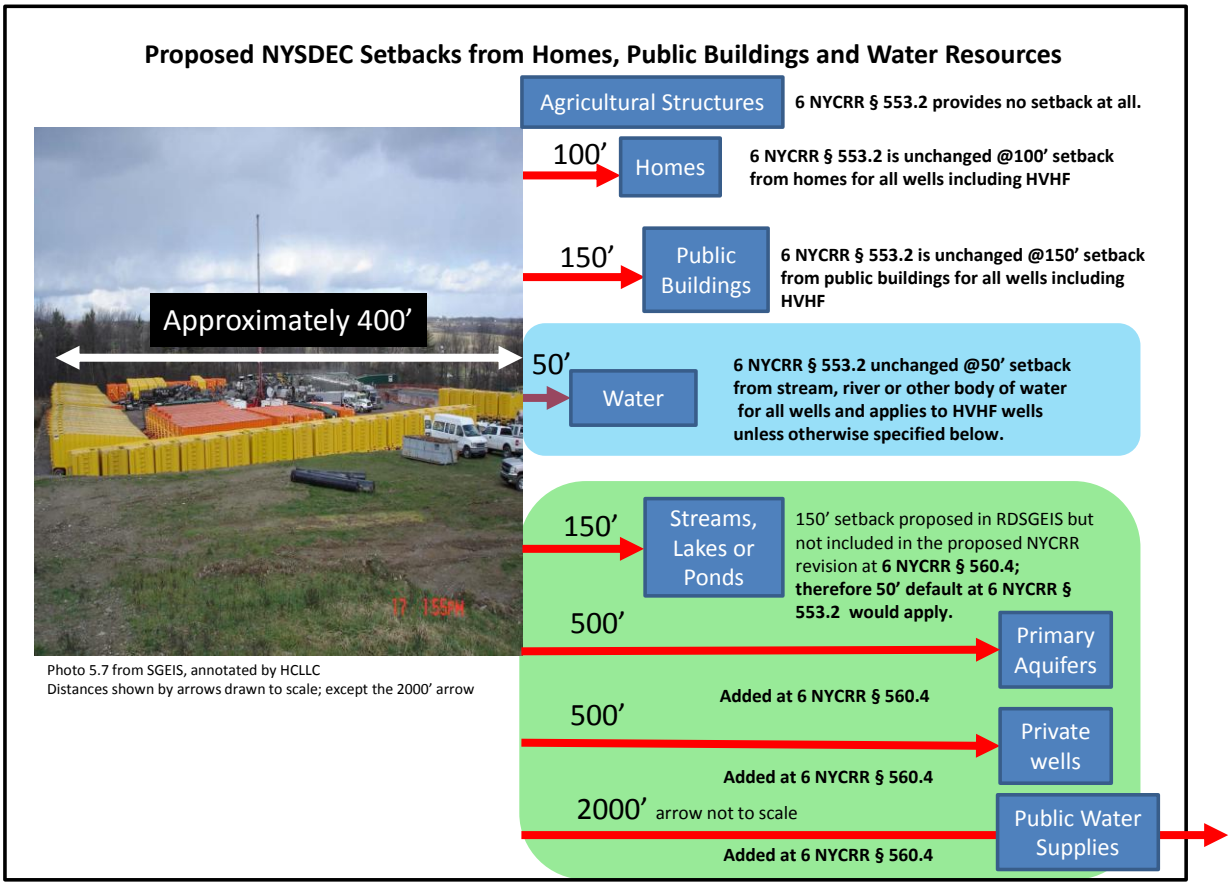
As shown in the figure below, the setbacks currently proposed in the RDSGEIS and in the NYCRR are inadequate. Shale drilling and HVHF operations within 100'-150' of homes and public buildings pose a direct safety risk, not to mention the health and quality of life impacts presented. NYSDEC is proposing

[294] 2011 NYSDEC, RDSGEIS, Page 3-10.

[295] Well step-out distance that can be achieved will depend on well depth.

[296] BP, Extended-Reach Drilling: Breaking the 10-km Barrier, 1997.

to allow shale drilling and HVHF operations to run 24 hours a day, 7 days a week, which will result in significant impacts to human health and quality of life—disrupting sleep, work, schooling, and recreational patterns for nearby residents.



By comparison, the local zoning setback requirements for Barnett Shale development implemented in the urban area of Fort Worth, Texas are substantially larger than those proposed for NYS.[297] As shown in the figure below, the required setback from a home is six times larger at 600', as compared to NYS' 100' setback. Additionally, Fort Worth, Texas has implemented setbacks of at least 300' from public buildings and 600' from schools, which is more than double what is proposed by NYSDEC.[298]

At a state level, Wyoming requires a minimum setback of 350' from "water supplies, residences, schools, hospitals, and other structures where people are known to congregate."[299] The below photograph shows the proximity of homes to a well pad in Pennsylvania, where a 200' minimum setback from homes is required.[300]

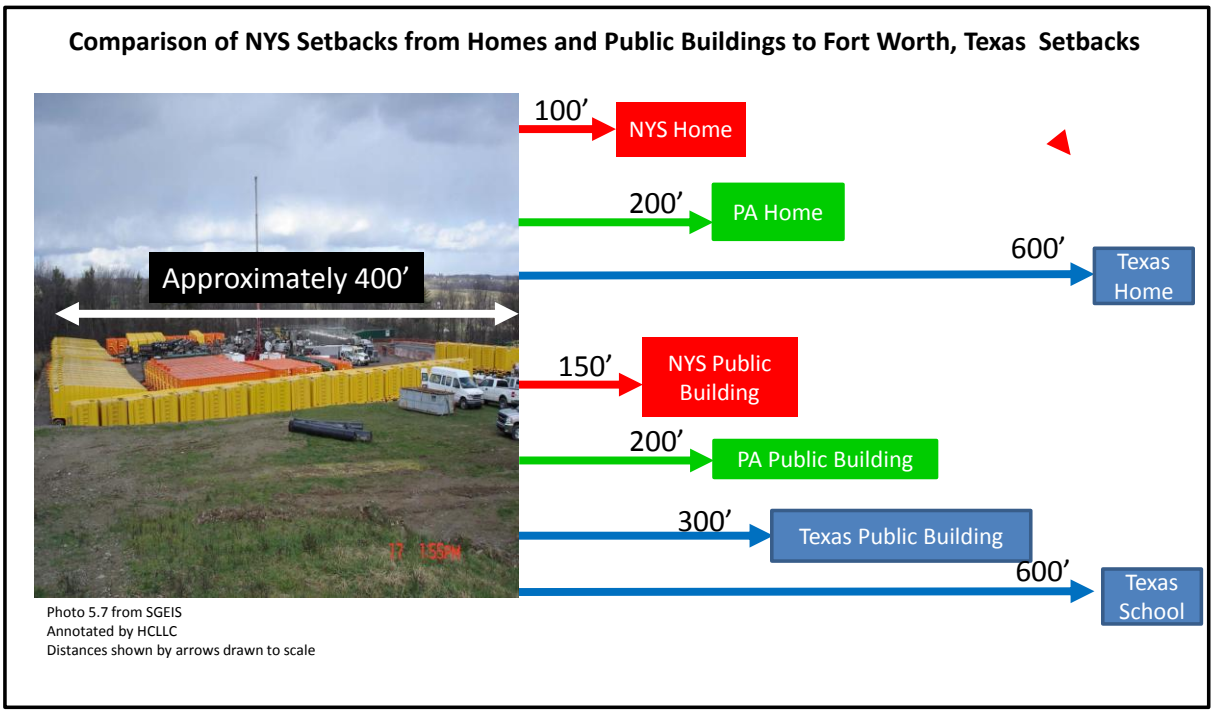
[297] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009; the Code of Ordinances of the City of Forth Worth § 15-36(A).

[298] The Code of Ordinances of the City of Forth Worth § 15-34(N)(7), § 15-36(A).

[299] Wyo. Admin. Code OIL GEN Ch. 3 § 22(b).

[300] Governor's Marcellus Shale Advisory Commission Report, Prepared for Governor Corbett of Pennsylvania, July 22, 2011.

The photo above shows homes within close proximity to shale drilling operations in Hopewell Township, Washington County, PA.



Recommendation No. 68: Improved setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Specifically, the SGEIS and NYCRR should be revised at 6 NYCRR § 553.2 to include the following minimum setbacks: homes, public buildings, and schools (1,320'; ¼ mile); private and public wells, primary aquifers, and other sensitive water resources (4,000'); and other water resources (660'; 1/8 mile). Additionally, NYSDEC should clarify the authority of local zoning authorities to establish minimum setbacks that are more protective than NYS' minimum standards in order for localities to address unique and site-specific local concerns and community characteristics.

In addition to the inadequate minimum setback requirements, the NYCRR allows an operator to move its surface location by 75' without obtaining a permit amendment. 6 NYCRR § 552.3(b). Absent NYSDEC and public review, a 75' adjustment is very significant, especially when setbacks as low as 50' to 150' are used. The regulations at 6 NYCRR § 552.3 explain that a 75' surface location adjustment is allowed, without any permit amendment process, to account for surface obstructions or topography. However, if an operator's due diligence and site planning during the original permit process include an examination of surface obstructions and topography, later adjustments should not be necessary.

Recommendation No. 69: The NYCRR should be revised at 6 NYCRR § 552.3 to allow the well location to be adjusted by 75' without a permit amendment only if all the statewide and local setback requirements are still preserved.

The proposed regulations that govern HVHF SPDES permits also suffer from inadequate minimum setback requirements. The revisions proposed to 6 NYCRR § 750-3.3 include: a 4,000' setback from an unfiltered water supply; a 500' setback from a primary aquifer; no operations within a 100-year floodplain; and a 2,000' setback from a public water supply, including wells, natural lakes, man-made impoundments, rivers and streams. However, neither the existing regulations nor the proposed revisions to 6 NYCRR § 750-3.3 include setbacks from streams, rivers, or other bodies of water that are not specifically designated as public water supplies. Thus, HVHF operations potentially could be as close as 50' to streams, rivers, or other bodies of water, based on 6 NYCRR § 553.2. Also, the proposed regulations do not require a minimum setback of HVHF operations from private wells.

Further inconsistency is introduced in the proposed revisions to 6 NYCRR § 750-3.21, which prohibit HVHF operations within 100' of a wetland. While this setback requirement is recognized in the RDSGEIS,[301] the proposed revisions to 6 NYCRR § 553.2 and 6 NYCRR § 560.4 do not include a parallel requirement. These sections of the regulations should be revised to include a wetland setback.

Recommendation No. 70: The NYCRR should be revised at 6 NYCRR § 553.2 to include a wetland setback of at least 100' as described in the RDSGEIS.

The proposed revisions to 6 NYCRR § 750-3.21(f)(3) do not authorize the issuance of a SPDES permit for HVHF operations within 150' of storm drains, lakes, ponds, and perennial or intermittent streams, which conflicts with the 50' setback established at 6 NYCRR § 553.2. There remains confusion about which setbacks would be applied to lakes, ponds, and perennial or intermittent streams and rivers.

Recommendation No. 71: The NYCRR should be revised at 6 NYCRR § 750-3.3, 6 NYCRR § 750-3.2, 6 NYCRR § 553.2, and 6 NYCRR § 560.4 to provide consistent setback requirements that are protective of water sources, including rivers, streams, lakes, and private water supplies.

NYCRR should be clear that the intent, as stated in the RDSGEIS, is to measure setbacks from the edge of the drillsite, and to attempt to center wells on the drillsite to maximize the distance from the well to the drillsite edge.

Recommendation No. 72: NYCRR and the SGEIS should clarify that setbacks are measured from the edge of the drillsite. Wells should be centered on the well pad and should be set back at least 100' from the pad edge, to maximize well setbacks from sensitive receptors.

