STATE OF NEW YORK
EXECUTIVE CHAMBER
ALBANY 12224

April 20, 2012

Thomas Cluderay
Assistant General Counsel
Environmental Working Group
1436 U Street NW, Suite 100
Washington, DC 20005

Dear Mr. Cluderay:

We have received your check for $21.50 to cover photocopying fees for documents that respond to your Freedom of Information Law request dated March 6, 2012..

Enclosed please find the responsive documents referenced in my letter dated April 10, 2012.

As a result of the foregoing decision you have a right to appeal pursuant to Public Officers Law §89(4). Your written appeal must be submitted no later than 30 days after you receive the requested documents to: FOIL Appeals Officer, Executive Chamber, State Capitol, Albany, New York 12224.

Very truly yours,

Justin C. Levin
FOIL Counsel
Records Access Officer

Enclosures

Thomas Irvin

Subject:	Chesapeake Energy
Location:	245 Conference Room
Start:	Thu 3/1/2012 2:00 PM
End:	Thu 3/1/2012 2:45 PM
Show Time As:	Tentative
Recurrence:	(none)
Meeting Status:	Not yet responded
Organizer:	Caron Palladino

UPDATE: Meeting Subject Matter
Topic:

1. Recent Home Rule Decisions
2. Hazardous Waste Classification Legislation

Day/Date: Thursday, March 1
Time: 2:00 – 2:45pm
Location: 245 Conference Room

Attendees:
Robert Hallman – Executive Chamber
Tom Congdon – Executive Chamber
Tom West – The West Firm
w/client: Paul Hart – Chesapeake Energy

Executive Chamber Contact:
Tracy Prevratil: 473-5442

Testimony of Paul Hartman
Director of State Government Relations
Chesapeake Energy Corporation

Before the New York State Senate Committee on Environmental Conservation
Public Hearing on Waste Water and Drill Cuttings Produced From Natural Gas Development

December 12, 2011

Chairman Gristani and members of the Senate Environmental Conservation Committee, thank you for the opportunity to address you today on the matter of produced water and drill cuttings disposal as it relates to natural gas drilling and hydraulic fracturing. My name is Paul Hartman. I am the Director of State Government Relations for Chesapeake Energy Corporation.

Chesapeake Energy Corporation is the second largest producer of natural gas, a top 15 producer of oil and natural gas liquids and the most active driller of new wells in the United States. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Haynesville, Bossier, Marcellus and Pearsall natural gas shale plays and in the Granite Wash, Cleveland, Tonkawa, Mississippi Lime, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford Niobrara, Three Forks/Bakken and Utica unconventional liquids plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling, trucking, pressure pumping and other oilfield service assets.

Due to time constraints, my testimony today will focus on Chesapeake's water recycling and reuse program – Aqua Renew.

Water is an important and highly valued resource and Chesapeake takes its use very seriously. First, I'd like to share with you a couple of important facts. It is very rarely reported and often overlooked that deep shale natural gas is one of the most water efficient energy resources. Producing natural gas uses 5 times less water than what is used to produce coal and 1000 times less than what is used for ethanol.

One of the major advances in the process of developing our natural gas resources in recent years that has resulted in significant conservation of our water resources is the advent of recycling and reuse of flowback and produced water by the industry. In recent years, water recycling, particularly in neighboring Pennsylvania, has been transformed from a trend to an essential operational procedure.

Recycling produced water reduces the impact on local water supplies, which translates into less truck traffic which means reduced road infrastructure wear and tear from water tanker trucks.

Founded under the concept of water recovery and reuse, Chesapeake's Aqua Renew program is utilizing state-of-the-art technology in an effort to recycle produced water. This naturally occurring water is generally laden with various minerals and travels from the producing formation through the wellbore to the surface with natural gas during the completion and production operations. The quality of produced water differs greatly with varying amounts of salt, sand or silt, depending on the formation in which it is found. Due to its normally high salt content, reuse in completion operations had been considered impossible by the industry for a long time.

Chesapeake began to intently focus on water reclamation and conservation after a 2006-2007 drought in the Barnett Shale in Texas. The drought had an obvious affect on Chesapeake's drilling and completion activities, to accompany the impacts on other industries and residents throughout the region. From that experience, and Chesapeake's involvement in the Barnett Shale Water Conservation and Management Committee, the company entered into an agreement with the City of Fort Worth to study water evaporation systems as a potential way to reduce the amount of produced water being injected into saltwater disposal wells, which was the preferred disposal technique. Using an Evaporative Reduction and Solidification System (EVRAS) to capture heat generated by natural gas compressor stations, an energy source that would typically be wasted,a portion of the produced water is then filtered and reduced to water vapor. The resulting clean vapor is then released into the atmosphere where it enters the normal hydrologic cycle.

Since this preliminary reclamation project, Chesapeake's focus on reuse and water conservation has become a company-wide endeavor, stretching from the Barnett Shale in North Texas to northern Pennsylvania. In fact, the Aqua Renew program is helping to change the long-standing industry assumptions that produced water is unusable. As referenced previously, it was a long-standing industry supposition that using anything other than freshwater with a clay control additive down hole would harm the ultimate potential of the well. As a result, operators had previously only used freshwater resources in drilling and completion procedures. Chesapeake decided to challenge and tests that theory and see if it was true or if there was in fact a limit to how much recycled water could be used without compromising the well production.

At each well site, produced water is collected and stored in on-site holding tanks before being transferred to central filtration locations. Our current methods of fluid treatment use both chemical and physical methods. The fluids from our drilling operations are treated though a filter press, which requires some chemical additions to adjust fluid parameters such as pH. Aqua Renew also uses flocculating agents to assist in removing the solids from the fluid. The physical treatment utilizes a back washable system, which filters out the suspended solids larger than 20 microns.

The filtered water is then either stored in on-site tanks or transported to the next well scheduled for hydraulic fracturing, commonly referred to as fracing. The water is tested for salt content and total hardness to determine the rate at which it can be blended with freshwater to ensure proper quality and quantity for reuse.

Chesapeake still has to mix the recycled produced water with freshwater in order to ensure the proper mixture for fracturing, but every gallon of produced water filtered and reused is one less gallon of water that has to be permitted disposal location or facility and one less gallon of fresh water that has to be sourced.

To date, Chesapeake still hasn't found a limit for the reuse of recycled water. In fact, the company's northern and central districts of its Eastern Division operations are treating and recycling 100% of the initial produced water from the flowback process. We believe that water can be recycled indefinitely as it is mixed with fresh water during the fracturing process.

The fracturing process uses an average of 6 million gallons of water per well, depending on several factors such as the number of stages of fractures to be completed in the lateral of the well.

Through the second quarter of 2011, Chesapeake had four Aqua Renew sites recycling drilling and production fluids in Pennsylvania under a OG71 permit issued by the Department of Environmental Protection (DEP) Oil & Gas Division. This past summer, the Commonwealth changed the permit requirement to require a new permit – the WMGR-123 permit - which is managed by the Waste Management Division of the Pennsylvania DEP. All future fluid processing sites will require the WMGR-123 permit. I have included a copy of this permit with my testimony for your reference. The OG71 permit will remain available in Pennsylvania; however allowable activities under this permit will be limited to the utilization of the recycled water on the well pad at which it was processed.

Chesapeake has established a program of periodic measurement of the radioactivity of the recycled water and has found no increase in radioactivity over the background data. We also measure the radioactive level of every load of solids which has been filtered from the produced waters (as required per our permit) and have found no load of solids which exceed the limits set under the state operating permit. Currently, all filtered solids are trucked to a rail siding in Meshoppen, PA and taken to Ohio for disposal in a landfill. The filtered solids are once again checked for abnormal radioactivity at the landfill before final disposal.

On average, this process is able to filter and reuse more than 10 million gallons of produced water a month in Marcellus Shale fracturing operations. In 2010 alone, Chesapeake recycled 83 million gallons of produced water. With such large volumes of recycled water, the company is seeing more than just environmental advantages. Our accounting department has estimated that this aspect of the process is saving an average of $12 million a year in the Eastern Division alone. The program is garnering results like these throughout our shale plays and subsequently the Aqua Renew program is expected to continue to grow.

Chesapeake is always evaluating new technology on our own and through partnerships like the one we have with the Barnett Shale Water Conservation Group and others. Currently, in Pennsylvania our biggest challenge to enhancing our recycling and reuse efforts is obtaining the permits for the development of additional fluid processing sites, and avoiding the potential for exceeding current filtration capacities.

However, I must take this opportunity to appeal to the Committee that innovation and technological advancement are only possible through a flexible regulatory and statutory regime that does not lock industry into yesterday's technology, best practices or common practices. In April of this year, the PA DEP requested that all natural gas drilling operators cease delivering wastewater from shale gas extraction to permitted wastewater treatment facilities in the Commonwealth. Chesapeake and all operators active in the Marcellus

Shale Coalition have made extensive efforts to meet that objective, predominately through the expansive reuse and recycling of produced water. Meeting the goal of near universal recycling and reuse can be impeded by burdensome and overly prescriptive regulations or legislatively stipulated best management practices. I would advise the Committee to examine the overall impact of any new proposals in regards to wastewater treatment, recycling and reuse to determine the effectiveness of the policy and the creation of any additional barriers to sound water management and conservation practices that have been developed by industry leaders such as Chesapeake over the past several years.

Please remember that only 5-6 years ago, the conventional wisdom dictated that produced water could not be recycled and reused and today, in our Marcellus North operations, we are in fact recycling and reusing 100% of the initial produced water from the flowback process.

In closing, it is with great pride that Chesapeake can share with you that the filtration/recycling process we are utilizing is working quite well in Pennsylvania. The utilization of recycled water in our fracturing process has not had negative impact on well productivity and our fluid waste treatment capability creates a closed loop system which has no impact to the fresh water, rivers and streams in Pennsylvania.

I thank you for the opportunity to address the Committee today on this important issue. Please rest assured that Chesapeake stands ready to assist the Chairman and the Committee on this and any other issue pertaining to the responsible development of our natural gas resources.

Chesapeake ENERGY

Mike Brownell
Senior Director – State Environmental and Regulatory Affairs

Commissioner Joseph Martens
Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Re: Comments on (1) Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program ("rdSGEIS"), (2) Proposed Regulations Regarding High-Volume Hydraulic Fracturing ("Proposed HVHF Regulations"), and (3) Proposed State Pollutant Discharge Elimination System General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing ("Proposed SPDES General Permit")

Dear Commissioner Martens:

Chesapeake Energy Corporation ("Chesapeake") is the second-largest producer of natural gas and the most active driller of new wells in the United States. Using state-of-the-art techniques, Chesapeake focuses on discovering and developing unconventional onshore gas fields in a safe, efficient, and environmentally-friendly manner. As a result, it is at the forefront of developing some of the country's (and, therefore, the world's) largest gas fields, including the Marcellus, Haynesville, Barnett, and Bossier shale plays. Chesapeake believes that domestic natural gas – a clean-burning fuel that is extraordinarily plentiful in the United States – can become the primary solution to many of the country's most challenging environmental and energy issues.

New York is the location of a large portion of the Marcellus shale, and Chesapeake holds substantial gas lease acreage there. Chesapeake, therefore, has a strong interest in the manner in which the state regulates the exploration and development of natural gas.

Chesapeake thanks the New York State Department of Environmental Conservation ("DEC") for its consideration and the opportunity to submit these comments on the rdSGEIS, proposed HVHF regulations, and the proposed SPDES General Permit. Additionally, Chesapeake has been working with the Independent Oil and Gas Association of New York ("IOGA NY") and supports the comments submitted by IOGA NY to the DEC on the rdSGEIS and the associated proposed regulations.

We hope that they will be received and accepted in the spirit in which they are offered – that is, in the hope of improving the draft regulatory package in order to establish standards that are protective of New York's environmental resources while at the same time allowing for efficient development of the valuable shale gas resources that are vitally important to New York and the nation.

Given the long-term projections of low natural gas prices, as well as the existence of more profitable plays and more reasonable regulatory environments on federal lands and in neighboring states, it is difficult to foresee industry making the significant investments necessary to develop the shale gas resources in New York if the excess costs and delays in this draft are not addressed. As a result, Chesapeake is deeply concerned that the proposed requirements, if adopted in their present form, would effectively kill natural gas development from shale formations in New York State.

Sincerely,

M G Brownell

Michael G. Brownell

Senior Director, State Environmental and Regulatory Affairs

Chesapeake Energy Corporation

6100 N. Western Avenue

Oklahoma City, Oklahoma 73118

Tom West
2/1/12 [redacted]

PREEMPTION OF LOCAL LAWS [redacted]
UNDER ECL § 23-0303(2)

Local municipalities do not retain any authority to regulate the oil and gas industry through land use (i.e., zoning) or other local laws purportedly based on public health, safety and welfare.

Plain language

> The provisions of this article *shall supersede all local laws or ordinances relating to the regulation of the oil, gas and solution mining industries*; but shall not supersede local government *jurisdiction* over local roads or the rights of local governments under the real property tax law. ECL § 23-0303(2) (emphasis added).

On its face, this provision is a broad, all encompassing directive that limits the regulation of oil, gas and solution mining industries to the exclusive provenance of the Department of Environmental Conservation ("DEC"). Significant in this regard is the language referencing supersedure of "local laws or ordinances." Of course, the most common type of ordinance is a zoning ordinance. By its plain language, the statute's express exclusion of two discrete subject areas (i.e., roads and property taxes) renders all other matters that are related or subject to the oil, gas and solution mining industry within the scope of this supersedure provision. And the fact that the statute speaks to limiting the "jurisdiction" of municipalities to these discrete areas is further evidence of the broad preemptive effect.

The "regulation" of the oil, gas solution mining industry is determined by Article 23 of the ECL, its implementing regulations and the GEIS as is currently being supplemented by the DEC. And, telling, this includes the location of wells.

Legislative Intent

New York's Oil, Gas and Solution Mining Law was enacted to appropriately regulate in a uniform manner across the state the development, production and utilization of oil and gas resources in order to prevent waste, maximize recovery and protect the correlative rights of all landowners and the general public.