[301] 2011 NYSDEC, RDSGEIS, Page 2-34.

19. Disposal of Drilling & Production Waste and Equipment Containing Naturally Occurring Radioactive Material (NORM)

Background: In 2009, HCLLC made recommendations to NYSDEC on best practices for disposal of drilling and production waste and equipment containing Naturally Occurring Radioactive Materials (NORM). NORM includes uranium, thorium, radium, and lead-210 and their decay products.[302] Additionally, radon, a component of natural gas, decays into radioactive polonium.

NORM can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

In January 2011, NYSDEC's consultant, Alpha Geoscience, agreed that the disposal of waste containing NORM is an important issue that should be addressed in the SGEIS. Alpha Geoscience's review of HCLLC's recommendations on NORM concluded that:

> *Harvey Consulting's recommendation to analyze practices for NORM testing, NORM treatment, and NORM disposal appears to be complete and well-researched. The review presents a concise analysis of practices involving the testing for and the treatment and disposal of NORM.*
>
> *Harvey Consulting's review of the dSGEIS's content regarding NORM is supported by a range of reliable sources. References include the EPA's website, USGS fact sheets, Texas Railroad Commission regulations, and a publication by Argonne National Laboratory.*[303]

Alpha Geoscience recommended that the SGEIS include a detailed analysis of NORM testing, treatment, transportation, and disposal methods:

> *Alpha suggests that **it may be useful to operators if the SGEIS includes NYSDEC's detailed analyses of NORM testing, treatment, transportation, and disposal**. This information may prove useful to the operator for developing handling and disposal plans [emphasis added].*[304]

[302] USEPA Oil and Gas Production Wastes, NORM, http://www.epa.gov/radiation/tenorm/oilandgas.html.

[303] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 9-11.

[304] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 12.

Yet, Alpha Geoscience recommended against adopting specific regulations to formalize NORM testing, treatment, transportation, and disposal requirements in NYS; instead, Alpha Geoscience recommended that NYSDEC "consider" having "temporary guidelines:"

> ***Alpha suggests that NYSDEC consider having temporary guidelines regarding NORM*** *in place, to clarify expectations and requirements for operators prior to the commencement of operations. This also would be helpful to operators for the design of handling and disposal plans [emphasis added].*[305]

HCLLC disagrees with Alpha Geoscience's recommendation for temporary NORM disposal guidelines. The requirements for testing, treatment, transportation, and disposal of NORM should be formalized in NYCRR. The rules should be clear to industry and the public, and enforceable by NYSDEC.

The 2009 DSGEIS acknowledged that drilling and production waste and equipment may contain NORM. NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and this NORM may be present in drill cuttings, produced water, and stimulation treatment waste.[306] 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.[307] Radiation pathways can include external gamma radiation, ingestion, inhalation of particulates, and radon gas.[308]

In 2009, HCLLC recommended that the SGEIS address the potential for equipment scale and sludge to contain high concentrations of NORM. HCLLC explained that equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[309] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[310] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[311] The most common form of scale is barium sulfate, which readily incorporates radium in its structure. HCLLC noted that, because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[312] it is critical that states establish clear best practice requirements for handling E&P waste, especially for NORM found in equipment scale and sludge. HCLLC pointed out that other oil and gas states, such as Texas and Louisiana, have adopted stringent NORM regulations, including: occupational dose control, surveys; testing and monitoring; record keeping; signs and labeling; and treatment and disposal methods.[313]

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[305] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 11.

[306] 2009 NYSDEC, DSGEIS, Page 4-36.

[307] 2009 NYSDEC, DSGEIS, Page 6-129.

[308] 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.

[309] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[310] 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.

[311] 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.

[312] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.

[313] 2009 NYSDEC, DSGEIS, Page 7-101.

The 2011 RDSGEIS: The 2011 RDSGEIS provided some improved data and acknowledged the risk of significant impacts from improperly disposed waste containing NORM. The RDSGEIS concluded that the NORM dataset is limited and there can be significant variability in NORM content. The 2011 RDSGEIS based its conclusions on data collected in other states; this data examined Marcellus Shale cuttings, produced water, and HVHF flowback.

However, the 2011 RDSGEIS still does not establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g. for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Recommendation No. 73: Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

Equipment Containing NORM: The 2011 RDSGEIS contains substantially improved requirements for equipment containing NORM, including a new radiation testing requirement and a treatment and disposal threshold limit. The RDSGEIS concludes that pipe scale and sludge (NORM buildup in equipment) can result in NORM concentrations that may have a significant adverse impact.

The 2011 RDSGEIS clarifies that NYSDOH will require the well operator to obtain a radioactive materials license for its facility when exposure rate measurements associated with scale accumulation in or on piping, drilling, and brine storage equipment exceeds 50 microR/hr[314] (μR/hr).[315] The RDSGEIS does not explain the origin of the 50 μR/hr limit; however, this limit has been used by a number of oil and gas producing states, including Texas[316] and Louisiana.[317]

[314] Microroentgens per hour (μR/hr) is a measurement of exposure from x-ray and gamma ray radiation in air.

[315] 2011 NYSDEC, RDSGEIS, Page 5-142.

[316] Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, Economic Regulation, Railroad Commission of Texas, Environmental Protection, Oil and Gas NORM.

[317] Louisiana Administrative Code, Title 33 LAC Part XV, Radiation Protection.

Presumably, equipment containing a radioactive concentration of less than 50 µR/hr would be disposed of in a NYS landfill; however, it is unclear if NYS' landfills are designed to accommodate waste containing radioactivity of up to 50 µR/hr.

Recommendation No. 74: NYSDEC should explain the origin of the 50 µR/hr limit, and explain how NYS determined that this threshold is sufficiently protective for NYS. The SGEIS should explain where equipment containing a radioactive concentration of less than 50 µR/hr would be disposed (e.g. a NYS landfill), and whether this waste disposal method was designed for this waste handling purpose.

The RDSGEIS Chapter 7 (Section 7.7.2) proposes NORM testing (radiation survey) requirements:

> ***The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup.*** *The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27. The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would fully mitigate any potential significant impacts from NORM [emphasis added].*[318]

NYSDEC's proposal to require NORM testing (radiation surveys) for HVHF wells and equipment is an important improvement. This proposed mitigation measure is effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 65, requires:

> *65) Periodic* ***radiation surveys must be conducted at specified time intervals*** *during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed, radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols [emphasis added].*[319]

However, this permit condition is only applied to HVHF wells and equipment. NORM can accumulate in all oil and gas equipment; therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the radiation testing frequency and method be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[320] Furthermore, Dr. Glenn Miller and Dr.

[318] 2011 NYSDEC, RDSGEIS, Page 7-119.

[319] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[320] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

Ralph Seiler recommended that radiation testing not be limited to radium. For example, Dr. Ralph Seiler points out in his comments that while NYSDEC has identified Radium (Ra) as a contaminant of concern, NYSDEC has overlooked the potential significant unmitigated impact of Polonium 210 (^{210}Po) accumulating in pipe scale as a byproduct of radon decay (natural gas contains radon).[321]

Recommendation No. 75: The requirement for radiation surveys should be codified in the NYCRR and applied to all oil and gas operations, not just HVHF operations. Radiation testing frequency and method should be specified to ensure that all potential radiation impacts are assessed and quantified. The proposed HVHF Permit Condition No. 65 could serve as a starting point for the NYCRR revisions.

Produced Water and Flowback Wastewater NORM: In 2009, HCLLC pointed out that water produced from wells can be rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[322] HCLLC also noted that flowback wastewater can contain NORM.

In 2009, NYSDEC reported that it had insufficient data on NORM in produced water and flowback wastewater, but acknowledged that NORM is present and is known to be found in elevated levels in produced water.

The Department of Energy (DOE) explains the presence of NORM in produced water:

> ***Because the water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself.*** *It may include water from the reservoir, water injected into the formation, and any chemicals added during the production and treatment processes. Produced water is also called "brine" and "formation water."* ***The major constituents of concern in produced water are****:*
>
> - *Salt content (salinity, total dissolved solids, electrical conductivity)*
> - *Oil and grease (this is a measure of the organic chemical compounds*[323]
> - *Various natural inorganic and organic compounds or chemical additives used in drilling and operating the well*
> - ***Naturally occurring radioactive material (NORM).***
>
> *The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological host formation, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir [emphasis added].*[324]

[321] Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[322] 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.

[323] In addition to the major constituents of concern listed by DOE for produced water, Dr. Glenn Miller notes that both the gasoline and diesel range hydrocarbon fractions should be monitored, since they are more soluble than heavy hydrocarbons.

[324] United States Department of Energy, Produced Water Management Information System, http://www.netl.doe.gov/technologies/pwmis/intropw/index.html.

Since 2009, NYSDEC gathered additional information and improved the 2011 RDSGEIS to acknowledge and quantify the potential adverse impact of produced water radioactivity. Although NYSDEC's research shows that flowback waste may not contain significant concentrations of radioactive material, NYSDEC acknowledges it has a limited dataset, and proposes radiation surveys for both types of wastewater (flowback and produced water).

NYSDEC's proposal to require NORM testing (radiation surveys) for flowback and production brine is a significant improvement to the 2011 RDSGEIS, and this proposed mitigation measure was effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 64, requires:

> *64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.*[325]

However, this permit condition is only applied to HVHF wells and equipment. NORM can be present in all flowback wastewater, including hydraulic fracture treatments less than 300,000 gallons, and produced water from wells that are not subject to HVHF treatments. Therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the NORM testing method and frequency be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[326]

Recommendation No. 76: The requirement to test produced water (production brine) and flowback wastewater (waste from hydraulic fracturing operations) should by codified in the NYCRR and applied to all oil and gas operations. NORM testing frequency and method should be specified. Proposed HVHF Permit Condition No. 64 could serve as a starting point for NYCRR revisions.

The RDSGEIS proposes to allow flowback wastewater and produced water to be disposed of at a Publically Owned Treatment Works (POTW), as long at the influent concentration of radium-226 (as measured prior to admixture with POTW influent) is limited to 15 pCi/L,[327] or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.

> *The Department proposes to require, as a permit condition, that the permittee demonstrate that it has a source to treat or otherwise legally dispose of wastewater associated with flowback and production water prior to the issuance of the drilling permit.* ***Disposal and treatment options include publicly owned treatment works, privately owned high volume hydraulic fracturing wastewater treatment and/or reuse facilities, deep-well injection, and out of state disposal.***

[325] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[326] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[327] Picocuries per gram (pCi/g) is a measure of the radioactivity in one gram of a material. One picocurie is that quantity of radionuclide(s) that decays at the rate of 3.7 x 10-2 disintegrations per second.

> ***Flowback water and production water must be fully characterized prior to acceptance by a POTW for treatment****. Note in particular Appendix C. IV of TOGS 1.3.8, Maximum Allowable Headworks Loading. The POTW must perform a MAHW analysis to assure that the flowback water and production water will not cause a violation of the POTW's effluent limits or sludge disposal criteria, allow pass through of unpermitted substances or inhibit the POTW's treatment processes. As a result, the SPDES permits for POTWs that accept this source of wastewater will be modified to include influent and effluent limits for Radium and TDS, if not already included in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge.* ***In the case of NORM, anyone proposing to discharge flowback or production water to a POTW must first determine the concentration of NORM present in those waste streams to determine appropriate treatment and disposal options. POTW operators who accept these waste streams are advised to limit the***
>
> ***concentrations of NORM in the influent to their systems to prevent its inadvertent concentration in their sludge.*** *For example,* ***due to the potentially large volumes of these waste waters that could be processed through any given POTW, as well as the current lack of data on the level of NORM concentration that may take place, it will be proposed that POTW influent concentrations of radium-226 (as measured prior to admixture with POTW influent) be limited to 15 pCi/L, or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.*** *As more data become available on concentrations in influent vs. sludge it is possible that this concentration limit may be revisited [emphasis added].*[328]

EPA data shows that produced water can contain 0.1 to 9,000 pCi/L of radium-226.[329] Therefore, it is reasonably foreseeable that there will be substantial volumes of wastewater that will exceed the 15 pCi/L POTW influent limit. NYSDEC has not proposed a waste treatment or disposal solution for wastewater that exceeds the 15 pCi/L POTW influent limit.

Recommendation No. 77: The SGEIS should examine treatment and disposal options, and capacity within NYS, for wastewater exceeding 15 pCi/L radiation.

Additionally, it is unclear if NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation. The Federal Safe Drinking Water standard is 5 pCi/L[330] (radium-226 and radium -228 combined).[331] The 5 pCi/L threshold was set because of the increased risk of cancer above this level. Because the RDSGEIS does not examine NYS' POTW's ability to treat incoming wastewater with 15 pCi/L radiation, it does not provide an estimate of the expected radiation level at the POTW effluent. Therefore, it is not clear whether POTW effluent discharge at a level greater than 5 pCi/L could end up in a drinking water supply, or how NYSDEC plans to monitor and ensure that this does not happen.

[328] 2011 NYSDEC, RDSGEIS, Page 6-58 and 6-59.

[329] USEPA Oil and Gas Production Wastes, Summary Table of Reported Concentrations of Radiation in TENORM, http://www.epa.gov/radiation/tenorm/sources.html#summary-table

[330] Measured as Radium 226 and Radium 228 combined.

[331] USEPA Federal Safe Water Drinking Water Standards for Radionuclides at http://water.epa.gov/drink/contaminants/index.cfm#List.

Recommendation No. 78: The SGEIS should examine whether NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation, and should predict the maximum effluent radiation level. The SGEIS should explain how NYSDEC will ensure that drinking water sources will not exceed 5 pCi/L radiation.

The 2011 RDSGEIS does not prohibit road spreading of waste; it deferred this decision to a yet-to-be determined future process outside the SGEIS review. Yet, other oil and gas producing states, such as Texas, specifically prohibit road spreading of waste containing NORM.[332] 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.[333]

Most states dispose of wastewater using deep well injection or use it to enhance hydrocarbon recovery operations. Land disposal is not common for onshore operations. The Department of Energy reports that more than 98% of oil and gas wastewater from onshore operations is injected into underground disposal wells, which are regulated by EPA, or used for enhanced hydrocarbon recovery.[334] The 2009 DSGEIS explored produced water treatment and disposal options (e.g. injection wells, treatment plants, and road spreading),[335] but did not land on a best practice.

The 2011 RDSGEIS concludes there is not enough information available to allow for road spreading under a Beneficial Use Determination (BUD).[336] However, the RDSGEIS does not explicitly state that road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

Since the current BUD does not require an operator to test for NORM,[337] it is unclear how NORM testing at the well site will be integrated into the BUD process. The level of NORM, if any, that will be allowed in fluids used for road spreading is also unclear. The 2011 RDSGEIS does not examine the cumulative impact of spreading small amounts of NORM repeatedly over the same area. It is recommended that land and road spreading of produced water and other waste containing NORM be **prohibited**. 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.

Recommendation No. 79: The SGEIS should explicitly state that land and road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

[332] 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.

[333] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[334] Argonne National Laboratory, Produced Water Volumes and Management Practices in the United States, Report Prepared for United States Department of Energy, Report No. ANL/EVS/R-09/1, 2009.

[335] 2009 NYSDEC, DSGEIS, Page 5-131.

[336] 2011 NYSDEC, RDSGEIS, Page 7-60.

[337] 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.

The Environmental Protection Agency (EPA) identifies produced water pits (brine pits) as an outdated practice in cases where produced water contains NORM. If wastewater pond sediments pose a potential radiological health risk, tank sediments from wastewater stored in tanks also would pose a radiological health risk. 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*[338] *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 [emphasis added].*[339]

Recommendation No. 80: The SGEIS should address testing of wastewater sediments, and explain the collection, transportation, treatment, and disposal methods for this potential radiological health risk.

Drill Cutting NORM: The 2011 RDSGEIS acknowledges the fact that drill cuttings can contain NORM, but makes a blanket assumption that the level of radiation from cuttings will be low. The RDSGEIS does not require site-specific testing to verify this assumption, nor does it preclude cuttings disposal in existing solid waste landfills. Instead, the RDSGEIS only recommends that the well operator consult with the landfill operator prior to drill cuttings disposal.

> *In New York State the* ***NORM in cuttings is not precluded by regulation from disposal in a solid waste landfill****,* ***though well operators should consult with the operators*** *of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility [emphasis added].*[340]

The 2011 RDSGEIS is unclear about the environmental and human health protections that would be achieved via the landfill consultation process. Appendix 10, Proposed EAF Addendum Requirements for HVHF, requires the operator to specify where it plans to dispose of cuttings, and requires evidence that the cuttings will go to a Part 360 solid waste landfill. However, the RDSGEIS does not provide scientific or engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM.

NYSDEC acknowledges significant uncertainty about the NORM content of drill cuttings in Chapter 7, and raises questions as to whether there are sufficient data to fully assess NORM impacts at this time. The 2011 RDSGEIS states:

> ***Existing data from drilling in the Marcellus Formation*** *in other States, and from within New York for wells that were not hydraulically fractured,* ***shows significant variability in NORM content.*** *This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability.*

[338] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

[339] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

[340] 2011 NYSDEC, RDSGEIS, Page 5-129 and 5-130.

> ***<u>During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability</u>****. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York [emphasis added].*[341]

Yet, the 2011 RDSGEIS does not propose NORM mitigation measures. It does not require drill cuttings testing prior to disposal in the landfill, nor does it establish a maximum allowed NORM disposal threshold for safe long-term cuttings disposal in a landfill.

Recommendation No. 81: Drill cuttings should be tested for NORM prior to disposal in a landfill. A maximum allowed NORM threshold for drill cuttings disposal in the landfill should be clearly established and scientifically justified. Testing and threshold requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Waste exceeding the established NORM threshold should be handled under NYS' radioactive waste handling rules.

Chapter 5.2.4.2 of the 2011 RDSGEIS concludes that NORM content in drill cuttings is equivalent to background levels of radiation occurring naturally in the atmosphere. This conclusion is based on Geiger counter and gamma ray spectroscopy sampling methods.

Yet, Dr. Glenn Miller points out in his comments on the 2011 RDSGEIS[342] that gamma ray spectroscopy is insufficient to assess all radioactive constituents (e.g. polonium is radioactive and only a weak gamma ray emitter), and gamma ray measurements do not provide insight into the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate NORM when disposed. Dr. Miller concludes that NYS likely has underestimated the amount of NORM in drill cuttings, and recommends NYS require additional testing methods to verify total radiation levels and better understand the potential for drill cuttings to later oxidize, leach, and concentrate NORM when disposed. Additional work is needed to verify whether the disposal of drill cuttings containing NORM in existing NYS landfills is a best practice.

Recommendation No. 82: The SGEIS should provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, including lower concentrations of NORM that could cumulatively have a significant impact when stored in large volumes over long periods of time. The SGEIS should examine the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate radioactive materials within the landfill. If NYSDEC cannot provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, it should identify alternative collection, transportation, treatment, and disposal requirements.

NYCRR Proposed Revisions: Proposed Permit Condition No. 53 requires waste fluids be handled in accordance with 6 NYCRR § 554.1(c)(1); yet, this regulation does not specify the best practice for handling hydraulic fracturing fluid and other drilling and completion wastes. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for the applicant to submit a waste management plan. In 2009, HCLLC recommended revisions to this regulation; yet, none are proposed. The existing regulation states:

> *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* ***<u>sufficient quantities</u>*** *to be deleterious to the surrounding environment, the operator*

[341] 2011 NYSDEC, RDSGEIS, Page 7-119.

[342] Miller, G., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

> *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" are ambiguous, providing operators and regulators large latitude in how they interpret the regulation. Regulations should specify technically and scientifically based thresholds and management practices.

Under 6 NYCRR § 554.1(c)(1), the waste disposal method is selected by the applicant, with no instruction on how to determine the best waste management practice. While recycling and the reuse of fracturing fluid are discussed in the RDSGEIS, there is no requirement in the proposed permit conditions to use this best practice. Furthermore, NYSDEC does not explain how it will oversee the recycling and reuse processes.

Recommendation No. 83: Revisions are needed to 6 NYCRR § 554.1(c)(1) to require a more robust waste management planning and oversight process, including detailed instructions on collection, testing, transportation, treatment, and disposal of waste.

20. Hydrogen Sulfide

Background: In 2009, HCLLC recommended that the NYCRR require operators to follow American Petroleum Institute Recommended Practice 49 (API RP 49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide, and API RP 55 for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, to protect employees and the public.

The 2011 RDSGEIS: The 2011 RDSGEIS reports that Marcellus Shale operations in Pennsylvania have not produced substantial amounts of H_2S.[343] However, this conclusion is based on limited information from wells drilled only in Pennsylvania. These data do not confirm that H_2S will not be present initially or over time in NYS wells.

H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause serious health symptoms at elevated concentrations, and can be deadly at the higher concentrations found in some oil and gas wells.

The Occupational Safety and Health Administration (OSHA) recommends close monitoring of H_2S for human health and explosion mitigation:

> *Hydrogen Sulfide or sour gas (H2S) is a flammable, colorless gas that is toxic at extremely low concentrations. It is heavier than air, and may accumulate in low-lying areas. It smells like "rotten eggs" at low concentrations and causes you to quickly lose your sense of smell. Many areas where the gas is found have been identified, but pockets of the gas can occur anywhere.*
>
> *Iron sulfide is a byproduct of many production operations and may spontaneously combust with air.*
>
> *Flaring operations associated with H_2S production will generate Sulfur Dioxide (S02), another toxic gas.*
>
> *Active monitoring for hydrogen sulfide gas and good planning and training programs for workers are the best ways to prevent injury and death.*[344]

The American Conference of Governmental Industrial Hygienists recommends a Threshold Limit Value of 10ppm and a short-term exposure (STEL) limit of 15 ppm, averaged over 15 minutes, for the action level indicating the need for respiratory protection.[345] While workers may be afforded respiratory protection, nearby members of the public do not have routine access to respiratory protection and monitoring systems. Routine, standardized testing should also be in place to ensure public health and safety.

A 300 ppm concentration of H_2S is considered by the American Conference of Governmental Industrial Hygienists as Immediately Dangerous to Life and Health.

[343] 2011 NYSDEC, RDSGEIS, Page 5-138.

[344] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h2s_monitoring.html.

[345] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html.

> *In low concentrations, H_2S sometimes can be detectable by its characteristic odor; however, the smell cannot be relied upon to forewarn of dangerous concentrations (greater than 100ppm) of the gas because it rapidly paralyzes the sense of smell due to paralysis of the olfactory nerve. A longer exposure to the lower concentrations has a similar desensitizing effect on the sense of smell.*
>
> *It should be well understood that the sense of smell will be rendered ineffective by hydrogen sulfide, which can result in an individual failing to recognize the presence of dangerously high concentrations. Exposure to hydrogen sulfide causes death by poisoning the respiratory system at the cellular level.* [346]

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public.

While H_2S may not be initially present at a drillsite, the operator must remain vigilant in monitoring for H_2S over time, because sulfate reducing bacteria and other forms of acid producing bacteria can generate H_2S in the reservoir, such that H_2S concentrations elevate over time. Increasing levels of H_2S is a common problem in waterflooding operations in oil and gas fields. Biocides are typically used to mitigate bacteria growth; however, sometimes biocides are not successful.