It was amended in 1981 to address the litany of problems facing the industry, specifically including those concerning local control. In exchange for local preemption, municipalities were given two "carrots:" (1) an oil and gas fund to compensate local governments for damages related to oil and gas activities; and (2) an ad valorem tax authorizing local municipalities to levy a real property tax on oil and natural gas based upon production. [redacted]

New York Policy Objectives

In not one, but two places, New York law encourages the development of the State's indigenous natural resources. The overarching policy objectives of the State to prevent waste and maximize recovery of the State's indigenous energy resources are established, not just in ECL § 23-0301 but, also, in Energy Law § 3-101(5).

ECL § 23-0301:

> It is hereby declared to be in the public interest to regulate the development, production and utilization of natural resources of oil and gas in this state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected[.]

Energy Law 3-101(5):

> It shall be the energy policy of the state ... to *foster, encourage and promote* the prudent development and wise use of [limited] *all indigenous state* energy resources *including, but not limited to, on-shore oil and natural gas, off-shore oil and gas, natural gas from Devonian shale formations*[.] (emphasis added).

New York Case Law

The New York courts have already addressed the scope of the preemption provision of ECL § 23-0303(2). *See Matter of Envirogas, Inc. v. Town of Kiantone*, 112 Misc. 2d 432, 435 (N.Y. Sup. Ct, Erie Cty 1982), *aff'd* 89 A.D.2d 1056 (4th Dep't 1982), *app. den.*, 58 N.Y.2d 602 (1982). In *Envirogas*, the Court found that ECL § 23-0303(2) expressly "pre-empts not only inconsistent local legislation, but also *any* municipal law which purports to regulate gas and oil well drilling operations, unless the law relates to local roads or real property taxes which are specifically excluded by the amendment." *Id.* (emphasis supplied).

Mining Precedent is Inapt

The holding in *Frew Run*, although unfavorable for New York's extractive mining industry at the time, is irrelevant to the preemption issue in the context of the oil and gas industry.

Although the two statutory provisions begin with similar preemption language, they have differing statutory exceptions and the preemption provision at issue in *Frew Run* applies to a wholly distinct regulatory program (excavation mining) with significant, long-lasting surface impacts. Indeed, the operative language at that time for mining was as follows:

> For the purposes stated herein, this title shall supersede all other state and local laws relating to the extractive mining industry; *provided, however, that nothing in this title shall be construed to prevent any local government from enacting local zoning ordinances or other local laws which impose stricter mined land reclamation standards or requirements than those found herein.* (emphasis added).

Furthermore, it is clear from the legislative history for the Mined Land Reclamation Law ("MLRL") that local regulation was contemplated at the time the MLRL supersedure provision was enacted. In fact, representatives of the mining industry opposed this language before the Governor because it would invite local zoning.

Another major distinguishing feature is that extractive mining, unlike oil and gas drilling, is an industrial, consumptive land use. Oil and gas wells, on the other hand, have impacts that are temporal.

Furthermore, unlike in *Frew Run* where the Court determined that local zoning authority would *not* conflict or frustrate the statute's purposes, the same cannot be said for New York's Oil, Gas and Solution Mining Law, which purpose includes: "prevent[ing] waste," providing for the "greater ultimate recovery of oil and gas" and protecting correlative rights. ECL § 23-0301.

Finally, amendments to the MLRL were passed in 1991 to give clear authority to local governments to establish permissible uses in zoning districts and to require a limited special use permit. And, because of this clear legislative change to the MLRL supersedure provision, case law post-dating 1991 are simply irrelevant (*e.g., Matter of Gernatt Asphalt Products*).

Long-standing DEC Interpretation

For over thirty years, the Department has interpreted of ECL § 23-0303(2) to completely preempt local municipalities from regulating the oil and gas industry, whether through zoning or other local laws and ordinances putatively based on public health, safety and welfare.

Other States

Pennsylvania case law is irrelevant here given the markedly different language in the Pennsylvania's supersedure provision. The Pennsylvania Oil and Gas Act's preemption provision, unlike the OGSML clarifies that its preemptive scope is limited to local regulations that "contain provisions which impose conditions, requirements or limitations on the *same features of oil and gas well **operations** regulated by this act* or that accomplish the same purposes as set forth in this act;" and the statute again states that it "hereby preempts and supersedes *the regulation of oil and gas wells **as herein defined.***" 58 Pa. Cons. Stat. § 601.602 (emphasis added).

As for Colorado, where there is no express local preemption provision, no local law has yet to be upheld when challenged on conflict preemption grounds. The highest court in Colorado has struck down a complete ban on drilling and, to date, found only that a local law which sought to promote the development of oil and gas drilling could potentially be harmonized and thus, not struck down, pending further factual development by the lower court.

Furthermore, the most recent case from outside New York that addresses the interplay of home rule powers and a state's interest in regulating the oil and gas industry is from West Virginia. *See Northeast Natural Energy, LLC v. City of Morgantown, W.V.*, Civ. Action No. 11-C-411, (Cir. Ct., Monongalia Cnty., WV, Aug. 12, 2011). There, the court found the city's ban to be preempted and an impermissible attempt to "regulate oil and gas development." *Id.* at 9.

2/29/12

Chesapeake ENERGY

MEMORANDUM IN OPPOSITION
A7013 (SWEENEY) / S4616 (AVELLA)

AN ACT to amend the environmental conservation law, in relation to the uniform treatment of waste

Chesapeake Appalachia, LLC, a wholly owned subsidiary of Chesapeake Energy Corporation ("Chesapeake") opposes the enactment of this legislation.

The bill would amend Section 27-0903 of the Environmental Conservation Law to remove a long-standing, exemption from the hazardous waste regulations for waste produced by the exploration, development and production of crude oil and natural gas. While Chesapeake fully supports the Legislature's motivation to be protective of the environment, such regulations should be based on sound science, not the irrational claims of drilling opponents. This bill would require a level of waste regulation that both federal and state environmental regulators have determined to be unnecessary, and which, in fact, sets up a regulatory scheme that is unconstitutional. In addition, the legislation is far too broad and would unintentionally impact all types of natural gas drilling, not just the horizontal drilling/high-volume fracturing methods proposed for the Marcellus Shale play. For these reasons, and as further explained below, Chesapeake opposes this legislation.

There Are No Documented Problems with Drilling Wastes

First and foremost, Chesapeake believes the Legislature should let the New York State Department of Environmental Conservation ("DEC") complete its ongoing study of the potential environmental impacts related to drilling in the Marcellus Shale. The NYSDEC released its revised Draft Supplemental Generic Environmental Impact Statement ("SGEIS") in July of 2011 and it is anticipated that the review process will be completed later this year. Importantly, the current draft of the SGEIS document (which is over 1500 pages in length) clearly demonstrates that NYSDEC has fully considered all waste streams produced by natural gas drilling, both in New York and other gas producing states, and concluded that the existing regulations are sufficiently protective of public health and the environment. Rather than regulate drilling wastes as hazardous wastes (which they are not), the DEC regulates these wastes as industrial wastes and is proposing to employ many of the same regulatory controls that are used with hazardous waste to ensure the safe handling and processing of these materials. These include a manifest system to track the wastes from cradle to grave and the requirement that all transporters be permitted under the Part 364 waste transporter program. There are approximately 14,000 operating wells in New York State. All of these wells have been stimulated with chemicals and many of the wells have been stimulated with hydraulic fracturing. And, notwithstanding this high volume of activity, there are no documented cases of drilling wastes creating any problem in

New York State. As such, there is no justification for this legislation, which is nothing more than a transparent attempt to forestall the development of our indigenous natural gas resources.

In addition to the SGEIS process, NYSDEC has also specifically reviewed the potential environmental impacts from drill cuttings, one of the wastes associated with the drilling process, and determined that these wastes are acceptable for landfill disposal. *See, In the matter of Chemung County,* Commissioner's Decision, August 4, 2011. Accordingly, a number of facilities in New York are currently accepting drill cuttings from Marcellus Shale drilling in Pennsylvania. This is yet a further example of why this legislation is not necessary.

Moreover, the regulatory exemption that this bill seeks to set aside has been the policy of the federal Environmental Protection Agency ("EPA") for over thirty years, since the agency created the initial hazardous waste regulations under the Resource Conservation and Recovery Act ("RCRA"). Importantly, in the course of its regulatory review, EPA thoroughly considered whether wastes from the exploration, development and production of crude oil, natural gas and geothermal energy should be regulated as hazardous waste. After careful consideration of the issue over a number of years, EPA issued a Report to Congress and made a regulatory determination that subjecting such wastes to regulation as hazardous waste was unwarranted. It is not an understatement to say that the regulatory status of these wastes has been on EPA's agenda for *over thirty years.* Notwithstanding widespread and longstanding use of both horizontal drilling and hydraulic fracturing in the United States (the first hydraulically stimulated wells were drilled in the early 1900's), EPA has never revised its regulatory determination with respect to these wastes. In fact, EPA's current research plan (draft released February 2011) to study the effects of hydraulic fracturing on drinking water resources—which was mandated in response to Congressional concerns about modern drilling practices—*does not question the regulatory status of drilling wastes.*

This Legislation is Unconstitutional and Arbitrary

Further, given the strong federal underpinnings in the area of hazardous waste/hazardous materials regulation, it is very likely that this bill would be unconstitutionally void upon enactment. Simply put, regulation of federally exempt materials as hazardous waste in New York would result in an undue burden on interstate commerce, since the regulations would irreconcilably conflict with RCRA and the Hazardous Materials Transportation Act. In particular, drilling waste generators and transporters would be potentially subject to enforcement in New York State where they are otherwise in full compliance with the comprehensive federal programs. The issue is especially problematic given the interstate nature of hazardous waste disposal, since these materials are frequently transported to out-of-state facilities for treatment, storage or disposal.

The proposed legislation also raises constitutional equal protection concerns. While the existing regulatory exemption addresses "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy," this bill arbitrarily singles out oil and gas drilling wastes for regulation as hazardous waste. There is no rational basis to distinguish these wastes from those produced by drilling for geothermal wells.

The Legislation Creates an Undue Financial Burden and Permitting Delays

This legislation would require the Department to "make all necessary changes to bring its relations into compliance". It can be anticipated that the activist community will press for public hearings and a public relations campaign designed to ensure that produced wastes are reclassified from their current industrial waste status to hazardous waste. This process will add months if not years to the current four-year long SGEIS process, even without the much-anticipated litigation from the activist community. Additionally, once the current industrial waste stream is reclassified and all cuttings, mud and produced water/fluids are considered hazardous waste, drilling companies would be subject to significant increases in the cost of their operations, futher making development in New York State economically infeasible at current and future natural gas prices.

On a per well basis, Chesapeake has calculated the fiscal impact of this legislation based upon Marcellus values experienced in Northeastern Pennsylvania, which are indicative of what to expect in New York. These estimates were based on the following costs: increased costs for disposal of cuttings and mud from drilling - $500,000 (low volume scenario) to $800,000 (maximum volume scenario) with an average volume scenario of $700,000; increased cost for produced water from flowback operations - $1.2 million to $7.2 million with an average estimated cost of $4 million; and increased cost for produced water from production operations (lifetime of the well) - $3.8 million to $8.7 million with average cost of $5.9 million. So, based on current operational costs for the disposal of hazardous solids and fluids, it is anticipated that this legislation could add an additional $5.5 million to $15 million to the cost of a single well over its lifetime.

10 mill Average

This reflects only the costs associated with the disposal process. These estimates do not include the additional assessments and fees that the industry would be subjected to as "hazardous waste generators" and "hazardous wastewater generators". These additional assessments and fees would add tens of thousands dollars in additional expense to operations.

The Legislation Inhibits Recycling and Reuse

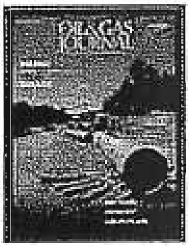
[redacted]

Last but not least, this bill would inhibit recycling by arbitrarily classifying these wastes as hazardous waste. Currently, the industry is recycling approximately 90% of the water produced as a result of the natural gas drilling and production process. Many companies have gone to 100% recycling. At hearings held by Senator Grisanti last fall, it was demonstrated that there are a number of proven technologies already in existence to process produced water into pure water and salt, similar to the road salt that is widely used across New York State.

Based on the above, Chesapeake opposes this legislation as lacking any sound scientific basis, constitutionally flawed, and overbroad. Chesapeake respectfully submits that the Legislature should leave the science and regulation of oil and gas development to the skilled and knowledgeable regulators at EPA and DEC.

For additional information about this legislation, please contact Paul Hartman, Director of State Government Relations at paul.hartman@chk.com or 518-477-3047.

Chesapeake is a leading independent producer of natural gas and the No. 1 driller of new wells in the United States. Chesapeake's presence in New York State commenced in 2005 when it acquired Columbia Natural Resources, which had a strong historical presence in the state.



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Close

Study projects Utica shale contributions to Ohio's economy

Development of the Utica shale will bring more than 65,000 jobs, contribute $4.86 billion to Ohio's economy, and result in $3.3 billion of labor income, or an average of $50,225/job, by 2014, a study commissioned by the Ohio Shale Coalition concluded.

A $229.6 million investment during 2011 in the Utica play raised the state's gross product, measured by value added, by $162 million, which translated into 2,275 jobs and nearly $100 million of increased labor income, researchers at Cleveland University, Ohio State University, and Marietta College found.

"Since updates in technology have made drilling in the Utica shale possible, people have been euphoric over the economic prospects of shale development in Ohio," said Linda Woggon, executive director of OSC, which the Ohio Chamber of Commerce formed in June to supply information about the shale oil and gas industry to Ohioans.

"Our goal was to take a very reasonable approach to the numbers and develop conservative projections," she indicated on Feb. 28 as the study was released in Columbus.

The study presents "a very conservative, baseline case" for the type of potential economic growth in Ohio from Utica shale development, observed Karen A. Harbert, president of the US Chamber of Commerce's Institute for 21st Century Energy. "Today's study and others recently released project significant new sources of jobs and revenue across Ohio and neighboring states which will contribute to increasing our nation's energy security and putting America back to work," she said.

The study's research team modeled a likely economic development impact model for Ohio from Utica shale development based on anticipated leasing, road construction, and well drilling and completion expenditures, and building of post-production gas infrastructure. The calculations include not only expenditures' direct effects, but also indirect (subsequent business) and induced (household spending) effects. The model shows average labor income rising over time as the work shifts from leasing and road construction to drilling and infrastructure maintenance.

It projected that nearly 17% of the additional jobs would come from oil and gas service companies, at a $69,000/year average per job, and employment doubling between 2013 and 2014. "The largest growth in employment will be in construction-related trades as wells are drilled and midstream facilities are constructed," the study said.

Another nearly 11,000 local construction jobs, paying an average of $48,000/year each, could be created from construction of new manufacturing facilities and other non-residential structures, including midstream infrastructure, as well as pipelines, roads, and bridges, it said. "Truck drivers will be in great demand as servicing companies, wholesalers, delivery services, and construction companies ramp up their employment to meet demand," it said.

The study's model estimated that by 2014, more than 1,500 jobs for engineers and architects and 1,000 positions for environmental compliance technicians will be established. There also will be demand for more than 1,800 office workers and nearly 500 technical consultants, it suggested. Managers earning an average $109,000/year will have the highest salaries, followed by consultants earning an average $75,000/year, it said. Petroleum landmen also will be in demand, although the study did not attempt to project how many will actually find work in Ohio.

Data is incomplete because the state's shale oil and gas industry is in its infancy, the study said. Models may be updated as more data becomes available, it indicated. "It is also important to note that the study term only goes to 2014, at which time the industry will likely yet be growing in Ohio," it said.

Contact Nick Snow at nicks@pennwell.com.

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Comments on (1) Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program ("rdSGEIS"), (2) Proposed Regulations Regarding High-Volume Hydraulic Fracturing ("Proposed HVHF Regulations"), and (3) Proposed State Pollutant Discharge Elimination System General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing ("Proposed SPDES General Permit")

Submitted to New York State Department of Environmental Conservation

By Chesapeake Energy Corporation

Chesapeake submits these comments to the New York State Department of Environmental Conservation ("DEC") regarding (1) the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program ("rdSGEIS"), (2) the Proposed Regulations Regarding High-Volume Hydraulic Fracturing ("Proposed HVHF Regulations"), and (3) the Proposed State Pollutant Discharge Elimination System General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing ("Proposed SPDES General Permit").

The proposed regulatory package is deficient in a number of respects. The deficiencies can be divided into three general categories, as follows:

(1) The proposed permitting process is inefficient.

(2) The proposed operating requirements are overly restrictive.

(3) The proposed regulations and permit conditions are unlawful in certain respects.

Overall, the regulatory requirements proposed by DEC threaten to stifle the development of the state's ample natural gas resources. Three primary defects should be remedied prior to finalization of the rdSGEIS, the Proposed HVHF Regulations, and the Proposed SPDES General Permit: (1) the permitting process should be made more efficient; (2) unnecessarily onerous operating requirements should be tempered or eliminated; and (3) legally insufficient requirements should be eliminated. These changes can be accomplished without sacrificing environmental protection, and should be embraced by DEC in order to create a workable operating environment.

The primary deficiencies in the proposed regulatory package are summarized immediately below. Detailed comments follow.

The Proposed Permitting Process Is Inefficient

Duplicity – The Proposed HVHF Regulations include both Mineral Resources regulations (6 NYCRR Parts 550-556 and 560) and SPDES regulations (6 NYCRR Part 750). In promulgating both Mineral Resources regulations and SPDES regulations, DEC has created needless and irrational duplication in the permitting process. The areas of overlap are detailed in Table 1.1 and Appendix A. DEC should eliminate the duplicative language from the SPDES regulations, or eliminate the new HVHF-specific SPDES regulations altogether.

Multiple Agency Involvement – The proposed regulations would have operators interacting with many different government bodies rather than a single authority, creating inefficiency and potential duplication of effort. Table 1.2 and Appendix B identify the multiple agencies involved and their respective roles in the approval process. DEC should make the HVHF operation approval process more efficient by choosing a single permitting authority.

Unconsolidated Permit Conditions – As currently proposed, permit conditions would be derived from multiple regulatory sources: (1) the Proposed Mineral Resources Regulations; (2) the Proposed SPDES regulations and General Permit; (3) the Supplementary Permit Conditions set forth at Appendix 10 of the rdSGEIS; and (4) the Environmental Assessment Form ("EAF") for Well Permitting and the Proposed EAF Addendum set forth at Appendices 5 and 6 of the rdSGEIS. All HVHF operations would be required to comply with the oftentimes overlapping requirements found in each of these sources, a system that would lack a rational basis and cause unnecessary duplication and confusion. DEC should include *all* permit conditions in a *single* set of duly promulgated regulations – the Mineral Resources regulations – and require a single Drilling Permit which includes all applicable requirements.

Excessive Planning Requirements – Under the proposed regulatory package, there is a seemingly limitless array of pre-approval plans that must be satisfied, some of which would be better implemented as regulatory operational requirements and others of which appear to be entirely arbitrary. One such ill-advised planning requirement is the minimum of three-year plant and animal survey required for potentially building surface locations in Focus Areas, many of which occur in counties that have existing resource development. Table 1.4 lists the pre-permitting demonstrations required by the proposed regulations and the rdSGEIS.

Local Government Involvement – In a manner inconsistent with the statutory preemption provision at New York's Environmental Conservation Law ("ECL") 23-0303(2), the rdSGEIS would grant local zoning authorities the power to force additional site-specific review, with no timeline for completion of such review. DEC would be better served by recognizing, and implementing with fidelity, the preemptive effect of ECL 23-0303(2), and not seeking to become a zoning enforcement agency.

The Proposed Operating Requirements Are Overly Restrictive

Onerous Setbacks and Prohibitions – The proposed regulations would, without a rational basis, include onerous setbacks and prohibitions that would diminish the ability of natural gas producers to develop large portions of New York's natural gas resources, while simultaneously causing unintended environmental impacts resulting from the development of additional pad sites. DEC should reduce or eliminate the restrictions as necessary to make New York's siting requirements more in line with the other gas producing states in the region. Furthermore, DEC should include provisions to allow setbacks to be waived by DEC as appropriate.

Requirement to Develop Pads in Phases & Unnecessary Preclusion on Production – DEC has proposed three phases of regulation under an SPDES Permit, corresponding to three phases of development at a well pad: (1) the Construction Phase; (2) the HVHF Phase; and (3) the Production Phase. Because of the strict divisions between phases, the regulations appear to preclude production from any well at a multi-well pad until all wells are completed. This restriction on production would represent a substantial and arbitrary constraint on the ability to deliver gas to market in a timely manner.

Impractical Time Limits on Drilling – As proposed, all horizontal wells at a common well pad must be drilled within three years, and only four wells may be drilled or completed during any consecutive 12-month period at a single well pad. Thus, at most, 12 wells may be drilled at a single well pad over its lifetime, but all must be drilled within three years. These time constraints are unrealistic and should be eliminated, particularly in view of the administrative review process DEC proposes.

Water Withdrawal Limitations – Water withdrawal passby flow limitations based on the Natural Flow Regime Method (NFRM) are duplicative of or inconsistent with River Basin Commission standards. DEC should instead defer to the standards implemented by the appropriate River Basin Commissions.

Unlimited Bonding – The regulatory proposal would eliminate existing limitations on the amount of financial assurance required for wells and not replace them. This would result in potentially unlimited bonding requirements, subject to the discretion of DEC, and without any aggregate cap regardless of the number of wells drilled by an operator. This proposal would arbitrarily require many operators to post financial assurance in amounts that materially exceed any reasonable calculation of risk to the state. DEC should leave the existing financial assurance limits in place.

Incident Reporting Required for Inconsequential Events – The proposed regulations would require operators to report to DEC any "non-routine incident" at a well pad. Given the description of "non-routine incident" contained in the proposed regulations, the potential breadth of this requirement seems excessive and arbitrary. DEC should clarify the proposed regulations to confirm that incident reporting is required only in the event of releases into the environment that pose a risk of significant harm or circumstances presenting a significant risk to public safety.

Excessive Shut-down Authority – The rdSGEIS and proposed regulations purport to provide DEC with the authority to require immediate cessation of operations if it receives a water supply complaint that coincides with certain non-routine well pad incidents. Cessation of operations simply because a third-party complaint coincides with a "non-routine incident" would be excessive and arbitrary. The proposed regulations and rdSGEIS should clarify that cessation of operations would depend upon an established connection between the complaint and the incident, as well as a risk of substantial harm from continued operation.

Excessive Testing of Produced Water – Testing for naturally occurring radioactive materials ("NORM") would be required for all water produced from flowback operations "prior to removal from the site." This is an inefficient and irrational approach that, if adopted, would create substantial delay in the management of fluids. It also fails to recognize that many such fluids are destined for off-site reuse, rather than disposal. A representative sampling approach would be much more practical and promote efficiency in the proper handling of fluids.

Inflexible Best Management Practices – Best Management Practices ("BMPs") are stated as mandatory control measures. This approach is inconsistent with the typical usage of BMPs as recommended measures and would foreclose use of more efficient or protective alternative measures. The proposed regulations and related requirements should be revised to utilize BMPs in their intended form as recommended measures to be utilized where appropriate, not as mandatory, inflexible requirements.

Air Emissions Requirements Inconsistent with Federal Standards – The rdSGEIS proposes state air emissions requirements that diverge from the Clean Air Act ("CAA"), including recently proposed standards that apply to the oil and natural gas sector. In all areas of overlap, DEC should rely on federal rules instead of issuing its own.

The Proposed Regulations and Permit Conditions Are Unlawful in Certain Respects

Stormwater Discharge Permits Are Not Authorized – DEC lacks authority, under either state or federal law, to require oil and gas operators to obtain a SPDES stormwater permit for uncontaminated discharges. DEC should not require HVHF operations to obtain a stormwater permit for such discharges.

Regulatory Takings – The outright ban on HVHF operations on state-owned lands constitutes a regulatory taking without compensation. The setbacks and prohibitions also would constitute a taking as applied to some operators or situations. DEC should reduce or eliminate these setbacks and prohibitions.

Failure to Recognize Existing Preemption of Local Zoning Laws – ECL 23-0303(2) expressly preempts local zoning laws to the extent that they regulate the natural gas industry. The rdSGEIS ignores the preemptive effect of the ECL and purports to provide local zoning authorities with the power to force site-specific review of HVHF projects. DEC should not give effect to preempted local laws.

Single Source Determinations – In Appendix 18 of the rdSGEIS, DEC has stated that it will consider the "interdependence" of natural gas facilities to determine whether they are "adjacent" and thus constitute a single source for the purposes of CAA regulation. DEC should instead look to the plain language of the CAA and its implementing regulations and reject any consideration of "interdependence."

DETAILED COMMENTS

1. The Proposed Permitting Process Is Inefficient

New York's ECL imposes a statutory duty on DEC to (1) foster, promote, and encourage the development, production, and utilization of the natural resources of oil and gas in such a manner as will prevent waste, and (2) spur the development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had. ECL 23-0301. Similarly, New York's Energy Law proclaims that the state should foster, encourage and promote the prudent development and wise use of all indigenous state energy resources, including on-shore oil and natural gas and natural gas from Devonian shale formations. Energy Law § 3-101(5). With the proposed regulatory package for HVHF operations, however, DEC has failed to pursue its statutorily-defined mission. Not only are the substantive operating requirements imposed on HVHF operations onerous (as discussed below in Part 2), but the permitting process itself is needlessly inefficient and, therefore, arbitrary and unreasonable.

The following discussion examines the key aspects of the project approval process that, if adopted, will decrease permitting efficiency with virtually no corresponding environmental benefit. These include (1) duplicative permitting requirements; (2) multiple agency review; (3) failure to consolidate permit requirements in one place; (4) sheer magnitude of plans; and (5) the unnecessary role of local governments.

1.1 Needless Duplicity Is Created by Promulgating Two Sets of Regulations and Requiring Two Separate Permits

The Proposed HVHF Regulations include both Mineral Resources regulations (6 NYCRR Parts 550-556 and 560) and SPDES regulations (6 NYCRR Part 750). In proposing to promulgate both Mineral Resources regulations and SPDES regulations, DEC has created needless and irrational duplicity in the permitting process for HVHF operations. With regard to numerous aspects of HVHF operations, DEC has proposed identical requirements which must be satisfied twice – once in the context of an application for a Permit to Drill, Deepen, Plug Back or Convert Wells ("Drilling Permit") pursuant to the Mineral Resources regulations, and then again in the context of an application for an SPDES stormwater permit (either individual or general) – as well as similar but not quite identical requirements under both programs that each must be satisfied, causing confusion as to what constitutes compliance with DEC requirements.

By way of example, both the proposed Mineral Resources regulations at 6 NYCRR § 560.5 (Testing, Recordkeeping and Reporting Requirements) and the proposed SPDES regulations at 6 NYCRR § 750-3.13 (Monitoring requirements in HVHF SPDES permits) contain requirements for water well testing. Proposed 6 NYCRR § 560.5(d) would require:

> (1) prior to well spud, the operator must make all reasonable attempts to sample and test residential water wells within 1,000 feet of the well pad for the parameters specified by the department. If no wells are available for sampling within 1,000 feet of the well pad, either because there are none of record or because any property owners within 1,000 feet of the well pad deny the operator permission to sample their wells, then the

operator must make all reasonable attempts to sample and test water wells within 2,000 feet for the parameters specified by the department. The owner of any water well tested must be provided with a copy of the test results within 30 days of the operator's receipt of the results.

> (2) water well test results and documentation of efforts to provide such results to the owner(s) of residential water wells must be maintained by the operator and made available to the department upon request.
>
> (3) the operator must sample and test residential water wells in the same manner as provided in paragraph (1) of subdivision (d) of this section, at other intervals specified by the department after the well reaches total measured depth specified on an application for permit to drill.
>
> (4) copies of test results and documentation related to delivery of test results to owners of water wells must be made available to the department and local health department, upon department request, and such records must be maintained for a period up to and including five years after the well, subject to Part 552 of this Title, is permanently plugged and abandoned pursuant to a plugging permit issued by the department. For multi-well pads, the five-year term specified in this paragraph shall begin after the last well subject to Part 552 of this Title is permanently plugged and abandoned pursuant to a plugging permit issued by the department.