Biocide use and close monitoring of H_2S early in field development is an important mitigation measure, because once elevated H_2S is present it is difficult to control. Industry anticipates H_2S will be a future concern in operations requiring large volumes of water for HVHF treatments, especially where treatment fluid is recycled, as planned in NYS. A 2010 Apache Corporation paper summarizes the problem:

> ***One of the most severe threats in recycling waters for fracs is the control of bacteria (Tischler, 2009), including sulfate reducing bacteria (SRBs) and other forms such as acid producing bacteria (APB), iron fixing bacteria and slime formers. SRBs have created souring of some conventional reservoirs from injection of waters, both produced and semi-fresh, which have established a presence in the reservoirs and create H_2S gas and iron sulfide problems.*** *Local well fouling problems are common where SRBs are spiked into the formation from drilling or completion fluids. This type of H_2S occurrence may cause local corrosion…in shale, however, the effect of uncontrolled bacteria is a general unknown, given the extremely large volumes of surface water used for slick water fracturing. For this reason, recycling of the water may seed all waters with bacteria and/or concentrate the bacteria; thus bacterial control is a necessity [emphasis added].* [347]

Due to the potential close proximity of Marcellus Shale operations to the public, a robust initial monitoring program should be instituted to determine H_2S concentrations in Marcellus Shale gas throughout NYS. As described in American Petroleum Institute Recommended Practices 49 and 55, monitoring frequency can be adjusted over time as site-specific information is obtained. Initial sampling should be conducted at each drillsite, with at least monthly sampling thereafter.

[346] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html

[347] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010, Page 30.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing, Permit Condition No. 25 includes a requirement to conform with API RP 49; however, there is no requirement for operators to conform with API RP 55, which applies after the well is drilled, during production operations.

NYCRR Proposed Revisions: As a control measure, when H_2S is present, the proposed regulations at 6 NYCRR § 560.6(c)(28) require the venting of any gas containing H_2S through a flare stack to combust the dangerous vapors.

Recommendation No. 84: H_2S monitoring and reporting requirements should be included in the RDSGEIS as a mitigation measure and codified in the NYCRR. Operators should be required to follow H_2S detection and handling procedures to protect employees and the public. Initial H_2S testing should be conducted at each drillsite. Subsequent test frequency should be based on the results of initial testing. H_2S levels can increase over time as gas fields age and sour. H_2S requirements should be included in regulation for both drilling and production operations, and should not just be relegated to a drilling permit condition. Additionally, when H_2S is present, nearby neighbors, local authorities, and public facilities should be notified, and provided information on the safety and control measures that the operator will undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

21. Chemical & Waste Tank Secondary Containment

Background: In 2009, HCLLC recommended that NYCRR be revised to include secondary containment for chemicals stored on the well pad or, alternatively, require 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.[348] Shale gas drilling and HVHF operations include the use of many chemical tanks and waste handling tanks (e.g. flowback tanks) that warrant secondary containment.

2011 RDSGEIS: NYSDEC responded to public comments and made appropriate revisions to the 2011 RDSGEIS with its requirement for 110% secondary containment for all chemical and waste handling tanks. It also requires secondary containment for chemical and waste transport, mixing and pumping equipment. The 2011 RDSGEIS states:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[349]
>
> *Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.*[350]
>
> *Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.*[351]
>
> *Secondary containment for flowback tanks is required.*[352]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[353]
>
> *Location of additive containers and* ***transport, mixing and pumping equipment****…within secondary containment…[emphasis added]*[354]

[348] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.

[349] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[350] 2011 NYSDEC, RDSGEIS, Page 7-38.

[351] 2011 NYSDEC, RDSGEIS, Page 7-38.

[352] 2011 NYSDEC, RDSGEIS, Page 7-40.

[353] 2011 NYSDEC, RDSGEIS, Page 1-12.

[354] 2011 NYSDEC, RDSGEIS, Page 7-29.

Recommendation No. 85: Secondary containment requirements for well site chemicals should be applied as a best practice to all oil and gas development and codified in NYCRR, and should not be limited to shale gas and HVHF operations.

NYCRR Proposed Revisions: Proposed regulations codify the requirement for secondary containment for chemical and waste handling tanks, but do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment.

Recommendation No. 86: Consistent with the proposed RDSGEIS mitigation, 6 NYCRR § 750-3.11 and 6 NYCRR § 560.6 should be revised to require lined secondary containment for chemical and waste transport, mixing, and pumping equipment.

Proposed regulations at 6 NYCRR § 750-3.11 provide very specific instructions on how to construct adequate secondary containment, including the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. Regulations also state that the containment structures must have adequate freeboard, be protected from damage, and be able to contain at least 110% of the largest tank volume.

> ***750-3.11 Applications of standards, limitations and other requirements***
>
> *(e) The HVHF SWPPP must, at a minimum, include the HVHF SWPPP General Requirements listed in subparagraph (1) below, Structural Best Management Practices (BMPs), Non-structural BMPs, and Activity-Specific SWPPP Requirements.*
>
> *(v) Secondary Containment - To prevent the discharge of hazardous substances, the owner or operator shall provide, implement, and operate secondary containment measures.* ***Such secondary containment shall be: (a) designed and constructed in accordance with good engineering practices, (b) constructed, coated or lined with materials that are chemically compatible with the environment and the substances to be contained, (c) provide adequate freeboard, (d) protected from heavy vehicle or equipment traffic; and have a volume of at least 110 percent of the largest storage tank within the containment area*** *[emphasis added].*

In contrast, proposed regulations at 6 NYCRR § 560.6 offer substantially less instruction on how to construct adequate secondary containment. They do not mandate the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. They do not require the containment structure have adequate freeboard. Nor do they require that the containment be protected from damage.

> ***§560.6 Well Construction and Operation.***
>
> *(c) Drilling, Hydraulic Fracturing and Flowback.*
>
> *(26) Hydraulic fracturing operations must be conducted as follows:*
>
> *(i) secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required.* ***Secondary containment measures may include, as deemed appropriate by the department, one or a combination of the following: dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance****. Any such secondary containment must be sufficient to contain*

> *110 percent of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order [emphasis added].*

Recommendation No. 87: 6 NYCRR § 560.6 should be revised to include specific secondary containment construction standards that are consistent with 6 NYCRR § 750-3.11.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing: Permit conditions have been developed to require secondary containment. However, the permit conditions merely echo proposed regulations at 6 NYCRR § 560.6. They do not provide additional or supplemental requirements to the NYCRR.

Recommendation No. 88: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing contained in the RDSGEIS to remove requirements that are redundant with NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

22. Fuel Tank Containment

Background: In 2009, HCLLC recommended that the NYCRR be revised to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities, and that NYS' regulations be at least as stringent as federal EPA's Spill Prevention Control and Countermeasures (SPCC) Plan. HCLLC recommended that NYSDEC incorporate existing EPA oil spill prevention standards into the NYCRR. EPA standards require secondary containment if a facility stores 1,320 gallons of fuel or more (30 CFR § 112), including portable, temporary fuel tanks.

In 2009, NYSDEC proposed to exempt drilling rig and HVHF fuel tanks (even those as large as 10,000 gallons) from NYS' petroleum bulk storage regulations and tank registration requirements at 6 NYCRR §§ 612-614, citing the fact that the storage tanks are temporary (non-stationary) as the reason for the exemption. This problem persists in the 2011 RDSGEIS.

HCLCC questioned NYSDEC's rationale for exempting drilling rig and HVHF fuel tanks from NYS' spill prevention regulations, as all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5- and 10-year intervals.

HCLLC pointed out that a temporary fuel tank poses a greater environmental risk than a stationary fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit and the likelihood of tank appurtenance leakage.

Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks in NYS, particularly in situations where temporary fuel tanks are installed in one location for a significant period of time (e.g. a multi-well pad where drilling and completion operations could span several years). Alternatively, where secondary containment is not technically feasible, the use of double-walled or vaulted tanks should be considered for portable fuel tanks.

In January 2011, NYS' consultant, Alpha Geoscience, reviewed HCLLC's recommendation and provided NYSDEC with incorrect guidance on EPA's secondary containment requirements for onshore oil drilling workover and mobile equipment and other fuel storage.[355] Alpha Geoscience advised NYSDEC that EPA's SPCC regulations only addressed stationary fuel tanks greater than 1,320 gallons.

Alpha Geoscience's advice was incorrect because EPA's SPCC rules apply to facilities that have an aggregate fuel or hydrocarbon storage of 1,320 gallons or more at a facility, and secondary containment rules are not limited to stationary tanks.[356]

2011 RDSGEIS: NYSDEC's 2011 proposal for fuel tank secondary containment is confusing and inconsistent. The RDSGEIS both recommends and requires fuel tank secondary containment as a best practice, yet also exempts large fuel tanks used for drilling and HVHF operations.

For example, the 2011 RDSGEIS states that secondary containment will be required for fuel tanks and areas where fuel transfers occur:

[355] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 21.

[356] USEPA, SPCC Guidance for Regional Inspectors Version 1.0, November 28, 2005, Page 2-16.

> ***The Department proposes to require****, via permit condition and/or new regulation, that* ***operators provide secondary containment around all*** *additive staging areas and* ***fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans*** *[emphasis added].*[357]

NYSDEC supports its recommendation for fuel tank secondary containment by pointing out that its consultant has identified it as a best management practice:

> *In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York."* ***The best management practices referenced by Alpha include…Secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination*** *[emphasis added].*[358]

Yet, the 2011 RDSGEIS exempts large fuel tanks from secondary containment by designating drilling rig and HVHF fuel tanks as "temporary":

> *The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank.* ***Therefore, the tank is considered non-stationary and is exempt from the Department's petroleum bulk storage regulations and tank registration requirements*** *[emphasis added].*[359]

The 2011 RDSGEIS does not explain why a temporary fuel tank would pose less risk of a spill than a stationary fuel tank.

The 2011 RDSGEIS further confuses the issue by stating that all fuel tanks would be included in secondary containment:

> *The following measures are proposed to be required, via permit condition and/or regulation, to prevent and mitigate spills.* ***For all wells subject to the SGEIS****, supplementary permit conditions for high-volume hydraulic fracturing* ***would include the following requirements with respect to fueling tanks and refilling activities****:*
>
> > *a.* ***Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks****.*
> >
> > ***The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel****. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and*

[357] 2011 NYSDEC, RDSGEIS, Page 1-11.

[358] 2011 NYSDEC, RDSGEIS, Page 8-5.

[359] 2011 NYSDEC, RDSGEIS, Page 7-343.

infiltration. Draft Department Program Policy DER-1730 may be consulted for permeability criteria for dikes and dike construction standards, including capacity of at least 110% of the tank's volume [emphasis added]. [360]

Ultimately, the 2011 RDSGEIS, includes secondary containment requirements for all fuel tanks, in Appendix 10, Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing.

13) ***Secondary containment*** *consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks,(SPOTS 10)* ***is required for all fueling tanks*** *[emphasis added];*

14) *To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;*

15) *Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;*

16) *Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.* [361]

While, it is useful that the RDSGEIS finally lands on requiring secondary containment for fuel tanks, there remains a conflict in the text where NYSDEC has proposed to exempt temporary fuel tanks.

Recommendation No. 89: The SGEIS text should be revised to remove the temporary fuel tank exemption from secondary containment described on page 7-34.

Additionally, Appendix 10 permit conditions merely echo proposed regulations at 6 NYCRR § 560.6, and do not provide additional or supplemental requirements to the NYCRR. Therefore, if adopted into regulation, the permit conditions could be streamlined.

Recommendation No. 90: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing to remove requirements that are redundant with the proposed revisions to NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 codify the requirement for fuel tank secondary containment, and set no limit on the size or duration of fuel tank use. These proposed regulations are protective of the environment. The RDSGEIS should be revised to be consistent with the proposed regulations, avoiding future confusion about NYSDEC's intent.