The SPDES regulations, meanwhile, contain similar but differently constructed requirements at proposed § 750-3.13:

> (h) Prior to site disturbance (for a new well pad) or spud (for an existing pad), the well operator must sample and test all residential water wells within 1,000 feet of the well pad for which the water well owner has granted permission, and provide results to the water well owner. If no water wells are available for sampling within 1,000 feet, either because there are none of record or because the water well owner denies permission, then all residential water wells within 2,000 feet of the well pad for which the water well owner has granted permission must be sampled and tested. Ongoing water well monitoring and testing must continue at other intervals specified by the Department.
>
> (i) Water well analysis must be by an ELAP-certified laboratory. Analyses and documentation that all test results were provided to the water well owner must be maintained by the operator and made available to the Department upon request.

As another example, both sets of regulations contain testing requirements for produced water from flowback operations. Proposed 6 NYCRR § 560.7(f) would require:

> Flowback water recovered after high-volume hydraulic fracturing operations must be tested for naturally occurring radioactive material prior

to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for naturally occurring radioactive material prior to removal, and the ground adjacent to the tanks must be measured for radioactivity, in accordance with a department-prescribed schedule.

A nearly identical requirement is found at proposed 6 NYCRR § 750-3.11(i):

> . . . . 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, and the ground adjacent to the tanks must be measured for radioactivity. All testing must be in accordance with protocols satisfactory to the New York State Department of Health.

Table 1.1 identifies the areas where these overlaps between the two regulatory programs occur. An expanded version of the table with substantive descriptions of the overlapping requirements is included as Appendix A.

Table 1.1 – Duplicative Regulations

Topic or Requirement	Drilling Permit Requirement	SPDES Permit Requirement
Setbacks	§ 560.4(a)	§ 750-3.3(b)
Chemical Disclosure	§ 560.3(c)	§ 750-3.1.1(e)(1)(ii); §§ 750-3.12(b)(4) – (6); § 750-3.13(e)
Water Well Testing	§ 560.5(d)	§§ 750-3.13(h) & (i)
Closed-Loop Tank System Requirement	§ 560.6(c)(7);	§ 750-3.4(b)(2); § 750-3.11(h)
Prohibition of Waste Fluid Storage in a Pit or Impoundment	§ 560.6(c)(27); § 560.7(g)	§ 750-3.4(b)(3); § 750-3.11(i)
Testing Requirements Related to Waste Fluids	§ 560.7(f)	§ 750-3.11(i).
45 Day Removal Requirement For Waste Fluids	§ 560.7(a)	§ 750-3.4(b)(5)
Requirement to Develop a Fluid Disposal Plan	§ 554.1(c)(1)	§ 750-3.12(b)
Pit Requirements	§ 560.6(a)(4)	§ 750-3.4(b)(4)
Secondary Containment	§ 560.6(c)(26)(i)	§ 750-3.11(e)(1)(v)
Record Keeping – Waste Fluids	§§ 560.5(f) & (g)	§ 750-3.13(f) & (g)
Record Keeping – Miscellaneous	§ 560.6(c)(26)(viii)	§§ 750-3.13(b) - (e)
Definitions	§ 560.2	§ 750-3.2

In each case, DEC should eliminate the duplicative language from the proposed SPDES regulations. Any remaining substantive requirements that could fit within the scope of the Mineral Resources regulations should be transferred accordingly. In this manner, DEC could eliminate the HVHF-specific SPDES regulations altogether, and thereby also nullify concerns about the legality of the proposed SPDES stormwater permit requirement as well. *See infra* Part 3.1.

Further complicating matters, the proposed regulations contemplate that HVHF operations will need to obtain the two permits (a Drilling Permit and a SPDES stormwater permit) sequentially rather than simultaneously. This can be inferred from the requirement that an SPDES stormwater permittee provide to DEC an American Petroleum Institute ("API") well permit number as part of its permit application. *See* 6 NYCRR § 750-3.6(b)(3). This API number is not issued until a Drilling Permit has been approved. A sequential permit application process would, without a rational basis, substantially delay issuance of all necessary authorizations to allow a project to proceed. Eliminating the duplicative requirements of an SPDES permit, as suggested above, would avoid this unnecessary delay.

1.2 Multiple Agency Involvement

The proposed regulations would have permit applicants interacting with multiple state agencies, and many different divisions within DEC itself, rather than a single permitting authority. This would introduce further inefficiency into the permitting process.

Specifically, approvals would be required from the DEC Divisions of (1) Water, (2) Mineral Resources, (3) Fish, Wildlife and Marine Resources, (4) Air Resources, (5) Solid Waste Management, and (6) Environmental Permits, as well as (6) the NYS Department of Health and (7) local municipalities across the state. Table 1.2 details the nature of these approvals. Additionally, in Appendix B, we have reproduced Table 8.1 from the rdSGEIS, which identifies the roles contemplated for the many regulatory jurisdictions associated with HVHF operations. The direct involvement of multiple state agencies – and multiple divisions of DEC – is unreasonable and inefficient.

Table 1.2– Multiple Agency/Division Involvement

A Survey of Permits Required from Different Jurisdictions by Primary Agency	
DEC Division of Water	Surface water withdrawals (NFRM)
	SPDES permits
	Water disposal facility (POTW)
	Water supply impoundment will now be regulated as a dam and requires appropriate permit
DEC Division of Mineral Resources	Drilling and completion permits
	Flaring
DEC Division of Fish, Wildlife and Marine Resources	Invasive species control plans

DEC Division of Air Resources	Air emissions mitigation permit conditions
DEC Division of Solid Waste Management	New York State Part 364 waste transporter permit for all wastes with a waste tracking program similar to that used for medical waste
DEC Division of Environmental Permits	Wetlands permitting
Local Jurisdictions	Groundwater wells
	Road use
	Private water well complaints
NYS Department of Health	NORM protocol

Furthermore, the regulatory proposal does not establish time frames within which the several permitting authorities must make decisions on permit applications. The indefinite permitting process proposed by the regulatory package would create unwarranted uncertainty for applicants.

1.3 Unconsolidated Permit Conditions from Multiple Sources

As currently composed, permit conditions would be derived from multiple regulatory sources: (1) the proposed Mineral Resources regulations found at 6 NYCRR Parts 550-556 and 560; (2) the proposed SPDES regulations found at 6 NYCRR Part 750 and the proposed SPDES General Permit; (3) the Supplementary Permit Conditions for HVHF ("Supplementary Permit Conditions"), which capture the mitigation measures identified as necessary by the rdSGEIS, set forth at Appendix 10 of the rdSGEIS; and (4) the EAF for Well Permitting and the Proposed EAF addendum, which appear at Appendices 5 and 6 of the rdSGEIS. All HVHF operations would need to comply with the oftentimes overlapping requirements found in each of these sources, a system that would lack a rational basis.

The Supplementary Permit Conditions, which capture the mitigation measures identified in the rdSGEIS, would be attached to Drilling Permits, and according to DEC, would be enforceable pursuant to ECL Article 71. *See* rdSGEIS § 3.3, at 3-17. DEC has stated that "some or all" of the Supplementary Permit Conditions may be promulgated in revised regulations at some point in the future. *See* rdSGEIS § 8.3.1, at 8-48. At this point, however, only some of the mitigation measures are captured by the currently proposed regulations. *See* rdSGEIS § 3.3, at-17. This decision to transfer only some but not all of the proposed rdSGEIS mitigation measures into the regulations is arbitrary, creates needless confusion about what is required, and opens the door to questions about the respective weight of authority carried by conditions derived from different sources.

Moreover, additional pre-approval requirements are set forth in the EAF and the EAF Addendum. All hydraulic fracturing operations that exceed the 300,000-gallon HVHF threshold would be required to complete the EAF addendum in order to satisfy SEQRA without a site-specific determination. *See* rdSGEIS § 3.2.2.1, at 3-6. Once again, there is considerable but not complete overlap between the EAF Addendum and the regulations, and also with the Supplementary Permit Conditions.

A much better system would be to include *all* permit conditions in a *single* set of duly promulgated regulations – the Mineral Resources regulations – and require a single Drilling Permit which includes all applicable requirements.

At Appendix C, we have included a flow chart that identifies (to the extent discernable) how the various permitting requirements would be implemented in the convoluted HVHF operations approval process, as currently constituted. This flow chart is a first step toward defining how the permitting process would function in practice, a consideration to which DEC has given insufficient attention. Before finalizing the proposed regulatory package, DEC should consider how it can clarify, simplify, and make more efficient the HVHF approval process and revise its proposals accordingly.

1.4 Magnitude and Quantity of Planning Requirements

Under the proposed regulatory package, there is a seemingly limitless array of pre-approval plans that a permittee must satisfy before it can conduct its business. Table 1.4 lists the pre-permitting demonstrations required by the proposed regulations and the rdSGEIS. Many of these plans would be more efficiently implemented simply as operational requirements in the regulations; others are arbitrary and could be eliminated altogether.

Table 1.4- Plans

Plans Required by Proposed Regulations Prior to Permit Issuance
Stormwater Pollution Prevention Plan for site construction (SPDES), see 750-3.2 (b) (13).
Comprehensive Stormwater Pollution Prevention Plan, which includes both a Construction SWPPP and HVHF SWPPP. § 750-3.6(a).
Transportation Plan, § 560.3(a)(20)
Fluid Disposal Plan – primary and contingent, § 554.1(c)(1); § 750-3.12(b).
Cuttings Disposal Plan. § 554.1(c)(4).
Spill Prevention Control and Countermeasure Plan (SPCC), §750-3.11(g).
HVHF Operation Fluid Chemical Additives study, see § 750-3.11(e)(1)(i).
Invasive Species Mitigation Plan. § 560.3(a)(17); § 560.3(b)(3); rdSGEIS 3-13.
NORM testing and handling plan for flowback and equipment. § 750-3.11 (i).
Emergency Response Plan. § 560.5(a).
Acid Rock Drainage Mitigation Plan for cuttings buried onsite, § 560.6(c)(7)(i).
Air Quality Monitoring Plan. rdSGEIS 6-180. *See also* § 560.3(a)(13).
Water Well Monitoring Programs by ELAP-certified laboratory. § 750-3.13(h) & (i).
Water source withdrawal plan, frac and re-frac, see 2011 DSGEIS 3-9 and 8-49.
Inspection and Maintenance Plan for impoundments. rdSGEIS 8-40
Greenhouse Gas Emissions Plan. rdSGEIS 7-116, 11-9.
Dust Control Plan. rdSGEIS 6-116
Endangered or Threatened Species Mitigation plan. rdSGEIS 7-99.
Noise Impacts Mitigation Plan. rdSGEIS 7-134, 11-9.
Visual Impacts Mitigation Plan. rdSGEIS 11-9.
Forest Focus Area Study Plan. rdSGEIS 7-87.
Grassland Focus Area Study Plan. rdSGEIS 7-87.

Environmental Management and Construction Plan for pipelines. rdSGEIS 8-15.
If triggered by any permit other than drilling, an environmental justice screening will be required and, if a potential environmental justice area is identified by the preliminary screening, additional community outreach activities would be required. rdSGEIS 6-263.
Proposed regulations are cited by part; rdSGEIS are cited by page number.

One particularly ill-conceived pre-permitting exercise is the requirement to conduct a Green Frac Fluid Analysis when applying for a SDPDES stormwater permit. *See* Proposed 6 NYCRR § 750-3.11(e)(1)(i). This analysis, which mandates that an operator "develop and evaluate alternatives" to its fluid mixture, must be conducted *each time* that a permittee applies for a HVHF SPDES permit. Repeating the analysis for each application is a needless exercise that would provide no meaningful environmental protection and is therefore arbitrary and irrational. Any requirement to develop and evaluate alternatives should apply only to the first application for a well utilizing a fluid mixture, and then accepted for all subsequent applications in the absence of a material change to the fluid mixture.

Another example among others, is the transportation plan that is contemplated by proposed 6 NYCRR § 560.3(a)(20). In this plan, an operator would need to "indicat[e] the planned route for delivery of raw materials and chemical additives to the [well] site, the proposed route for transport of waste materials and an estimated number of truck trips associated with same." Proposed 6 NYCRR § 560.3(a)(20). It is unclear how DEC expects this requirement to serve any material environmental purpose. It is difficult, moreover, to predict the routes that will be traveled to and from a well site because they often vary depending on a number of unforeseeable factors, including the particular locations of origin and ultimate destination of available trucks and day-to-day traffic patterns. The number of "truck trips," similarly, can vary based on the hauling capacity of available trucks and the particular conditions that happen to arise at the well site. The proposed requirement for a transportation plan is unreasonable and should be eliminated.

The proposed plan requirements that are not eliminated, moreover, should be implemented as operational standards that come into play after permitting but prior to the commencement of operations.

1.5 Local Government Involvement

The rdSGEIS contemplates a role for local land use laws in the permitting process, despite DEC's acknowledgement that ECL 23-0303(2) "supersedes all local laws relating to the regulation of oil and gas development except for local government jurisdiction over local roads or the right to collect real property taxes." rdSGEIS § 8.1.1, at 8-1. Under the rdSGEIS proposal, as implemented by the EAF addendum, permittees would be required to "identify whether the proposed location of the well pad ... conflicts with local land use laws or regulations, plans or Policies." rdSGEIS § 8.1.1.5, at 8-4. If such a conflict exists, DEC "would, at the time of permit application, request additional information so that it can consider whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts." rdSGEIS § 8.1.1.5, at 8-5. Thus, local zoning law "conflicts" would force additional site-specific environmental assessment, with no clear standard or timeline for such review. This would introduce great uncertainty into the permitting process – any "conflict" with local law could cause indefinite delay – and place DEC in a position of enforcing local zoning "conflicts."

Moreover, this proposal fails to recognize the scope of preemption provided by ECL 23-0303(2), *see* Part 3.3, and thereby unjustifiably defers to preempted ordinances. Simply put, if an ordinance has been preempted, it cannot serve as the source of a "conflict," because such a law is null and void and ceases to legally exist. *See Matter of Ames v. Smoot*, 98 A.D.2d 216, 222, (N.Y. App. Div. 1983), *appeal dismissed*, 62 N.Y.2d 804 (1984) ("Since [the local law] infringed on an area of regulation which was exclusive to the State, it was void from its inception. . . . The repeal did not constitute an action 'which may have a significant effect on the environment' [citation omitted] for all it did was correct the village records to expunge an unenforceable and void law."). Indeed, "[w]here the State has demonstrated its intent to preempt an entire field and preclude any further local regulation, local law regulating the same subject matter is considered inconsistent and *will not be given effect*." *Incorporated Village of Nyack v. Daytop Village, Inc.*, 583 N.E.2d 928, 930 (N.Y. 1991) (emphasis added); *see also Jancyn Mfg. Corp. v. County of Suffolk*, 71 N.Y.2d 91, 97 (N.Y. 1987) ("Such [local] laws, were they permitted to operate in a field preempted by State law, would tend to inhibit the operation of the State's general law and thereby thwart the operation of the State's overriding policy concerns."). Rather than seeking to extend its review to purported "conflicts" with local law, DEC should implement with fidelity the preemptive effect of ECL 23-0303(2). DEC is neither well suited nor authorized to be a zoning enforcement agency.