§560.6 Well Construction and Operation.

(b) Site Maintenance.

(1) For any well:

[360] 2011 NYSDEC, RDSGEIS, Page 7-34.

[361] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 3.

*(i) **secondary containment is required for all fueling tanks** [emphasis added];*

(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 91: The SGEIS should be revised to be consistent with the proposed regulations, which require secondary containment for all fuel tanks (6 NYCRR § 560.6) used for shale gas drilling and HVHF operations.

While proposed regulations at 6 NYCRR § 560.6 are useful because they make it clear that secondary containment is required for all fuel tanks, the proposed regulations do not provide specific instruction on how to construct adequate containment.

Recommendation No. 92: 6 NYCRR § 560.6 should be revised to clearly state that all fuel tank secondary containment should be designed and constructed in accordance with good engineering practices, incremental to the minimum federal standards. Good engineering practices include: using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 require a 500' setback for fuel tanks from perennial or intermittent streams, storm drains, wetlands, lakes, and ponds, but only to the "extent practical" with no explanation of what that means in real terms, and under what conditions it would be acceptable to place a fuel tank closer. NYCRR does not include any setbacks from homes or public facilities.

§560.6 Well Construction and Operation.

(b) Site Maintenance.

(1) For any well:

(i) secondary containment is required for all fueling tanks;

*(ii) **to the extent practical**, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond[emphasis added];*

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 93: Proposed regulations at 6 NYCRR § 560.6 (b)(1)(ii) should be revised to delete the term "to the extent practical," and should include minimum setbacks for fuel tanks from homes and public buildings.

Additionally, the RDSGEIS is problematic because it still 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 secondary containment construction.

Recommendation No. 94: The SGEIS should not rely on a draft[362] 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 secondary containment construction. Instead, secondary containment requirements for fuel tanks should be codified in the NYCRR and written in a way that is clear, consistent, and enforceable.

The importance of secondary containment for fuel tanks extends beyond shale gas drilling and HVHF operations to all hydrocarbon drilling and HVHF operations.

Recommendation No. 95: Secondary containment requirements for fuel tanks should extend to all hydrocarbon drilling and HVHF operations in NYS. The requirements should not be limited to shale gas drilling and HVHF operations. Therefore, the recommendations made above should be captured in both 6 NYCRR § 560 and 6 NYCRR § 554.

The RDSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112, which apply to all fuel tanks, including drilling tanks, at 40 CFR § 112.7(c) and 40 CFR § 112.10(c). EPA's regulations, which were revised in 2002, require secondary containment for fuel tanks at facilities storing 1,320 gallons and more. 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." Under this determination, EPA requires periodic tank integrity testing, 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.

Recommendation No. 96: The SGEIS should cite federal standards (similar to how NYSDEC cited relevant USEPA standards for air quality) and notify the operator that the federal standards must be met. The SGEIS should also clearly explain what additional requirements will be imposed by NYS.

The RDSGEIS should also include: periodic fuel tank inspections to examine structural conditions and document corrosion or damage; the installation of high-liquid-level alarms that sound and display in an immediately recognizable manner; the installation of high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 97: In the NYCRR, NYSDEC should require tank inspections and tank alarm systems.

[362] If NYSDEC decides to refer to policy and guidance documents, those documents at a minimum should be final documents, and NYSDEC should state within those documents that the contents are enforceable.

NYSDEC does not address whether vaulted, double-walled, or self-diking tanks can be used as alternatives to constructing large temporary containment areas. Other oil and gas producing states allow the use of vaulted, self-diking, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate that 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 in places where secondary containment is proven to be infeasible.

Vaulted, self-diking, 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 the construction of vaulted, self-diking, 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 the higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self-diking, and double-walled portable tanks. The inspections should identify damage and 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).

As an oil spill prevention measure, portable tanks can be equipped with high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 98: NYSDEC should clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed, and codify in the NYCRR the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

23. Corrosion & Erosion Mitigation & Integrity Monitoring Programs

Background: In 2009, HCLLC recommended that NYSDEC require corrosion and erosion mitigation programs. More specifically HCLLC recommended that: equipment be designed to prevent corrosion and erosion; monitoring programs be put into place to identify corrosion and erosion over the well and equipment operating lifetime; and repair and replacement of damaged wells and equipment be completed.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves.

HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The 2011 RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require facilities be designed to resist corrosion (e.g. material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment.[363]

As explained in Chapter 20 of this report, the use of recycled HVHF fluid can result in the inoculation of sulfate reducing bacteria in the reservoir, and increased downhole equipment corrosion. And, while NYSDEC indicates that H_2S levels may be initially low in the Marcellus Shale, this may not be the case during the full life-cycle of the well. Nor does the RDSGEIS examine the H_2S of all other low permeability gas reservoirs to know what the H_2S might be for those formations.

Corroded well casings can provide a pathway for gas and well fluids to leak into protected aquifers. Therefore, it is important to install a robust casing system, and it's equally important to ensure that the casing system's integrity is maintained during the well's life.

Corrosion measured on production casing is an important piece of information, because corrosive fluids are known to also degrade the quality of the cement barrier. Corrosive fluids reduce the cement strength and make it more permeable, potentially providing a pathway for hydrocarbons to migrate from zones of higher pressure to lower pressure freshwater zones.

Additionally, the bond between the casing and cement can be compromised over the well's life, creating a "micro-annulus" (a space between the outer pipe wall and cement sheath) that allows vertical migration of hydrocarbons along the outside of the pipe wall. [364,365] Micro-annulus' can be formed during initial

[363] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

[364] See Ravi, K. (Halliburton), Bosma, M. (Shell) and Gastebled, O. (TNO Building and Construction Research), Safe and Economic Gas Wells through Cement Design for the Life of the Well, Society of Petroleum Engineering Paper No. 75700, 2002. Ravi et. al. concludes: "The extreme operating conditions that occur in gas-storage and gas-producing wells could cause the cement sheath to fail, resulting in fluid migration through the annulus…The sustained casing pressure observed on a number of wells after they have been put on production emphasizes the need to design a cement sheath that will maintain integrity during the life of the well…However, recent experience has shown that after well operations such as completing, pressure testing, injecting, stimulating and producing, the cement sheath could lose its ability to provide zonal isolation. This failure can create a path for formation fluids to enter the annulus, which pressurizes the well and renders the well unsafe to operate…Failure of the cement sheath is most often caused by pressure – or temperature-induced stresses inherent in well operations during the well's economic life."

cementing, or later in the well's life, due to: pipe wall thinning; cement deterioration; the shock of additional well workover activities (perforations, stimulation, drilling); pressure and temperature changes in the well; or by seismic vibrations.

In January 2011, NYS' consultant, Alpha Geoscience, recommended that NYSDEC ignore HCLLC's best practice recommendations for corrosion and erosion, citing Section 6.1.4.2 and 6.1.5.1 of the 2009 DSGEIS. In these sections, another NYS consultant (ICF) estimated the risk of groundwater contamination due to casing failure in a Class II injection well is 1 in 50 million wells.[366] Alpha Geoscience concludes that corrosion and erosion prevention, monitoring, and repair requirements are unnecessary in the NYCRR.

Neither Alpha Geoscience nor ICF provide technical justification for the use of a Class II injection well corrosion risk analysis as a surrogate for a gas well corrosion risk analysis. A Class II injection well risk profile is different than a gas well. Gas wells can continuously produce sources of corrosive gas (CO_2 and H_2S), water, and sediment, that can corrode and erode well casing and surface piping over time.

Neither Alpha Geoscience nor ICF examined:

- The full life cycle of a gas well, and the fact that there is substantial field evidence that well casings do corrode and erode over time;
- The fact that casing inspection logs, caliper logs, temperature surveys, and other wellbore diagnostics are commonly run to examine the well casing condition due to the known problem of gas well corrosion;
- Information on the amount of money spent annually on corrosion inhibitors, pipe coating, and other preventive measures to mitigate corrosion impacts;
- The fact that well service specialists routinely provide well casing patching, repair, and replacement services,[367] because gas well casing failure is a known problem; and,
- The fact that it is best practice to examine the condition of well casing over the well life to verify its integrity, especially before major well work (e.g. additional drilling, stimulation) is completed on an aging well.[368]

Additionally, Alpha Geoscience criticizes HCLLC for citing industry literature on corrosion best practices, stating that HCLLC's inclusion of this material shows industry bias. HCLLC disagrees with Alpha Geoscience's conclusion. Industry has developed most of the technology to address the problem; therefore, it is logical to cite industry literature on this point.

[365] See Stewart, R.B. and Schouten, F.C. (Shell), Gas Invasion and Migration in Cemented Annuli: Causes and Cures, Society of Petroleum Engineering Paper No. 14779, SPE Drilling Engineering, March 1988. Stewart and Schouten conclude: "*Gas migration resulting from casing contraction is a common field problem… Annular gas-migration problems can develop in an old well owing to changes in pressure or thermal conditions in the well.*"

[366] Alpha Geoscience, Review of the dSGEIS and Identification of Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 18.

[367] Storaune, A., Winters, W.J. (BP America Inc.), Versatile Expandables Technology for Casing Repair, Society of Petroleum Engineers, SPE Paper No. 92330-MS, SPE/IADC Drilling Conference, 23-25 February 2005, Amsterdam, Netherlands, 2005, p.1.

[368] Brondel, D., Edwards, R., Hayman, A., Hill, D., Shreekant, M., Semerad, T., Corrosion in the Oil Industry, Oilfield Review, April 1994, p. 9-10.

Experienced engineers know the importance of assessing and implementing programs to mitigate corrosion/erosion risk early in the field/well lifecycle. Corrosion of gas production equipment is a fundamental concern for the oil and gas industry that has been identified for decades.

> ***Failures of equipment handling or producing natural gas occur only in the absence of an adequate corrosion-control program. A successful program is shown to include (1) anticipation of corrosion in design factors of all equipment, (2) detection of corrosion within the system and measurement of its severity for future reference, (3) use of mitigation measures and (4) continual follow-up and adjustment of control techniques.*** *Design factors to be considered are tubing couplings, packers, tubing grade and size, and the number of tubing strings to be set.* ***Future corrosion problems and mitigation work should be recognized at the time the well completion is made so that the best possible design factors can be realized. Corrosion can be detected by gas analysis, water analysis, coupon exposures and caliper surveys. Quantitative data are needed to determine the severity of the problem and to design a suitable program of alleviation of the corrosion.*** *Use of inhibitors and plastic coatings are popular methods for mitigation of corrosion. Both methods have advantages and disadvantages that must be realized and evaluated. Control limits for a mitigation program should be established so that the operator can be certain that he is receiving the desired protection.* ***Gas gathering and process equipment also often suffer from corrosion….***
>
> *It is suggested that an adequate corrosion-control program must include efforts at various levels of company operations. All engineers and supervisors must participate actively in the corrosion-control effort.* ***As a property is being developed, corrosion control should be considered when the equipment to be used is being selected. When development is complete, the operating people must determine the seriousness of their corrosion problems. They must realize that the corrosion attack may change with changes in production characteristics and that absence of corrosion today does not guarantee absence of corrosion tomorrow. When corrosion is detected within an operation, mitigation is in order*** *[emphasis added].*[369]

Because of the known problem of casing corrosion, the National Association of Corrosion Engineers (NACE) developed Recommended Practice RP0186 to mitigate external casing corrosion; this standard applies to the design of cathodic protection for external surfaces of steel well casings, and would be used when soil/subsurface reservoir conditions present a corrosive environment warranting installation of cathodic protection system installation.[370]

NACE International writes:

> *Oil and gas wells represent a large capital investment.* ***It is imperative that corrosion of well casings be controlled to prevent loss of oil and gas, environmental damage, and personnel hazards, and in order to ensure economical depletion of oil and gas reserves necessary*** *[emphasis added].*[371]

[369] Fincher, D.R. (Tidewater Oil Co.), Corrosion in Gas Wells and Gas Gathering Systems, Journal of Petroleum Technology, Volume 13, Number 9, September 1961, Abstract.

[370] NACE International Standard RP0186-2001, Application of Cathodic Protection for External Surfaces of Steel Well Casings.

[371] NACE International, Application of Cathodic Protection for External Surfaces of Steel Well Casings, RP0186-2001, 2001, p.1.

Gas operators stress the importance of corrosion monitoring and control programs. For example, OMV Exploration and Production writes:

> ***Corrosion remains a key issue in petroleum production****. Its continued occurrence has consequences on the safety of people and environment and the integrity of facilities and affects the economy of the oil or gas field. Particularly the presence of severe environments containing corrosive components such as carbon dioxide and hydrogen sulphide poses serious problems.* ***A central element in the design of facilities and the corrosion control is therefore the proper choice of materials which are both economical and provide a satisfactory performance over the entire service life with respect to the given environment. Prior to the production phase reliable corrosion monitoring programmes have to be selected, established, and implemented, as necessary*** *[emphasis added].*[372]

The magnitude and complexity of a corrosion/erosion mitigation program will vary depending on site-specific conditions. The important step is to complete the initial evaluation, assess the site-specific circumstances, and develop an adequate corrosion/erosion mitigation plan. Some mitigation programs are started early, some are applied intermittently, and others are instituted later in the gas production process; in all cases, an engineering assessment prior to gas drilling and production must be completed to determine the optimal plan.

The corrosion engineering textbook, Corrosion Control in Oil and Gas Production, explains the importance of developing a site-specific plan:

> ***The many possible alternatives available today for corrosion management for gas and oil well environments, dictates the need for a thorough evaluation and development of long term plans to assure a safe, economical and effective program****. History has shown that both corrosion inhibition and corrosion resistant alloys (CRAs) have been used successfully in tough environments. The final decision on which method to use is often made on the basis of available capital versus long term operating costs [emphasis added].* [373]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantially improved well casing program, including a three-casing-string design. However, this casing is typically made of carbon steel, and must be protected from corrosion and erosion. Chromium steel and corrosion resistant alloys are commonly installed in corrosive environments; however, these metals are substantially more expensive and are not currently proposed for NYS.

Well casing, once installed and cemented into place, will remain in the well for its entire lifecycle, and is often abandoned in place.[374] Therefore, it is in the operator's best economic interest to ensure that its casing investment is protected from corrosion and erosion.

[372] Oberndorfer, M. (OMV Exploration and Production), Corrosion Control in the Oil and Gas Production-5 Successful Case Histories, CORROSION Conference 2007, March 11-15, 2007, Nashville Tennessee, NACE International, 2007, p.1.

[373] Treseder, R.S., Tuttle, R.N., Corrosion Control in Oil and Gas Production, Chapter 14, Corrosion of Steels in Gas Wells, 1998.

[374] In some circumstances corroded casing will be pulled from a well prior to abandonment, although this process can prove difficult, time consuming, and expensive for fully cemented casing strings.

It would be shortsighted for NYS to require a robust well casing program, and not build in a corrosion and erosion control program. Chemicals, metallurgy, monitoring, and repair techniques are available to the operator to manage corrosion and erosion downhole (in the well) and at its surface facilities (e.g. corrosion inhibitors, cathodic protection systems, coatings).

Tools that can be used to monitor well corrosion include caliper tools and casing inspection logs. A caliper tool is run down the inside of the well casing or tubing to measure the internal diameter and assess metal wall loss. Casing inspection logs use ultrasonic and magnetic-flux technology to estimate metal wall loss. Additionally, temperature surveys can be run to look for gas cooling anomalies in the well, which are an indication of casing holes. [375]

NYSDEC has proposed cement evaluation tools to be run when HVHF wells are initially drilled and completed, which is a best practice. Cement integrity should also be monitored periodically over the well's life if casing corrosion occurs. Casing corrosion is an indicator of potential cement deterioration, as explained above.

Without regulations, the decision to invest in corrosion/erosion mitigation and wellbore integrity monitoring is left to the operator. In some cases, operators postpone mitigation to improve early economics. Deferral strategies can produce unfavorable results in the long-term, but may be attractive to small operators that have limited funds, or to large operators that plan to reap the benefits of early production and sell assets soon thereafter. Operators may not implement, unless required, long-term monitoring when faced with declining production, lower profits and when operating cost cuts are sought.

Corrosion and erosion programs that are instituted early can prolong the life of equipment and well casings, and reduce environmental risk. Delayed attention to corrosion and erosion mitigation can result in increased safety, environmental, and human health risks.

Gas well corrosion and erosion can occur in many ways:

- Oxygen contaminated drilling fluids are injected downhole, and can corrode well casing and drilling equipment;
- Water produced along with gas can corrode well casing, tubing, and downhole equipment;
- Acid stimulation treatments, used alone or in conjunction with hydraulic fracturing, readily attack metal;
- Well casing and surface piping can be eroded by high gas production velocities, especially when laden with sediment, sands, or hydraulic fracturing proppants;
- Corrosive soils can cause external corrosion of carbon steel casing;
- Hydrogen sulfide and carbon dioxide, often present in gas production, can corrode carbon steel; and
- Higher wellbore temperatures, increased velocity, and increased salinity accelerate corrosion rates.

NYCRR Proposed Revisions: NYSDEC has not proposed any new requirements for corrosion or erosion mitigation for the Marcellus, Utica, or other low-permeability reservoirs. There are no requirements for corrosion or erosion mitigation or long-term well integrity monitoring in the existing NYCRR.

[375] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

Recommendation No. 99: Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be included in the SGEIS and codified in the NYCRR. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

24. Well Control & Emergency Response Capability

Background: In 2009, HCLLC recommended that NYSDEC require an operator to have an Emergency Response Plan (ERP) and a well blowout control plan. HCLLC recommended that operators be required to demonstrate that they have access to sufficient personnel and resources to respond to a fire, explosion, blowout, or other industrial accident. Best practices include: developing response and well control plans; verifying there are a sufficient number of trained and qualified personnel to carry out the plans; ensuring operators have access to the necessary response equipment; and testing (drills and exercises) the plan prior to drilling.

In 2009, HCLLC also recommended that NYSDEC examine the capacity of local emergency response teams. Oil and gas industry accidents often require highly specialized response capability and equipment. Operators should be required to supplement local emergency response resources to meet this need.

In January 2011, NYS' consultant, Alpha Geoscience, concluded that NYS well control and emergency response planning requirements are narrowly focused on the Bass Island Trend wells. Alpha Geoscience agreed with HCLLC that new regulations are needed for the formations proposed for development under this SGEIS.[376]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a new section (Section 7.13) on Emergency Response Plans, which is a substantial improvement. Section 7.13 states:

> *7.13 Emergency Response Plan*
>
> *There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities.* ***An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site.*** *The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets.* ***The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud.*** *The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department [emphasis added].*
>
> *The ERP, at a minimum, would also include the following elements:*
>
> - *Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;*
> - *Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;*
> - *Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional*

[376] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 42.

Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;

- *Identification and evaluation of potential release, fire and explosion hazards;*
- *Description of release, fire, and explosion prevention procedures and equipment;*
- *Implementation plans for shut down, containment and disposal;*
- *Site training, exercises, drills, and meeting logs; and*
- *Security measures, including signage, lighting, fencing and supervision.*[377]

Appendix 6, Proposed Environmental Assessment Form Addendum, requires an Emergency Response Plan be located at the rig, and that the plan be followed. [378]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 2, requires an ERP be provided 3 days prior to spud and available at the site. Condition No. 2 requires the ERP be developed in a manner consistent with the SGEIS, but it does not reference the Chapter 7.13 minimum requirements.

> *An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.* [379]

The addition of an Emergency Response requirement to the SGEIS is a substantial improvement. However, it is recommended that NYSDEC include a review, approval, and audit process to ensure that quality plans are developed. NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

As proposed by NYSDEC, the operator is required to submit an ERP three days prior to commencing drilling. This leaves no time for regulators to review and approve the ERP. NYSDEC proposes no process for determining the adequacy of the ERP. There is no assessment of personnel training and qualifications, equipment resources, or local emergency response services.

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems.

Larger, paid fire and emergency services departments, located near existing industrial developments, may have some industrial firefighting capability; however, the level of capability should be assessed by the operator and supplemented. If local emergency response services are relied upon in the ERP, operators should ensure emergency response personnel are trained, qualified, and equipped to respond to oil and gas industrial accidents. Small, local, volunteer fire and emergency services departments will typically not be equipped or qualified to meet this need.

[377] 2011 NYSDEC, RDSGEIS, Page 7-146.

[378] 2011 NYSDEC, RDSGEIS, Appendix 6, Page A6-7.

[379] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 1 of 17.

Recommendation No. 100: NYSDEC should identify an Emergency Response Plan (ERP) review, approval, and audit process to ensure that quality plans are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells.[380] This risk statistic is applicable to Marcellus and other low-permeability gas reservoir drilling that is still in the exploration and appraisal phase in NYS. Blowout rates are less frequent for production wells where more information is known about the reservoir, well control is optimized, and personnel are more experienced in site-specific conditions. For example, a review of production well blowouts in California estimated 1 blowout per 2,500 wells drilled. [381] California's data showed that: 25% of the blowouts affected more than 25 acres; the average blowout lasted 18 hours; and the maximum blowout length was 6 months.

Using the California statistic of 1 blowout per 2,500 production wells drilled (which is more conservative than the exploration well statistic of 7 blowouts per 1,000 exploration wells), and NYS' estimate of 1600 wells per year over 30 years, an incremental likelihood of 19 blowouts is estimated for NYS.[382] Because some of the early wells drilled will be exploration wells, the blowout frequency many be higher in the first few years of shale gas development in NYS and it is plausible that 40[383] or more well blowouts could occur during the next 30 years. Therefore, blowouts are a reasonably foreseeable significant impact, and mitigation is warranted.

Hydrocarbon reservoirs can contain large quantities of gas and formation water, which can be released into the surrounding environment during a well blowout, resulting in significant damage. For example, the Chesapeake Energy 2011 Marcellus well blowout in Bradford County, Pennsylvania spilled thousands of gallons of fracture treatment fluid over "containment walls, through fields, personal property and farms, even where cattle continue[d] to graze."[384]

Methods to control a gas well blowout can require significant water withdrawals – from 500,000 to 6,000,000 gallons per day. Well control experts may also use foam and dry chemicals to respond to a blowout. Controlling a well blowout can create large volumes of waste. Rig-deluge operations create large pools of water that can transport oil, chemicals, fuels, and other materials toward lower elevation drainage areas.

In addition to the Chesapeake Energy 2011 well blowout, another Pennsylvania Marcellus Shale blowout occurred in 2010.[385,386] Also, in 2010, there was a major industrial fire. The 2010 incidents prompted

[380] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[381] Jordan, P.D., and Benson, S. M., Well Blowout Rates in California Oil and Gas District 4- Update and Trends, Summary of Well Blowout Risks for California Oil and Gas District 4, 1991-2005, Table 1

[382] 19 blowouts= (1,600 wells drilled per year)(30 years)(1 blowout per 2500 wells drilled).

[383] 40 blowouts= 1,600 wells drilled per year)(2 years)(7 blowout per 1000 wells drilled)+(1,600 wells drilled per year)(28 years)(1 blowout per 2500 wells drilled).