2. The Proposed Operational Requirements Are Overly Restrictive

In addition to the process-oriented deficiencies identified above, the substantive operational requirements that would be imposed by the proposed regulations, rdSGEIS, and HVHF general permit are often overly restrictive. The proposed standards unnecessarily or excessively limit (1) locations where wells may be drilled, (2) the sequence and timing of drilling, and (3) a variety of activities relating to the process of drilling and completing wells.

2.1 Setbacks and Prohibitions

The proposed regulations would, without a rational basis, include restrictive setback requirements that would diminish the ability of natural gas producers to develop New York's natural gas resources, while simultaneously spurring environmental harm. The proposed setbacks are described in proposed 6 NYCRR §§ 560.4(a) and 750-3.3(b). *See also* rdSGEIS § 3.2.4, at 3-14-15. These provisions would prohibit HVHF well pad development in the following areas (all measurements are taken from the closest edge of the well pad):

- Within 500 feet of a private water well (unless this restriction is waived by the water well owner)
- Within 4,000 feet of, and including, any unfiltered surface water supply watershed
- Within 500 feet of, and including, any "primary aquifer"

- Within any 100-year floodplain
- Within 2,000 feet of any public water supply

These restrictions are unusually stringent when compared, for example, to their Pennsylvania counterparts. *See* the Oil and Gas Act of Dec. 19, 1984 (P.L. 1140, No. 223), 58 P.S. §§ 601.205(a) & (b). Table 2.1 compares the New York and Pennsylvania setback requirements.

Table 2.1- Comparison of Setbacks

Protected Resource	New York (Proposed) Setback	Pennsylvania Setback
Any private water well	500 feet (unless waived by owner). § 560.4(a)(1).	200 feet from any water well (unless a variance is granted by PaDEP). 58 P.S. § 601.205(a)
Any unfiltered surface water supply watershed	4,000 feet. § 750-3.3(b)(1).	No corresponding setback
Any primary aquifer	500 feet. § 560.4(a)(2), § 750-3.3(b)(2).	No corresponding setback
Any public water supply	2,000 feet. § 560.4(a)(4), § 750-3.3(b)(4).	200 feet from any water well (unless a variance is granted by PaDEP). 58 P.S. § 601.205(a)
Any stream, river, pond and other bodies of water	Development precluded in the floodplain. § 560.4(a)(3), § 750-3.3(b)(3).	100 feet (unless waived by PaDEP). 58 P.S. § 601.205(b).

In practice, the setback requirements could preclude a given operator from developing a significant portion of its gas acreage in New York, generally, or in a particular region of the state. IOGA NY estimates that approximately 50% of the gas lease acreage in the state, possibly less, would be available for purposes of developing Marcellus shale resources.

Contrary to the statutory goals of preventing waste and maximizing recovery of gas, the proposed prohibitions and setbacks would make it difficult, if not impossible, for an operator to lay out its spacing units in an efficient, orderly, and cost-effective manner. While operators may be able to work around the restrictions to some degree, such as by developing smaller units, doing so would increase the total number of well pads. This would increase environmental impact. And, in any case, the prohibitions and setbacks would render large quantities of gas inaccessible.

In addition, the rdSGEIS would not apply in the following situations – and, instead, any HVHF well development in these areas would require site-specific environmental review:

> 1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along a part of the proposed length of the wellbore;

2) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along the entire proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply;

3) Any proposed well pad within the boundaries of a "principal aquifer," or outside but within 500 feet of the boundaries of a principal aquifer;

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.

rdSGEIS § 3.2.5, at 3-15-16. Site-specific SEQRA assessment would be required in these circumstances because either (1) they are beyond the scope of the analyses of the rdSGEIS or (2) DEC determined that proposed activities in these areas raise environmental issues necessitating a site-specific review. rdSGEIS Executive Summary, at 5. The requirement to undergo a site-specific review likely would operate as a de-facto prohibition because of the potential intensity of the assessment required.

Finally, HVHF surface operations would be prohibited on state-owned lands altogether. 6 NYCRR §§ 52.3 and 190.8(ag). *See* Part 3.2.1 for further discussion. There is no rational basis for differentiating between private and public lands in this context, as both are equally susceptible to resource development and environmental impacts. Therefore, this outright ban should be lifted.

All told, the siting restrictions that would be imposed by the proposed New York regulations likely make the development of gas logistically and economically untenable. DEC should address this situation by reducing the distances involved with some restrictions and eliminating others (such as the total ban on HVHF operations on state lands) altogether, to make New York's siting requirements more in line with the other gas producing states in the region. Furthermore, DEC should include provisions to allow setbacks to be waived by DEC for good cause shown.

2.2 Sequence and Timing of Drilling

2.2.1 <u>Requirement to Develop Pads in Phases</u>

DEC has proposed three phases of regulation under an SPDES Permit, corresponding to three phases of development at a well pad: (1) the Construction Phase; (2) the HVHF Phase; and (3) the Production Phase. *See* Proposed 6 NYCRR §§ 750-3.6(c)-(e); HVHF Fact Sheet at 2. Under the proposed rule:

(c) An owner or operator shall not commence the Construction Phase until its authorization to discharge under the HVHF SPDES permit is effective.

(d) An owner or operator cannot begin the HVHF Phase until a certification is submitted to the Department providing notification that the Construction Phase is complete.

(e) An owner or operator cannot begin the Production Phase until a certification is submitted to the Department providing notification that the HVHF Phase is complete.

As applied to a well pad (rather than individual wells), as the proposed regulation suggests, these provisions appear to preclude production from any well until all wells on a pad are completed. This restriction should be clarified or eliminated as arbitrary, so that each well may be put into production as soon as it is ready to produce, without regard to other drilling that may occur on the pad.

Additionally, to the extent that any limitation on the sequencing of drilling and production remains, such limitation should be correlated with the temporal restrictions on the number of wells to be drilled or completed in any 12-month period (see Part 2.2.2 below). As presently proposed, the sequencing and timing restrictions appear at odds, effectively limiting the ability of operators to maximize the number of wells put into production in a timely way.

2.2.2 Temporal Restrictions on Drilling

The rdSGEIS proposes, as a way of minimizing air emissions, a limit of four wells to be drilled or completed during any consecutive 12-month period at a single well pad. rdSGEIS 7.5.3.1, at 7-108. Taken together with the regulatory requirement that all wells must be drilled within three years of the date the first well in the unit commences drilling, at most, 12 wells could be drilled at a single well pad over its lifetime.

These time limitations have the potential to reduce the productive capacity of some drilling sites and cause needless environmental impacts. Once an operator has developed a well pad site, it makes sense to utilize that site fully rather than initiating operations at another location where new surface impacts would occur.

2.3 Other Onerous Operational Requirements

In addition to unnecessary or excessive limitations on location of wells and the sequence and timing of drilling, the proposed regulations contain significant limitations on various aspects of the drilling and completion process that are not rationally justified or scientifically explained:

(a) *Water withdrawal passby flow limitations are duplicative of and inconsistent with River Basin Commission standards* – DEC plans to enforce water withdrawal passby flow limitations based on NFRM through permit conditions. rdSGEIS § 7.1.1.1 at 7-2. These passby flow limitations would be applied even to projects in the Delaware and Susquehanna River basins, where interstate commissions already implement comprehensive water withdrawal regulatory regimes. rdSGEIS §7.1.1.4, at 7-16. Instead, DEC should defer to these commissions within their jurisdictions, and should utilize stream flow protections commensurate with their methods (rather than NFRM). The apparent decision to depart from the River Basin Commission standards and utilize NFRM is not legally or scientifically justified.

(b) *Bonding Limits* – The proposed regulations would eliminate the bonding limits currently present at 6 NYCRR § 551.6 ($250,000 per well or $2,000,000 in the aggregate). Instead, financial assurance will be required for each well "in an amount that, to the satisfaction of the Department, is based upon the anticipated costs of plugging and abandoning it," without any limitation for any individual well or all wells in the aggregate. This proposal would give DEC excessive discretion in determining the amount of financial assurance required for any given well. Moreover, the lack of any cap on the aggregate amount of financial assurance would arbitrarily require many operators to post financial assurance in amounts that materially exceed any reasonable calculation of risk to the state. DEC should leave the existing financial assurance limits in place, or raise them based on a specific, rational justification.

(c) *Reporting of Any 'Non-routine Incident'* – The proposed regulations would require operators to provide to DEC a verbal report within two hours and a written report within 24 hours of any "non-routine incident of potential environmental and/or public safety significance." *See* Proposed 6 NYCRR § 560.5(c); *see also* rdSGEIS § 7.1.4, at 7-48. Any action or condition known or suspected of causing or contributing to the "non-routine incident" would be required to cease immediately upon discovery, and, in the event hydraulic fracturing pumping operations are suspended, affirmative approval by DEC would be required to recommence such operations. Given the description of "non-routine incident" contained in the proposed regulations, the potential breadth of this requirement seems excessive and arbitrary. "Non-routine incidents," for instance, would include any leak in surface equipment, even one into a containment area. Whether such an incident would be "of potential environmental and/or public safety significance" requiring notification to DEC is not clear. The proposed regulation should be clarified to confirm that incident reporting is required only in the event of releases into the environment that pose a risk of significant harm or circumstances presenting a significant risk to public safety.

(d) *Excessive Shut-down Authority* – The rdSGEIS and proposed regulations purport to provide DEC with the authority to require immediate cessation of operations if it receives a water supply complaint that coincides with certain non-routine well pad incidents. *See* rdSGEIS § 7.1.4, at 7-48; Proposed 6 NYCRR §560.5(c). This enforcement option would be in addition to any applicable enforcement measures listed at rdSGEIS § 8.2.3. Cessation of operations simply because a third-party complaint coincides with a "non-routine incident" (see discussion above) would be excessive and arbitrary. The proposed regulations and rdSGEIS should clarify that cessation of operations would depend upon an established connection between the complaint and the incident, as well as a risk of substantial harm from continued operation.

(e) *Testing All Flowback Water for NORM* – The proposed regulations would require all water produced from flowback operations to be tested for NORM "prior to removal from the site." *See* Proposed 6 NYCRR § 560.7(f). Adopting such a requirement would, without a rational basis, create substantial delay in the management of fluids, particularly if receipt of analytical results is required "prior to removal from the site." Testing water produced from every well also seems excessive. A representative sampling approach would be much more practical and promote efficiency in the proper handling of fluids. Finally, the testing requirement should apply only to fluid that is intended to be disposed, not to fluids that are to be reused in hydraulic fracturing operations.

(f) *BMPs as Mandatory Control Measures* – In the proposed regulations, rdSGEIS, and HVHF general permit, DEC would impose BMPs as hard and fast requirements. For instance, the structural and non-structural BMPs contained at Part X of the Proposed SPDES General Permit mandate a wide variety of particular control measures that a permittee must stipulate to as part of their HVHF Stormwater Pollution Prevention Plan ("SWPP"). Proposed SPDES General Permit at 41-67 This approach is inconsistent with the typical usage of BMPs as recommended measures and would foreclose use of more efficient or protective alternative measures. As an example of a particularly unnecessary requirement from Part X of the SPDES General Permit, DEC would mandate that HVHF SWPPP's include and describe measures that prevent or minimize contamination from lumber storage and processing areas; this section of the HVHF SWPPP "must include" certain good housekeeping procedures, would not allow "wet decking," and would require benchmark monitoring – all despite the fact that natural gas operations do not ordinarily engage in the processing of wood. *See* Proposed SPDES General Permit at 60. Furthermore, the General Permit would require excessive benchmark monitoring using a particular analytical method for each pollutant of concern identified in Part X. Aside from the General Permit, the rdSGEIS would mandate particular "control measures" to mitigate air emissions; instead, it should establish "control thresholds" and then allow the air permitting process and proven control technologies to determine the actual control measures applicable to a given set of circumstances. The proposed regulations and related requirements should be revised to utilize BMPs in their intended form as recommended measures to be utilized where appropriate, not as mandatory, inflexible requirements.

(g) *Air Emissions Requirements Inconsistent with Federal Standards* – The rdSGEIS proposes air emissions requirements that diverge from the CAA, including recently proposed standards that apply to the oil and natural gas sector. *See Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*, 76 Fed. Reg. 52738 (August 23, 2011). For example, in addressing nonroad diesel engines that are used at well sites, the rdSGEIS would prohibit the use of "tier 0" drilling and hydraulic fracturing engines. *See* rdSGEIS 7.5.2 & 7.5.3.1. With regard to drilling and completion engines, moreover, certain other tiers could not be used unless they were outfitted with particulate traps or Selective Catalytic Reduction ("SCR") controls, or both. *See id.* at 7.5.3.1. EPA, by contrast, has not imposed these particular restrictions in connection with nonroad diesel engines, opting instead to synthesize new engine standards and fuel control standards to achieve the largest possible emissions reductions. *See, e.g.,* 69 Fed. Reg. 38958, 38958

(June 29, 2004) ("This comprehensive national program regulates nonroad diesel engines and diesel fuel as a system.... We estimate particulate matter reductions of 95 percent, nitrogen oxides reductions of 90 percent, and the virtual elimination of sulfur oxides from nonroad engines meeting the new standards."). By its proposed approach, DEC is attempting to rework the strategy that EPA has determined to be the best and most feasible for reducing emissions from these engines. As another example, while the rdSGEIS would appear to establish one numerical limit on the amount of benzene that could be emitted from any glycol dehydrator at a well pad, *see* rdSGEIS 7.5.3.1, existing and proposed EPA standards contemplate a suite of options for controlling benzene emissions from these dehydrators, which vary depending on the size of the dehydrator and are not all based on numerical limits, *see* 40 C.F.R. § 63.765(b) & (c) (existing standards, which apply to large dehydrators) and 76 Fed. Reg. at 52746 (proposed standards, which would apply to small dehydrators).