[384] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[385] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

Pennsylvania to realize the need for its own emergency response services, with trained and qualified personnel and adequate equipment available 24 hours per day, 7 days per week. The news reported that it took "16 hours for out-of-state crews to address a June 3 blowout in Clearfield County and 11 hours to extinguish a July 23 fire in Allegheny County. In both cases, well operators had to wait for response crews to fly in from Texas."[387]

In 2010, CUDD Well Control located a new facility in Canton Township, Bradford County, Pennsylvania. Canton Township is located near the southern NYS border. It may be possible for NYS operators to contract with CUDD to provide emergency response services. However, a better alternative may be for NYS to collaborate with a well control specialist to provide more centrally located services dedicated to supporting NYS' proposed drilling activity.

The 2011 RDSGEIS requires operators to develop and implement a blowout preventer (BOP) testing program. However, the SGEIS does not unequivocally require a well control expert be on contract. It is recommended that NYSDEC require operators to have a contract in place for immediate response by a trained and qualified well control contractor. If a contract with a well control expert is not in place when a blowout occurs, contract negotiations can cause detrimental delays.

Well capping is a proven, effective, and rapid method to control a blowout. Well control contractors provide the expertise and equipment for this operation. However, in some limited cases, well capping is not effective, and a relief well may be required. Therefore, it is important for operators to also have prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement to provide emergency response assistance with a nearby operator.

Recommendation No. 101: NYSDEC should require a well blowout response plan (either included in the Emergency Response Plan or as a separate plan), a contract retainer with an emergency well control expert, and prearranged access to a relief well rig.

NYCRR Proposed Revisions: NYSDEC has proposed a new regulation at 6 NYCRR § 560.5 requiring an ERP for HVHF wells. This is a substantial improvement; however, this plan should be required for all wells in NYS, not just HVHF wells. Additionally, the NYCRR should more clearly specify the ERP content requirements and include the recommendations listed above.

Recommendation No. 102: The requirement for an Emergency Response Plan should be codified in the NYCRR. It should apply to all wells in NYS, not just HVHF wells. The NYCRR should specify ERP content requirements. These requirements should be consistent with NYSDEC's recommendations listed in Chapter 7.13 of the 2011 RDSGEIS.

[386] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[387] http://pagasdrilling.com/tag/cudd-well-control/

25. Financial Assurance Amount

Background: In December 15, 2008, scoping comments to NYSDEC, NRDC, and its co-signatories requested the DSGEIS examine whether NYSDEC requires a sufficient financial assurance amount (in the form of a bond or other financial instrument). In its comments on the 2009 DSGEIS, NRDC and its co-signatories, as well as HCLLC, noted that the DSGEIS did not provide an analysis of the current financial assurance requirements, and requested that work be done.

HCLLC recommended that the SGEIS examine financial assurance amounts to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to 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 are increased when high-volume fracture stimulation treatments are employed and multiple wells are drilled from a single well pad. Both of these operations require additional gas treatment and transportation facilities.

In January 2011, NYS' consultant, Alpha Geoscience, advised NYSDEC to ignore financial assurance recommendations, declaring it "out of scope" of the SGEIS, because legislative action would be required at ECL 23-0305(8)(k).[388] HCLCC disagrees. Regardless of whether a legislative change is required, financial assurance improvements for Marcellus Shale gas well drilling should not be disregarded in the RDSGEIS; instead, the SGEIS should recommend to NYS' Legislature the need for legislative action as a mitigating measure.

The 2011 RDSGEIS: The 2011 RDSGEIS still does not include recommendations for increasing the financial assurance amounts for HVHF shale gas operations.

NYCRR Proposed Revisions: There is no proposed revision to the amount of financial security for wells up to 6,000' deep. 6 NYCRR § 551.5. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000.

For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6).

In 2003, ICF completed a report for the New York State Energy Research and Development Authority (NYSERDA) on NYS oil and gas wells.[389] ICF's report advised NYS that well plugging and abandonment can range from $5,000 per well to more than $50,000 per well depending on the well depth, well condition, site access, and site condition.[390] ICF's 2003 report recommended that NYS consider increased financial security requirements. NYSDEC's current requirement of only $5,000 financial

[388] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 46.

[389] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003. This report is found at http://esogis.nysm.nysed.gov/esogisdata/downloads/NYSERDA/7012.pdf. The report is listed as a draft, and a final could not be located on the world-wide web.

[390] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page. ES-1.

security per well is clearly insufficient, if ICF determined in 2003 that the cost could be as much as $50,000 per well. Today's cost would likely be higher, almost a decade later.

In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas. The Ohio Code at Title 15, Chapter 1509 requires:

> ***1509.07 Liability insurance coverage.*** ***An owner of any well****, except an exempt Mississippian well or an exempt domestic well,* ***shall obtain liability insurance coverage*** *from a company authorized to do business in this state* ***in an amount of not less than one million dollars bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or plugging of all the owner's wells in this state.*** *However,* ***if any well is located within an urbanized area, the owner shall obtain liability insurance coverage in an amount of not less than three million dollars for bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or plugging of all of the owner's wells in this state****. The owner shall maintain the coverage until all the owner's wells are plugged and abandoned or are transferred to an owner who has obtained insurance as required under this section and who is not under a notice of material and substantial violation or under a suspension order. The owner shall provide proof of liability insurance coverage to the chief of the division of oil and gas resources management upon request. Upon failure of the owner to provide that proof when requested, the chief may order the suspension of any outstanding permits and operations of the owner until the owner provides proof of the required insurance coverage.[emphasis added]*
>
> *Except as otherwise provided in this section, an owner of any well, before being issued a permit under section 1509.06 of the Revised Code or before operating or producing from a well, shall execute and file with the division of oil and gas resources management a surety bond conditioned on compliance with the restoration requirements of section 1509.072, the plugging requirements of section 1509.12, the permit provisions of section 1509.13 of the Revised Code, and all rules and orders of the chief relating thereto, in an amount set by rule of the chief.*

Recommendation No. 103: NYSDEC's financial assurance requirements should not narrowly focus on the cost for plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be included in the SGEIS as a mitigating measure, even if legislative action is ultimately required. Additionally, improved financial assurance should be codified in the NYCRR during this revision to the extent possible.

By comparison, Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well.[391] Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS.

[391] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

In addition to the bond amount, Fort Worth, Texas also requires the operator to carry multiple insurance policies:

1. *Standard Commercial General Liability Policy of at least $1,000,000 per occurrence. The Standard Commercial General Liability insurance must include: "premises, operations, blowout or explosion, products, completed operations, sudden and accidental pollution, blanket contractual liability, underground resources and equipment hazard damage, broad form property damage, independent contractors' protective liability and personal injury."*
2. *Excess or Umbrella Liability of $5,000,000;*
3. *Environmental Pollution Liability Coverage of at least $5,000,000 "applicable to bodily injury, property damage, including the loss of use of damaged property or of property that has not been physically injured or destroyed; cleanup costs; and defense, including costs and expenses incurred in the investigation, defense or settlement of claims…coverage shall apply to sudden and accidental, as well as gradual pollution conditions resulting from the escape or release of smoke, vapors, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste material or other irritants, contaminants or pollutants."*
4. *Control of Well Policy of at least $5,000,000 per occurrence/combined single limit with a $500,000 sub-limit endorsement for damage to property for which the Operator has care, custody and control; and*
5. *Other insurance required by Texas (e.g. Workers Compensation Insurance, Auto Insurance, and other corporate insurance required to do business in the state of Texas).*[392]

Financial assurance requirements should be increased to address worst-case risk exposure. Risk assessments should include worst-case scenario financial impact models. The risk modeling should be used to set higher financial assurance requirements.

Recommendation No. 104: The financial assurance requirements at 6 NYCRR §§ 551.5 and 551.6 are insufficient to address the risks to NYS and private parties associated with oil and gas development. It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment.

[392] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

26. Seismic Data Collection

Background: In 2009, HCLLC recommended that NYSDEC improve the DSGEIS and establish regulatory requirements for seismic data collection to reduce impacts to the environment and the public. The 2009 DSGEIS addressed naturally occurring seismic events in Chapter 4, but was silent on the impacts from industrial seismic exploration, which is used to locate subsurface gas reservoirs including shale gas targets.

This problem persists in the 2011 RDSGEIS. The 2011 RDSGEIS discusses naturally occurring seismic events, and seismically induced fractures from HVHF operations, but does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys used to target hydrocarbon formations for exploration and appraisal drilling. These seismic surveys are also useful to identify major fault systems to be used in HVHF design and modeling. Improved understanding of the subsurface stratigraphy and fault systems will improved 3D model simulation predictions and can aid engineers in designing HVHF treatments that do not link induced fractures with existing, conductive, natural fault systems that could move HF fluids into protected groundwater resources or water wells.

In January 2011, NYS' consultant, Alpha Geoscience provided a misguided recommendation to NYSDEC to ignore seismic data collection mitigation in the RDSGEIS, as "irrelevant."[393] Because seismic data collection is typically the first step in unexplored areas, to locate and optimize exploration drilling targets, seismic data collection mitigation when used to target Marcellus Shale wells is hardly "irrelevant."

Therefore, it is unclear whether NYSDEC is not familiar with the use of seismic data collection to target hydrocarbon formations for drilling, and the mitigation measures needed because its consultants advised against study of this important mitigation, or whether shale gas operators have told NYSDEC that they don't intend to collect two-dimensional (2D) or three-dimensional (3D) seismic surveys prior to exploring in the Marcellus Shale.

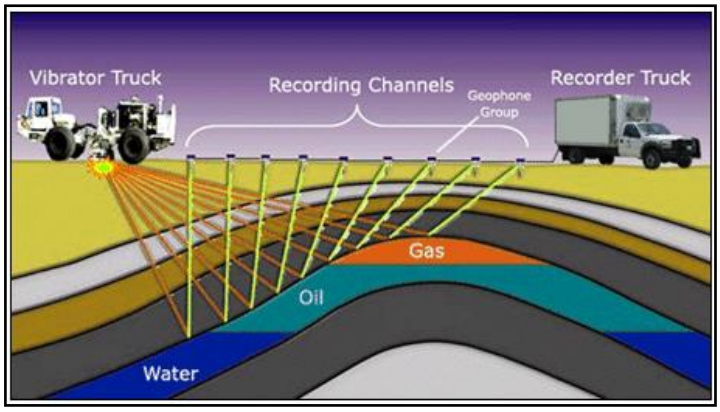
If operators do not intend to collect additional 2D and 3D data, that representation should be stated in the RDSGEIS, and the 2D and 3D data collection should be precluded in NYS. Otherwise, the impacts of this work should be identified and mitigated. This is an important issue to resolve, because seismic surveys can create significant surface impacts and disruptions.

Recommendation No. 105: If 2D or 3D seismic surveys are planned, or are possible in the future, the NYCRR should codify a permitting process for these activities and institute mitigating measures in the SGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas.

Exploration for oil and natural gas typically begins with a geologic examination of the surface structure of the earth, to identify areas where petroleum or gas deposits might exist. Once a geologist/geophysicist has identified an area of potential interest based on surface geologic maps, seismic data collection is typically obtained to identify possible subsurface hydrocarbon traps and structures.

[393] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011.

Seismic exploration equipment is used to send seismic waves into the earth. Seismic waves are generated by a surface positioned source and are measured by a surface positioned receiver. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Collecting seismic data in this manner is called a Reflection Seismic Survey.[394]



A reflection seismic survey involves generating hundreds to tens of thousands of seismic source events, or shots, at various locations in the survey area. The seismic energy generated by each shot is detected and recorded by sensitive receivers ("geophones" on land and "hydrophones" under water) at a variety of distances from the source location. Geophones and hydrophones are connected by long cables to relay the collected information back to a centralized computer. The photo to the left is a geophone and cable system.[395]

For every source event, each geophone generates a seismogram or trace, which is a time series representing the earth movement at the receiver location. A record of all traces for each shot is transmitted to a computer for storage and conversion into a seamless cross-sectional representation of the subsurface for subsequent study and interpretation by a trained geophysicist.