Under the CAA, EPA has invested substantial time, study, and analysis into developing existing and proposed standards for significantly reducing emissions from sources at gas well sites in an efficient and realistic manner. DEC is proposing to undermine these efforts by superimposing its own standards that, in many cases, are inconsistent with EPA's vision and call for technologically infeasible measures. In all areas of overlap, therefore, DEC should simply rely on EPA's rules instead of issuing its own.

3. The Proposed Regulations and Permit Conditions Are Unlawful in Certain Respects

A number of aspects of the proposed regulations raise serious legal questions. In particular: (1) DEC is not authorized to require a stormwater permit for uncontaminated discharges from HVHF operations; (2) the preclusion of HVHF operations on state-owned lands would constitute a regulatory taking without compensation, and the expansive setbacks also could effect an unlawful taking in some situations; (3) reliance on local zoning laws would be inconsistent with ECL preemption of local zoning laws, and unlawful; and (4) single source standards would be inconsistent with the CAA.

3.1 DEC May Not Require Oil and Gas Operations to Obtain a SPDES Permit for Stormwater Discharges

As part of the basic regulatory framework proposed by DEC to regulate hydraulic fracturing, DEC would require all HVHF operations to obtain an SPDES permit for their stormwater discharges. *See* Proposed 6 NYCRR § 750-1.1(g); Proposed SPDES General Permit for Stormwater Discharges from High Volume Hydraulic Fracturing Operations Fact Sheet ("HVHF GP Fact Sheet") at 1. To meet this obligation, operators would have the option of obtaining either an individual SPDES permit or coverage under the Proposed SPDES General Permit, which has been developed in tandem with the part 750 regulations. Proposed § 750-3.4(b). It is through the SPDES permit application process that many of the substantive requirements imposed on HVHF operations are implemented. *See* Proposed §§ 705-3.4, 3.6, 3.11, 3.12, 3.13, 3.14, 3.21, 3.25. As noted above at Part 1.1, many of these requirements are duplicative of the requirements imposed in the Drilling Permit application process and should be eliminated for efficiency reasons. Even if these requirements were desirable, however, the method of imposition – through a permit for stormwater discharges – is not legally permissible.

Under the federal Clean Water Act ("CWA"), 33 U.S.C. §§1251 *et seq.*, uncontaminated discharges of stormwater runoff from "oil and gas exploration, production, processing, or treatment operations or transmission facilities" are generally exempt from permitting requirements pursuant to the National Pollutant Discharge Elimination System ("NPDES") program. *See* CWA § 402(l)(2), 33 U.S.C. §§ 1342(l)(2). In 2006, Congress clarified the scope of this exemption by defining "oil and gas exploration, production, processing, or treatment operations or transmission facilities" as "all field activities or operations associated with exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities." *See* CWA § 502(24), 33 U.S.C. §§ 1362(24). This statutory addition served to bring the construction phase of oil and gas operations within the umbrella of the exemption. *See NRDC v. EPA*, 526 F.3d 591, 599 (9th Cir. 2008). EPA has promulgated regulations further clarifying the extent of the oil and gas operation exemption:

> The operator of an existing or new discharge composed entirely of stormwater from an oil or gas exploration, production, processing, or treatment operation, or transmission facility is not required to [obtain a stormwater discharge permit], unless the facility:
>
> (A) Has had a discharge of stormwater resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 CFR 117.21 or 40 CFR 302.6 at anytime since November 16, 1987; or
>
> (B) Has had a discharge of stormwater resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 CFR 110.6 at any time since November 16, 1987; or
>
> (C) Contributes to a violation of a water quality standard.

40 C.F.R. § 122.26(c)(1)(iii). Thus, oil and gas operations are generally exempt from NPDES stormwater discharge permitting requirements, and must only obtain such a permit if they have had a reportable contaminated discharge or contribute to violations of water quality standards.

Section 402(b) of the CWA, 33 U.S.C. § 1342(b), authorizes states to administer the NPDES permitting program within their borders upon demonstrating their ability to issue permits that meet certain minimum requirements. DEC's SPDES program is New York's primacy implementation of the federal NPDES program. *See* ECL 17-0801. EPA regulations clarify that a state's NPDES regime may include "requirements which are more stringent or more extensive than those required under" the federally recommended state program regulations at 40 C.F.R. Part 123. 40 C.F.R. § 123.1(i)(1). Additionally, nothing in the CWA precludes a state from "[o]perating a program with a greater scope of coverage than that required" under Part 123. 40 C.F.R. § 123.1(i)(2).

Importantly, however, "[i]f an approved State program has greater scope of coverage than required by Federal law the additional coverage is not part of the federally approved program." *Id.* "For example, if a state requires permits for discharges into publicly owned treatment works, these permits are not NPDES permits." *Id.* With respect to stormwater discharges from oil and gas operations exempted from the NPDES program, EPA has explained its position that "states may not require permits for these discharges under the NPDES program." 71 Fed. Red. 894, 896 (Jan. 6, 2006).[1] Thus, DEC must have some other statutory authorization, outside the authorization to implement a state program meeting the requirements of the NPDES program, to require stormwater discharge permits for exempted natural gas facilities. To the extent such authority exists, the permits DEC issues would not be part of its primacy implementation of the NPDES program.

However, nothing in the ECL provides DEC with the authority to require exempted oil and gas operations to obtain a stormwater permit through its SPDES program. ECL 17-0303, which governs the general powers and duties of DEC with regard to water pollution control, states that DEC "shall have administrative jurisdiction to abate and prevent the pollution of waters of the state in the manner herein provided in accordance with . . . standards, criteria, limitations, rules and regulations and permit conditions adopted, promulgated or applied by [DEC] *pursuant to title 8* [regarding the SPDES program] hereof." ECL 17-0303(2) (emphasis added). Title 8, at ECL 17-0801, merely declares the purpose "[t]o create a state pollutant discharge elimination system (SPDES) to insure that the State of New York shall possess adequate authority to issue permits regulating the discharge of pollutants from new or existing outlets or point sources into the waters of the state, upon condition that such discharges will conform to and meet all applicable requirements of the [CWA] and rules, regulations, guidelines, criteria, standards and limitations adopted pursuant thereto . . . and to participate in the national pollutant discharge elimination system (NPDES) created by the [CWA]." Thus, it was the explicit desire of the New York legislature that the SPDES program conform to the federal NPDES program. The only manner in which the ECL authorizes DEC to go beyond the scope of the federal program is with respect to discharges to groundwater, through its expansive definition of "waters". *See* ECL 17-0105 (defining "waters" to include "all other bodies of surface *or underground water* . . . which are . . . within or bordering the state") (emphasis added). In fact, in its existing SPDES regulations, DEC already has acknowledged that stormwater discharges to surface waters, like those proposed to be regulated by the proposed HVHF regulations and general permit, shall be permitted in accordance with the federal regulations at 40 C.F.R. § 122.26, which includes the regulation that implements the exemption for uncontaminated stormwater discharges from oil and gas operations. 6 NYCRR § 750-1.4(b) ("For discharges of stormwater that are not to groundwater, permits shall be required in accordance with 40 C.F.R. § 122.26 . . . .").

[1] *See also id.* at 898 ("Discharges that would be exempted from NPDES permit requirements in today's proposal would be exempted from such NPDES requirements regardless of whether EPA or a State is the permitting authority. EPA wishes to clarify, however, that today's proposal is not intended to interfere with the States' ability to regulate any discharges through a State's non-NPDES program. However, if a State were to require a permit for discharges exempt from the Clean Water Act NPDES program requirements, the State's permit requirement would not be considered part of the State's EPA-approved NPDES program.")

In the proposed regulations, DEC has stated that "New York law also authorizes other broad protections for ground and surface waters beyond those authorized by the [CWA]." Proposed 6 NYCCR § 750-1.1(a). In addition, DEC's proposed rules mention that "[t]he regulations in [Part 750] prescribe procedures and substantive rules concerning the SPDES program *as well as non-SPDES water quality protections as set forth in the statutory authority for this Part.*" 6 NYCCR § 750-1.1(b). The statutory authority for Part 750, however, contains no provision that would authorize DEC to require SPDES permits of federally exempted operations. Without any basis in state law, DEC's proposed requirement that HVHF operations obtain a stormwater permit for all stormwater discharges is left unsupported by any statutory authority, state or federal, and would be unlawful.

Thus, adoption of the proposed SPDES regulations would represent an unlawful exercise, and should not be pursued.

3.2 Regulatory Takings

3.2.1 The Ban on HVHF Operations on State-Owned Lands Constitutes an Unlawful Taking

The regulations proposed at 6 NYCRR §§ 52.3 and 190.8(ag) would establish that "surface disturbance associated with the drilling of a natural gas well subject to Part 560 of this Title [dealing with HVHF operations] on State lands is prohibited and no permit shall be issued authorizing such activity." In other words, the proposed regulations would fully prohibit an operator from making reasonable use of the surface estate on state-owned lands for purposes of using hydraulic fracturing to develop the underlying gas even if the operator held a lease that covered the lands.

Persuasive case law from the Pennsylvania Supreme Court suggests that, on its face, this prohibition amounts to a "taking" of private property for public use (under the U.S. or New York Constitution), requiring payment of just compensation to affected operators. In *Belden & Blake Corporation v. Department of Conservation and Natural Resources*, 969 A.2d 528 (Pa. 2009), a state agency owned the surface estate of a property, while a private operator owned the underlying oil and gas. The agency unilaterally imposed several burdensome conditions on the operator's ability to access the surface to develop the oil and gas. The agency claimed that certain provisions in Pennsylvania's Constitution and the Pennsylvania Conservation and Natural Resources Act gave it the authority to impose the conditions. The Pennsylvania Supreme Court disagreed. It began by noting that, at common law, the owner of mineral interests has a vested property right to access the overlying surface area, as reasonably necessary, to extract the minerals. It then explained that "[a] 'regular' surface owner cannot unilaterally impose extra conditions on the subsurface owner beyond those that are reasonable. [The agency] may wish to do so because of its statutory duties, but its mandate does not allow it to do so unilaterally, nor does it shift the burden of seeking redress to the subsurface owner . . . . [T]he government and its agencies must be held to the same standard as any other surface owner." *Id.* at 532-33. The court went on to explain that, if the agency desired to unilaterally impose extra conditions – even for a laudable public purpose – it could do so only by exercising its powers of eminent domain:

> [The agency] may *seek* additional conditions because of its mandate, but it has no authority to *impose* them unilaterally without compensation.
>
> ****
>
> If [the agency] wishes further conditions [i.e., beyond those that are reasonable] pursuant to its statutory duties, the Commonwealth must compensate the subsurface owner for the diminution of its rights; indeed it may condemn the subsurface interests altogether pursuant to the Eminent Domain Code.
>
> However, a property owner's interests and rights cannot be lessened, nor their reasonable exercise impaired without just compensation, simply because a governmental agency with a statutory mandate comes to own the surface.

Id. at 533 (emphasis in original).

New York's common law affords an oil and gas lessee the same right of reasonable surface access as Pennsylvania's. *See, e.g., Marvin v. Brewster Iron Mining Co.*, 55 N.Y. 538 (N.Y. 1874); *see also Drake v. Fox*, 894 N.Y.S.2d 306, 307 (N.Y. App. Div. 2010) ("'[A] mineral estate in a tract of land carries with it the right to such access over the surface that may be reasonably necessary to carry on mining activities.'") (addressing access by oil and gas lessees) (quoting *Allen v. Gouverneur Talc Company, Inc.*, 247 A.D.2d 691, 692 (N.Y. App. Div. 1998)); *see also* N.Y. Gen. Constr. Law 39 (characterizing the lessee's rights as personal property for all purposes except taxation). Therefore, as in *Belden & Blake*, if the state "takes" private property for public use by unilaterally imposing unreasonable conditions on the lessee's ability to access the surface of state-owned lands that are covered by the lease, then New York would effectuate a taking by completely barring the lessee from accessing the surface in connection with hydraulic fracturing – as would occur through proposed 6 NYCRR §§ 52.3 and 190.8(ag). Accordingly, this outright ban on hydraulic fracturing on state owned lands should be reconsidered.

3.3 The ECL Preempts Local Zoning Laws relating to Oil and Gas

As mentioned above in Part 1.5, the rdSGEIS contemplates a role for local land use laws in the permitting process, despite DEC's position that its own "exclusive authority to issue well permits supersedes local government authority relative to well siting." rdSGEIS § 8.1.1.5, at 8-4. Under the rdSGEIS proposal, as implemented by the EAF addendum, permittees would be required to "identify whether the proposed location of the well pad . . . conflicts with local land use laws or regulations, plans or Policies." rdSGEIS § 8.1.1.5, at 8-4. If the applicant identifies a conflict, or if "the potentially impacted local government advises [DEC] that it believes the application is inconsistent with such laws, ... [DEC] would, at the time of permit application, request additional information so that it can consider whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts." rdSGEIS § 8.1.1.5, at 8-5. Thus, local governments would have the power to force additional site-specific environmental review by DEC under the rdSGEIS.

This process is not consistent with New York law, which preempts local regulation of oil and gas. In particular, ECL 23-0303(2) provides:

> The provisions of this article [the Mineral Resources regulations] shall supersede all local laws or ordinances relating to the regulation of the oil, gas and solution mining industries; but shall not supersede local government jurisdiction over local roads or the rights of local governments under the real property tax law.

In light of this provision, any ordinance relating to the regulation of oil and gas in New York has been superseded and, therefore, cannot possibly serve as the basis for a "conflict" with a proposed well, because such laws are null and void. *See supra* at Part 1.5. Any suggestion to the contrary by the rdSGEIS should be eliminated.

3.4 Proposed Single Source Requirements Are Inconsistent With Federal Law

Despite acknowledging that "interdependency" is not "an express element of the actual three-part test set forth in regulation," DEC has declared its intention to consider interdependence in making single source determinations under the federal CAA in the context of the natural gas industry. *See* Appendix 18 of the rdSGEIS. ("Nevertheless, to be thorough, DEC staff will evaluate the nature of the relationship between the facilities and the degree of interdependence between them to determine whether the noncontiguous emissions points should be aggregated.") This would conflict with the plain meaning of the CAA and its implementing regulations, which allow for no consideration of interdependence in single source determinations.

EPA regulations establish a three part test to determine whether multiple emitting activities should be considered a single stationary source for permitting purposes. To constitute a single source, the pollutant emitting activities must be:

(1) In the ***same industrial grouping***, which is the case if they have the same two-digit SIC code;

(2) Located on one or more ***contiguous or adjacent*** properties; and

(3) Under ***common control***.

See 40 C.F.R. § 51.165(a)(1)(ii); 40 C.F.R. § 51.166(b)(6); 40 C.F.R. 51.21(b)(6); 40 C.F.R. § 70.2. Each part of the test must be satisfied in order to be classified as a single source. *See, e.g.*, *In Re Anadarko Petroleum Corp.*, EPA Order Denying Petition for Objection to Permit (Permit No.: 95OPWE035; Petition No.: VIII-2010-4) at 7 (issued Feb. 2, 2011). The preamble to EPA's 1980 PSD regulations, in which the three-part test first appeared, provides additional texture to the source determination analysis. In making determinations using the three three-part test, a permit reviewer should consider that the definition of "source": (1) must carry out reasonably the purposes of the PSD program; (2) is meant to approximate a common sense notion of a "plant," and (3); should not result in the aggregation of pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building," "structure," "facility," or "installation." *See* 45 Fed. Reg. 52676, 52694-95 (Aug. 7, 1980). These interpretive guides grew out of a 1980 decision, *Alabama v. Costle*, in which the D.C. Circuit rejected EPA's prior definition of a "source." *See* 636 F.2d 323 (D.C. Cir. 1980).

Nowhere in the CAA, EPA regulations, or regulatory history is interdependence mentioned as a relevant factor in making single source determinations. In fact, in the 1980 preamble, EPA *explicitly rejected* use of "functional interrelationships" in making single source determinations; instead, EPA chose to use SIC codes as a more administrable proxy for interdependence between facilities:

> In formulating a new definition of "source," EPA accepted the suggestion of one commenter that the Agency use a standard industrial classification code for distinguishing between sets of activities on the basis of their functional interrelationships. While EPA sought to distinguish between activities on that basis, it also sought to maximize the predictability of aggregating activities and to minimize the difficulty of administering the definition. To have merely added function to the proposed definition as another abstract factor would have reduced the predictability of aggregating activities under that definition dramatically, since any assessment of functional interrelationships would be highly subjective. To have merely added function would also have made administration of the definition substantially more difficult, since any attempt to assess those interrelationships would have embroiled the Agency in numerous, fine-grained analyses. A classification code, by contrast, offers objectivity and relative simplicity.

45 Fed. Reg. 52676, 52695 (Aug. 7, 1980). Ignoring the plain command of the law, DEC now plans to consider interdependency in determining whether natural gas facilities are "adjacent" to one another. The plain meaning of the word "adjacent," however, involves merely spatial distance and proximity. For instance, the online edition of the Merriam-Webster dictionary defines "adjacent" as: "not distant;" "nearby;" "having a common endpoint or border." (last visited Jan. 6, 2012). DEC should read the word "adjacent" in accordance with its plain meaning and dictionary definition, and thus not consider interdependence when making single source determinations, just as the Pennsylvania Department of Environmental Protection ("PaDEP") has declared that it will do. *See PaDEP Guidance for Permitting Single Stationary Source Determinations for Oil and Gas Industries*, Doc. No. 270-0810-006, at 6-7 (Oct. 12, 2011).

Appendix A

Duplicative Regulations:

Topic or Requirement	Drilling Permit Requirement	SPDES Permit Requirement
Setbacks	No well pad or portion of a well pad may be located: (1) closer than 500 feet from a private water well unless waived by the water well owner; (2) within a primary aquifer and a 500-foot buffer from the boundary of a primary aquifer; (3) within a 100-year floodplain; and (4) within 2,000 feet of any public water supply (municipal or otherwise) well, reservoir, natural lake or man-made impoundment (except engineered impoundments constructed for fresh water storage associated with fracturing operations), and river or stream intake. § 560.4(a).	HVHF operations on the ground surface are prohibited in the following areas: (1) within 4,000 feet of, and including the, unfiltered surface water supply watersheds; (2) within 500 feet of, and including, a primary aquifer; (3) within 100-year floodplains; and (4) within 2,000 feet of any public (municipal or otherwise) water supply, including wells, reservoirs, natural lakes or man-made impoundments, and river or stream intakes. § 750-3.3(b).
Chemical Disclosure	Hydraulic Fracturing Fluid Disclosure. (1) With each application for a permit to drill, deepen, plug back or convert a well subject to this Part, the owner or operator shall provide the following information: (i) proposed volume of each additive product to be used in hydraulic fracturing (ii) identification of each additive product proposed for use; (iii) copies of Material Safety Data Sheets for each product to be used if the Material Safety Data Sheet is not already on file with the Division; (iv) proposed percent by weight of water, proppants and each additive product; (v) 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; and (vi) the identification of the proposed fracturing service company. (2) The department will disclose to the public the information submitted pursuant to paragraph (1) of this subdivision except that operators or other persons who supply information subject to paragraph (1) of this subdivision may request such records to be	HVHF Chemical Additives Used on Site - The owner or operator must maintain a list of the HVHF additives (volumes/amounts of all chemicals/additives used for each HVHF event). § 750-3.11(e)(1)(ii). All HVHF permit applications must include a Fluid Disposal Plan, subject to Departmental review and approval, for disposal of flowback water and production brine. The Fluid Disposal Plan shall assure compliance with the narrative requirements in 750-3.5(a) over the life of the well, and shall include: . . . (4) identification of all chemical additive products to be used, by product name, purpose, and type, proposed percent by weight of water, proppants and each chemical, and the anticipated volume of each additive product proposed for use; (5) Material Safety Data Sheets (MSDS) for every additive product proposed for use, unless the MSDS for a particular product is already on file with the Department as a result of prior development or was transmitted to the

	exempt from disclosure as provided by Part 616 of this Title. Records determined by the department to be exempt from disclosure shall not be considered a well record for purposes of disclosure. § 560.3(c).	Department during the application process for a previous well permit; and (6) Exact chemical composition of any additional additives which have not yet been proposed for use before the Department. § 750-3.12(b). The HVHF SWPPP must include provisions to maintain a record of the amounts of all chemicals/additives associated with each time there is a high-volume hydraulic fracturing stage during the HVHF Phase. This list may exclude any information that has been determined to be confidential business information. The record shall include a list of the individual chemicals/additives with Chemical Abstract Services (CAS) registry number and Material Safety Data Sheets (MSDS). § 750-3.13(e)
Water Well Testing	Water well testing: (1) prior to well spud, the operator must make all reasonable attempts to sample and test residential water wells within 1,000 feet of the well pad for the parameters specified by the department. If no wells are available for sampling within 1,000 feet of the well pad, either because there are none of record or because any property owners within 1,000 feet of the well pad deny the operator permission to sample their wells, then the operator must make all reasonable attempts to sample and test water wells within 2,000 feet for the parameters specified by the department. The owner of any water well tested must be provided with a copy of the test results within 30 days of the operator's receipt of the results. (2) water well test results and documentation of efforts to provide such results to the owner(s) of residential water wells must be maintained by the operator and made available to the department upon request. (3) the operator must sample and test residential water wells in the same manner as provided in paragraph (1) of subdivision (d) of this section, at other intervals specified by the department after the well reaches total	Prior to site disturbance (for a new well pad) or spud (for an existing pad), the well operator must sample and test all residential water wells within 1,000 feet of the well pad for which the water well owner has granted permission, and provide results to the water well owner. If no water wells are available for sampling within 1,000 feet, either because there are none of record or because the water well owner denies permission, then all residential water wells within 2,000 feet of the well pad for which the water well owner has granted permission must be sampled and tested. Ongoing water well monitoring and testing must continue at other intervals specified by the Department. § 750-3.13(h). Water well analysis must be by an ELAP-certified laboratory. Analyses and documentation that all test results were provided to the water well owner must be maintained by the operator and made available to the Department upon request.

	measured depth specified on an application for permit to drill. (4) copies of test results and documentation related to delivery of test results to owners of water wells must be made available to the department and local health department, upon department request, and such records must be maintained for a period up to and including five years after the well, subject to Part 552 of this Title, is permanently plugged and abandoned pursuant to a plugging permit issued by the department. For multi-well pads, the five-year term specified in this paragraph shall begin after the last well subject to Part 552 of this Title is permanently plugged and abandoned pursuant to a plugging permit issued by the department. § 560.5(d).	§ 750-3.13(i).
Closed-Loop Tank System Requirement	A closed-loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings for any of the following: (i) horizontal drilling in the Marcellus Shale unless an acid rock drainage mitigation plan for on-site burial of such cuttings is approved by the department; and (ii) any drilling requiring cuttings to be disposed of off-site, as provided in Part 360 of this Title, including at a landfill. § 560.6(c)(7).	The owner or operator of an HVHF well shall submit . . . (2) Certification that closed loop drilling will be used or an approvable alternative plan that will ensure there will be no significant adverse water quality impacts related to the disposal of pyrite rich Marcellus Shale cuttings if an on-site pit is approved by the Department; § 750-3.4(b)(2) . A closed-loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings for any of the following: (i) horizontal drilling in the Marcellus Shale unless an acid rock drainage mitigation plan for on-site burial of such cuttings is approved by the Department; and (ii) any drilling requiring cuttings to be disposed of offsite, as provided in Part 360 of this Title, including at a landfill. § 750-3.11(h).
Prohibition of Waste Fluid Storage in a Pit or Impoundment	Flowback water is prohibited from being directed to or stored in any on-site pit. Covered watertight steel tanks or covered watertight tanks constructed of another material approved by the department are required for flowback handling and containment on the well pad. Flowback water tanks, piping and conveyances, including	The owner or operator of an HVHF well shall submit . . . (3) Certification that HVHF flowback fluids will not be directed to or stored in a pit or impoundment; § 750-3.4(b)(3). Flowback water is prohibited from

	valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition. § 560.6(c)(27). Production brine is prohibited from being directed to or stored in any on-site pit. Covered watertight steel, fiberglass or plastic tanks, or covered watertight tanks constructed of another material approved by the department, are required for production brine handling and containment on the well pad. Production brine tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition. § 560.7(g).	being directed to or stored in any pit or impoundment. Covered watertight steel tanks or covered watertight tanks constructed of another material approved by the Department are required for flowback handling and containment on the well pad. Flowback water tanks, piping and conveyances, including valves, must be of sufficient pressure rating and be maintained in a leak-free condition. § 750-3.11(i).
Testing Requirements Related to Waste Fluids	Flowback water recovered after high-volume hydraulic fracturing operations must be tested for naturally occurring radioactive material prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for naturally occurring radioactive material prior to removal, and the ground adjacent to the tanks must be measured for radioactivity, in accordance with a department-prescribed schedule. § 560.7(f).	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, and the ground adjacent to the tanks must be measured for radioactivity. All testing must be in accordance with protocols satisfactory to the New York State Department of Health. § 750-3.11(i).
45 Day Removal Requirement For Waste Fluids	Fluids must be removed from any on-site pit and the pit reclaimed no later than 45 days after completion of drilling and stimulation operations at the last well on the pad, unless the department grants an extension pursuant to paragraph 554.1(c)(3) of this Title. Flowback water must be removed from on site tanks within the same time frame. § 560.7(a).	The owner or operator of an HVHF well shall submit . . . (5) Certification that all waste fluids will be removed from the wellpad and associated storage areas adjacent to the wellpad no more than 45 days after stimulation of each well unless otherwise approved by the Department as part of a recycling plan; § 750-3.4(b)(5).
Requirement to Develop a Fluid Disposal Plan	Prior to the issuance of a permit to drill, deepen, plug back or convert a well for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during such drilling operations or used to conduct such operations in sufficient quantities to be deleterious to the surrounding environment, the operator must submit and receive approval for a plan for the environmentally safe and proper ultimate	All HVHF permit applications must include a Fluid Disposal Plan, subject to Departmental review and approval, for disposal of flowback water and production brine. The Fluid Disposal Plan shall assure compliance with the narrative requirements in 750-3.5(a) over the life of the well, and shall include: (1) a certification by a proper disposal

	disposal of such fluids. Before approving 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 operator, a permit for discharge and/or disposal may be required by the department in addition to the permit to drill, deepen, plug back or convert. An applicant may also be required at the department's discretion to submit an acceptable contingency plan, the use of which shall be required if the primary plan is not approved, unsafe or impracticable at the time of disposal. § 554.1(c)(1).	facility that available capacity exists at that facility for the disposal of the projected amount of flowback and production brine over the life of the well, (2) identification and certification by the HVHF permittee of alternative or contingent disposal location(s) with sufficient capacity to accept the generated wastewater over the life of the well; (3) projected concentrations of chemical constituents of the flowback and production brine over the life of the well, based upon additives used, well sampling, and data from similar wells. (4) identification of all chemical additive products to be used, by product name, purpose, and type, proposed percent by weight of water, proppants and each chemical, and the anticipated volume of each additive product proposed for use; (5) Material Safety Data Sheets (MSDS) for every additive product proposed for use, unless the MSDS for a particular product is already on file with the Department as a result of prior development or was transmitted to the Department during the application process for a previous well permit; and (6) Exact chemical composition of any additional additives which have not yet been proposed for use before the Department. § 750-3.12(b).
Pit Requirements	Any reserve pit, drilling pit or mud pit on the well pad which will be used for more than one well must be constructed as follows: (i) surface water and stormwater runoff must be diverted away from the pit; (ii) total pit volume may not exceed 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tract of land; (iii) pit sidewalls and bottoms must be adequately cushioned and free of objects capable of puncturing and ripping the liner; (iv) pits constructed in unconsolidated sediments must have beveled walls (45 degrees or less); (v) the pit liner must be sized and placed with	The owner or operator of an HVHF well shall submit . . . (4) Certification that with respect to on-site pits: (i) such pits will be used solely for fresh water and cuttings that result from drilling conducted with air or fresh water, (ii) for single pits a volume of 250,000 gallons will not be exceeded and for multiple pits on one tract or related tracts of land a total volume of all pits will not exceed 500,000 gallons, (iii) to the extent pits are constructed in unconsolidated materials, beveled walls

	sufficient slack to accommodate stretching; (vi) liner thickness must be at least 30 mils; (vii) seams must be factory installed or field seamed in accordance with the manufacturer's specifications; and (viii) for pits used to hold other than fresh water, at least two feet of freeboard must be maintained at all times. § 560.6(a)(4).	(45 degrees or less) must be utilized, (iv) the sidewalls and bottoms of pits are free of objects capable of puncturing or ripping the liner, (v) there is sufficient slack in the liner used in such pits to accommodate stretching, (vi) such pit liners have a minimum 30-mil thickness, (vii) such pit liners are installed and seamed in accordance with the manufacturer's specifications, and (viii) pits are constructed, coated, or lined with materials that are chemically compatible with the substance stored and the environment; § 750-3.4(b)(4).
Secondary Containment	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. The results of this inspection must be recorded and documented by the operator, and available to the department upon request; § 560.6(c)(26)(i).	The following conditions apply to all owners or operators of HVHF operations: (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. § 750-3.11(e)(1)(v).
Record Keeping – Waste Fluids	The Drilling and Production Waste Tracking Form must be completed and such completed forms shall be retained for three years by the operator, transporter and destination facility for any waste removed from the well site and be made available to the department upon request during this period. If requested, the operator shall be responsible for obtaining for the department a copy of any completed Drilling and Production Waste with the original signatures of the transporter and	The HVHF SWPPP must include provisions to meter the volume of all flowback water and production brine with an automatic continuous recording device or equivalent that measures to within five percent (5%) of actual flow. The reports shall be kept on site and furnished to the Department upon request. § 750-3.13(f).