Onland seismic operations involve generation of seismic vibrations by explosive energy sources or by mechanical sources. One type of energy source for seismic exploration is an explosive charge. Small holes ("shot-holes"), typically 4 inches in diameter are drilled into the earth surface, 10-60' deep depending on surface terrain.[396] Although, some drill holes have been drilled to 200'.[397] The photo to the right shows an example of a shot-hole drill unit.

[394] U.S. Geologic Survey, Seismic Data Acquisition.

[395] Geophone and cable photo from http://www.anr.state.vt.us/dec/geo/newbedu.htm, State of Vermont.

[396] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

[397] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

The hole must be drilled into a hard layer of soil that is sufficiently dense to carry the seismic wave.[398] Explosive charges (typically 5-50 pounds each)[399] are lowered into the hole and detonated to create a shock wave (vibration). Some states have limits on the size of charges that can be deployed near environmentally sensitive areas, human inhabitation and near roadways.

Historic use of explosives on the ground surface resulted in large craters and extensive surface damage. Explosive charges are no longer deployed at the surface. Instead, a shot-hole must be drilled and the explosive lowered into the shot-hole at a sufficient depth to prevent surface craters. Shot-holes are filled with cuttings, bentonite and rocks to minimize surface impact.

Mechanical vibrators are an alternative to the use of explosives, and are more commonly used. Mechanical vibrators provide more consistent source strength and repeatability, and they are more reliable in the case of repeat data acquisition programs or for time-lapse studies.

Mechanical vibrators can include: a pad that thumps the surface of the earth ("thumper trucks"), driven by gravity or compressed air; a truck that generates vibrations ("Vibroseis™ Truck"); and compressed air guns.[400] The photo to the right shows a Vibroseis Truck. The Vibroseis method involves a truck equipped with vibrator pads that are lowered to the ground and triggered. Depending on the subsurface target depth and the purpose of the seismic survey, two or more seismic Vibroseis Trucks (vibrating in sync) may be needed.

In cold climates, ice road construction and use of Vibroseis Trucks for seismic data acquisition is the norm. Seismic data is typically secured over the winter months along ice road routes, to reduce footprint and stress to sensitive areas of the tundra environment.

The use of thumper trucks is not considered best practice because it involves dropping a steel slab that weighs about three tons to the ground to create a seismic vibration. Thumper trucks are large, requiring extensive tree and vegetation removal, and leave land scars.

In areas where seismic data is collected in water, the energy source is usually compressed air in an airgun submerged underwater, because explosives can cause adverse impacts to aquatic life.

[398] The Pembina Institute, Seismic Exploration, www.pembina.org.

[399] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

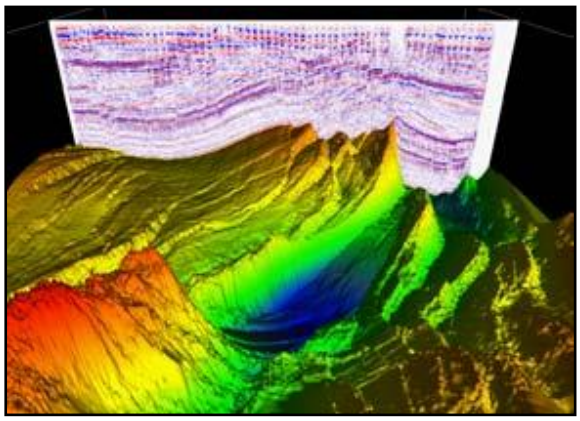
[400] Petroleum Engineering Handbook, Reservoir Engineering and Petrophysics, Volume V(A), Society of Petroleum Engineers, 2007.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (as shown in the photo to the left). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection. The width of each cutline depends on the seismic survey method used, but can be on the order of 20'-50' wide where large seismic equipment units are required. Best practice is to decrease the width of the cutlines to as small as possible using hand carried equipment. More recently companies have been able to reduce cutline width to 6'-10' in certain circumstances.

The spacing between each cutline is dependent on the type of seismic equipment used and depth of examination into the earth. The distance between each cutline is typically 300' apart (shallow reservoir targets) to 3,000' apart (deeper reservoir targets).[401]

Depending on existing development, infrastructure and access in the area planned for onshore seismic exploration, a seismic operator may need to build access roads, set up temporary camps and establish helicopter landings to bring in personnel and equipment. In areas where there are existing roads, housing and airports, surface disturbance can be minimized.

A basic set of seismic data can be obtained by setting a two dimensional array of seismic sources and receivers (2D seismic). Typically 2D seismic requires seismic lines tens of miles apart. Often 2D data is acquired along existing roads or access routes to minimize surface impacts. Along the 2D seismic cutlines shot-points and receivers are evenly spaced to send and receive a signal. This process produces a 2D slice of the subsurface.



If funding is available, operators generally opt to collect three dimensional seismic (3D seismic) images of the subsurface. 3D seismic data acquisition involves a much more intensive data collection effort, using multiple shot lines arranged perpendicular to multiple receiver lines of geophones, with seismic lines spaced several hundred feet apart, rather than miles apart.[402] An example of a map produced from a 3D seismic survey is shown to the left.

Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions. None of these impacts have been analyzed in the NYS RDSGEIS.

There are typically six different crews deployed: (1) access crews, that clear seismic lines, (2) "shooters" that drill the shot-holes and set the explosive charges or run the mechanical vibration equipment to generate seismic waves, (3) "recorders" that set the geophones and measure the seismic reflection, (4) the "pick-up" crews that move the equipment from one location to the next along the seismic lines,

[401] The Pembina Institute, Seismic Exploration, www.pembina.org.

[402] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

(5) logistical support crews that provide housing, food, medical, maintenance and repair, and transportation; and (6) remediation and plugging crews that restore the area and plug shot-holes (if used).

Recommendation No. 106: The increased industrial activity (e.g. economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the SGEIS.

In 2011, HCLLC developed a report for NRDC and Sierra Club describing the types of impacts that occur from 2D and 3D seismic surveys, and made recommendations for best practices and model permit requirements. The recommendations in this report could be considered by NYSDEC in crafting seismic survey requirements for NYCRR.[403]

Recommendation No. 107: Consider the best practices and model permit requirements proposed in Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011, for inclusion as mitigation measures in the SGEIS and improvements in the NYCRR to regulate seismic survey data collection.

[403] Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011.

APPENDIX A

Surface Casing Table

Appendix A - Surface Casing Table

Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Setting Depth	75' beyond the deepest fresh water zone encountered or 75' into competent rock (bedrock), whichever is deeper.	100’ below the deepest freshwater zone and at least 100’ into bedrock.	No requirement listed; assume it defaults to the Appendix 8 requirement of 75'.	The Appendix 10 HVHF surface casing setting depth requirement is less stringent than the Appendix 9 requirement; both should be 100'. NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether the setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths.	Surface casing must be run in all wells to extend below the deepest potable fresh water level. Neither the 75' nor the 100' setting depth below the deepest protected water zone is specified in the NYCRR.	No additional requirement.	NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.
Protected water depth estimate and verification	No requirement.	Estimated in drilling application and verified while drilling.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.
Cement Sheath Width	No requirement.	At least 1-1/4".	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

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Amount of Cement in Annulus	Not specified, but it is presumed that the goal is to complete annulus cementing, because the requirements include 25% excess cement; however, the conditions require a reporting of the cement top location, if cement is not returned to the surface, which indicates that NYSDEC could accept a partially cemented annulus.	Entire annulus must be cemented; cement squeeze may be required.	No requirement listed; assume it defaults to Appendix 8 requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus.	There is a requirement to circulate cement to the top of the hole.	No additional requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.
Shallow gas hazards	Surface hole drilling must stop and surface casing must be set and cemented before drilling deeper into hydrocarbon resources.	The likelihood of shallow gas hazards must be estimated in the drilling application and verified while drilling.	No requirement listed; assume it defaults to Appendix 8 requirement.	All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. If a shallow gas hazard is encountered, surface casing should be set and cemented to protect water resources, before drilling deeper into hydrocarbon resources.	No requirement.	No requirement.	If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.
Excess Cement Requirement	25%	50%	No requirement listed; assume it defaults to Appendix 8 requirement of 25%.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume.	No requirement.	No requirement.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

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Cement Type	The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content and contain a gas-block additive.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.
Lost Circulation Control	Required.	Required.	Required.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

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Spacer Fluids	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	Required.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Hole conditioning before cementing	Gas flows must be killed or lost circulation must be controlled and the hole be conditioned before cementing.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	At least every 120', with a minimum of two centralizers. A table of centralizer-hole size combinations is included.	At least every 120'.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

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Casing quality	All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi); used casing may be approved for use, but must be pressure tested before drilling out the casing shoe.	New pipe with minimum internal yield pressure (MIYP) of 1,800 psi, or reconditioned pipe that has been tested internally to a minimum of 2,700 psi, must be used.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.	No requirement.	All casing must be new and conform to the industry standards specified in the permit to drill.	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.	No requirement.	Casing thread compound and its use must conform to the industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

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Drilling Mud	No requirement.	Compressed air or WBM, no SMB or OBM.	Not listed in Appendix 10, but the RDSGEIS text includes a section that states compressed air or WBM should be used on HVHF wells.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells, not just those described in Appendix 9.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.
Cement Setting Time	Compressive strength standard of 500 psi.	No requirement listed; assume it defaults to Appendix 8 requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.
NYSDEC Inspector	No requirement.	Required to be onsite for cementing operations.	No requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation.	No requirement.	No additional requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

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Cement QA/QC - Cement Evaluation Log	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	No requirement listed; assume it defaults to Appendix 8 requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.	No requirement.	No additional requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.
Formation Integrity Test	No requirement.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

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BOP Installation	Confirmation that the surface casing is set and cemented into place, such that the BOP can be secured and effective when drilling deeper into the well.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP.	No requirement.	No requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	Not specified.	Not specified.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the Department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

APPENDIX B

Intermediate Casing Table

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Waiver Provision to Exclude Use of Intermediate Casing	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.	No requirement.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.
Setting Depth	No requirement.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.
Protected Water Depth Estimate and Verification	No requirement.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.
Amount of Cement in Annulus	No requirement.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.
Excess Cement Requirement	No requirement.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

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Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	No requirement.	No requirement.	Cement slurry must be prepared to minimize its free water content, in accordance with industry standards and specifications.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used , not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

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Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	No requirement.	No requirement.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers, must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.
Casing quality	No requirement.	No requirement.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Drilling Mud	No requirement.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.
Cement Setting Time	No requirement.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

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NYSDEC Inspector	No requirement.	No requirement.	Required to be onsite for cementing operations.	Best practice is to have a state inspector onsite during cementing operations.	No requirement.	No requirement.	Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	No requirement.	No requirement.	No requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	No additional requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

APPENDIX C

Production Casing Table

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Design	No requirement.	No requirement.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.	The drilling, casing and completion program adopted for any well shall be such as to prevent the migration of oil, gas or other fluids from one pool or stratum to another.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No additional requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where production casing is set.
Amount of Cement in Annulus	The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.	No additional requirement. Appendix 8 requirement would apply.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice.	If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Excess Cement Requirement	A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	No additional requirement.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	No additional requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No additional requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Installation and Pump Rate	The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.	No additional requirement. Appendix 8 requirement would apply.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. The pump and plug installation method is a best practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will be come more difficult with a deviated wellbore, but should be attempted if achievable.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.
Centralizers	Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval.	No additional requirement. Appendix 8 requirement would apply.	At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002)	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.
Casing quality	The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.	No additional requirement. Appendix 8 requirement would apply.	Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited.	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.