	destination facility for any waste removed from a well site covered by a permit to drill issued to the operator pursuant to Part 552 of this Title. § 560.5(f). If any fluid or other waste material is moved off site by pipeline or other piping, the operator must maintain a record of the date and time the fluid or other material left the site, the quantity of fluid or other material, and its intended destination. § 560.5(g).	The HVHF SWPPP must include provisions to record the volume of all sanitary and non domestic wastewater produced onsite on a daily frequency. The HVHF SWPPP must also include a transportation record of all sanitary and non-domestic wastewater leaving the well pad. The transportation record must include the volume of all sanitary and non-domestic wastewater shipped offsite by individual trucks and/or pipeline, and the name, permit and destination of the receiving reuse and/or treatment and disposal facilities. The HVHF operation must also obtain confirmation that the transferred wastewater was received by the intended wastewater treatment and disposal facility and keep records associated with such transfers. The HVHF SWPPP must include provisions for separately compiling monthly and daily total volumes of flowback water, production brine and sanitary wastewater collected and transported off-site from the well pad and analytical results for any flowback water samples that are taken. The reports shall be furnished to the Department upon request. § 750-3.13(g).
Record Keeping – Miscellaneous	Hydraulic fracturing operations must be conducted as follows: . . . (viii) The operator must make and maintain a complete record of its hydraulic fracturing operation including the flowback phase, and provide such record 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 hydraulic fracturing 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. The record for each well must include all types and volumes of materials, including additives, pumped into the well, flowback rates, and the daily and total volumes of fluid	(b) For the Construction Phase, HVHF Phase, and the Production Phase, all stormwater discharges must be monitored, recorded and reported in accordance with the terms and conditions of applicable individual or general permits to ensure effective operation. § 750-3.13(b). (c) The HVHF SWPPP must include provisions for monitoring and recording the volume of all water delivered to the well pad site from each source. Records must be maintained of each truck/pipeline delivery of water and the source of such water. The reports shall be kept on site and furnished to the Department upon request.

	recovered during the first thirty days of flow from the well. The record must also include a complete description of pressures exhibited throughout the hydraulic fracturing operation and associated pressure recordings, charts and/or pressure profile. A synopsis of the hydraulic fracturing operation must be provided in the appropriate section of the department's Well Drilling and Completion Report, which must be provided to the department within 30 days after completing the well in accordance with section 554.7 of this Title. § 560.6(c)(26)(viii).	§ 750-3.13(c). (d) The HVHF SWPPP must include provisions to meter the volume of water used at each well each time there is high-volume hydraulic fracturing event during the HVHF Phase. The volume must be metered with an automatic continuous recording device (or its equivalent) that measures to within five percent (5%) of actual flow. The reports shall be kept on site and furnished to the Department upon request. § 750-3.13(d). (e) The HVHF SWPPP must include provisions to maintain a record of the amounts of all chemicals/additives associated with each time there is a high-volume hydraulic fracturing stage during the HVHF Phase. This list may exclude any information that has been determined to be confidential business information. The record shall include a list of the individual chemicals/additives with Chemical Abstract Services (CAS) registry number and Material Safety Data Sheets (MSDS). § 750-3.13(e).
Definitions	*See* § 560.2.	*See* § 750-3.2.

Appendix B

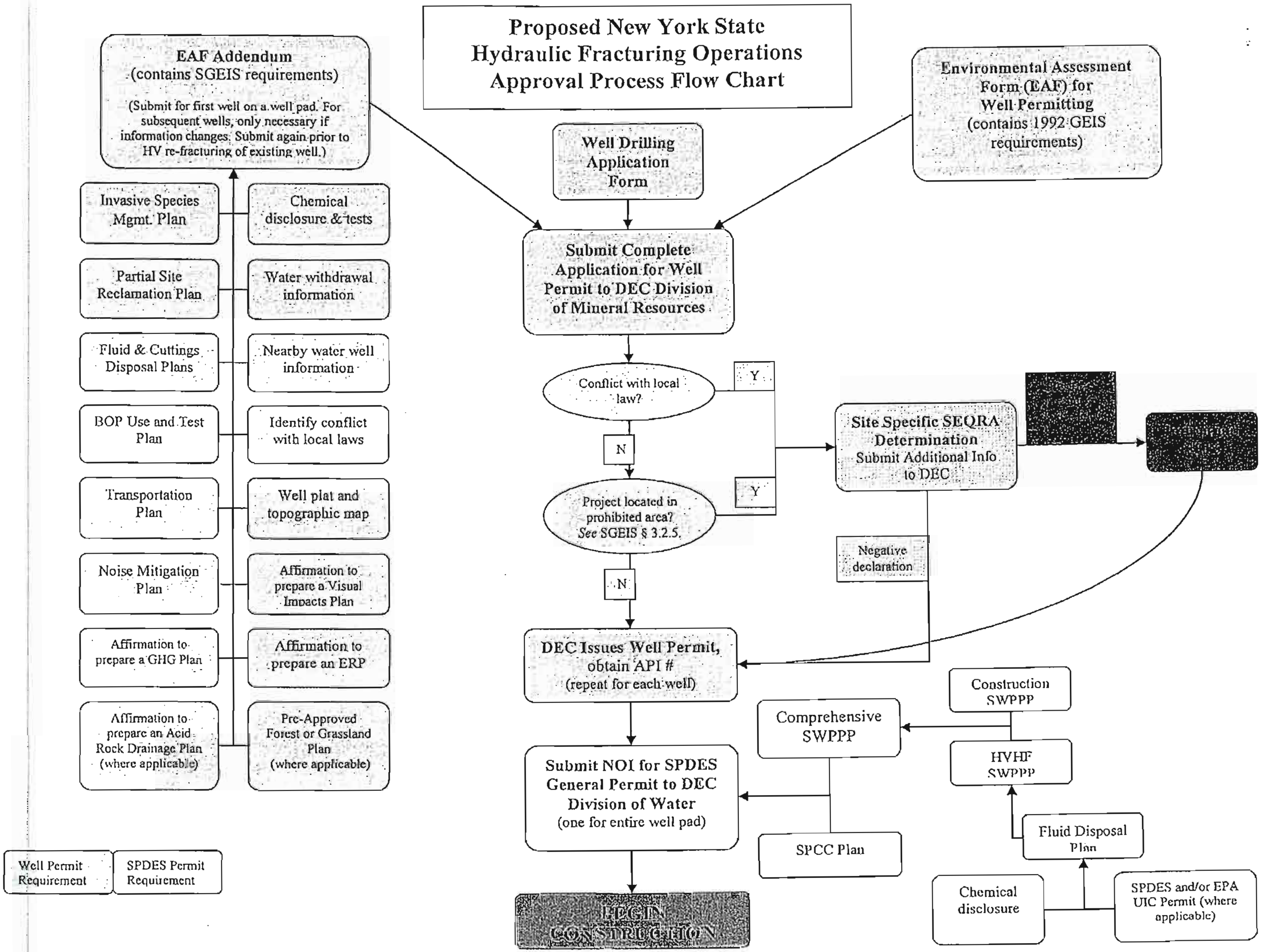
Table 8.1
Regulatory Jurisdictions Associated With High-Volume Hydraulic Fracturing
(Updated August 2011)

Regulated Activity or Impact	DEC Divisions & Offices							NYS Agencies				Federal Agencies			Local Agencies		Other	
	DMN	DEP	DOW	DER	DMM	DFWMR	DAR	DOH	DOT	PSC	OPRHP	EPA	USDOT	Corps	Local Health	Local Govt.	NYC DEP	RBCs
General																		
Well siting	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Road use	-	-	-	-	-	-	-	-	A	-	-	-	-	-	-	P	-	-
Surface water withdrawals	S	-	P*	-	-	P	-	-	-	-	-	-	-	-	-	-	-	P*
Stormwater runoff	S	-	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wetlands permitting	-	P	-	-	-	S	-	-	-	-	-	-	-	P	-	-	-	-
Transportation of fracturing chemicals	-	-	-	S	-	-	-	-	P	-	-	-	P	-	-		-	-
Well drilling and construction	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wellsite fluid containment	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydraulic fracturing/ refracturing	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cuttings and reserve pit liner disposal	P	-	-	A	A	-	-	-	-	-	-	-	-	-	-	-	-	-
Site restoration	P	-	-	-	-	S	-	-	-	-	-	-	-	-	-	-	-	-
Production operations	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gathering lines and compressor stations	S	S	-	-	-	-	S	-	-	P	-	-	-	-	-	-	-	-
Air emissions from all site operations	S	-	-	-	-	-	P*/A*	-	-	-	-	-	-	-	-	-	-	-
Well plugging	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Invasive species control	S	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-	-
Fluid Disposal Plan, 6NYCRR 554.1(c)(1)																		
Waste transport	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-
POTW disposal	-	-	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New in-state industrial treatment plants	-	P	S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Injection well disposal	S	P	S	-	-	-	-	-	-	-	-	P	-	-	-	-	-	-
Road spreading	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	P	-	-
Private Water Wells																		
Baseline testing and ongoing monitoring	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Initial complaint response	S	-	-	-	-	-	-	-	-	-	-	-	-	-	P	-	-	-
Complaint follow-up	P	-	-	-	-	-	-	-	-	-	-	-	-	-	S	-	-	-

Key:
P = Primary role
S = Secondary role
A = Advisory role
* = Role pertains in certain circumstances

DEC Divisions
DMN = Division of Mineral Resources
DEP = Division of Environmental Permits (DRA in GEIS Table 15.1)
DOW = Division of Water (DW in GEIS Table 15.1)
DER = Division of Environmental Remediation (DSHW in GEIS Table 15.1)
DMM = Division of Materials Management
DFWMR = Division of Fish, Wildlife and Marine Resources
DAR = Division of Air Resources

Appendix C


Proposed New York State Hydraulic Fracturing Operations Approval Process Flow Chart
EAF Addendum (contains SGEIS requirements)
(Submit for first well on a well pad. For subsequent wells, only necessary if information changes. Submit again prior to HV re-fracturing of existing well.)
Well Drilling Application Form
Environmental Assessment Form (EAF) for Well Permitting (contains 1992 GEIS requirements)
Invasive Species Mgmt. Plan
Chemical disclosure & tests
Partial Site Reclamation Plan
Water withdrawal information
Fluid & Cuttings Disposal Plans
Nearby water well information
BOP Use and Test Plan
Identify conflict with local laws
Transportation Plan
Well plat and topographic map
Noise Mitigation Plan
Affirmation to prepare a Visual Impacts Plan
Affirmation to prepare a GHG Plan
Affirmation to prepare an ERP
Affirmation to prepare an Acid Rock Drainage Plan (where applicable)
Pre-Approved Forest or Grassland Plan (where applicable)
Submit Complete Application for Well Permit to DEC Division of Mineral Resources
Conflict with local law?
Y
N
Project located in prohibited area? See SGEIS § 3.2.5.
Y
N
Site Specific SEQRA Determination Submit Additional Info to DEC
Negative declaration
DEC Issues Well Permit, obtain API # (repeat for each well)
Construction SWPPP
Comprehensive SWPPP
HVHF SWPPP
Submit NOI for SPDES General Permit to DEC Division of Water (one for entire well pad)
SPCC Plan
Fluid Disposal Plan
Chemical disclosure
SPDES and/or EPA UIC Permit (where applicable)
BEGIN CONSTRUCTION
Well Permit Requirement
SPDES Permit Requirement

Independent Oil & Gas Association of New York

January 11, 2012

dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Subject: High Volume Hydraulic Fracturing Regulatory Proposals

Dear Commissioner Martens:

The Independent Oil and Gas Association of New York ("IOGA") respectfully submits the following comments regarding the revised draft Supplemental Generic Environmental Impact Statement ("rdSGEIS"), the associated rule-making, and the parallel effort to expand the general permit program relative to stormwater discharges from natural gas drilling and completion activities. From an organizational standpoint, IOGA's comments are set forth as attachments to this letter. The first tab is an analysis of Critical Issues to the Oil and Gas Industry in New York State. The second tab includes comments on the rdSGEIS. The third tab includes comments on the proposed regulations, including suggested textual revisions to those regulations. The last tab includes comments on the proposed General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing. The remainder of this letter sets forth important issues for New York State to consider as it finalizes these regulatory proposals if we are to achieve the shared objective of ensuring the environmentally responsible development of clean burning natural gas resources in New York State and the many economic, environmental and energy security benefits that would come from New York State taking full advantage of this extraordinary opportunity.

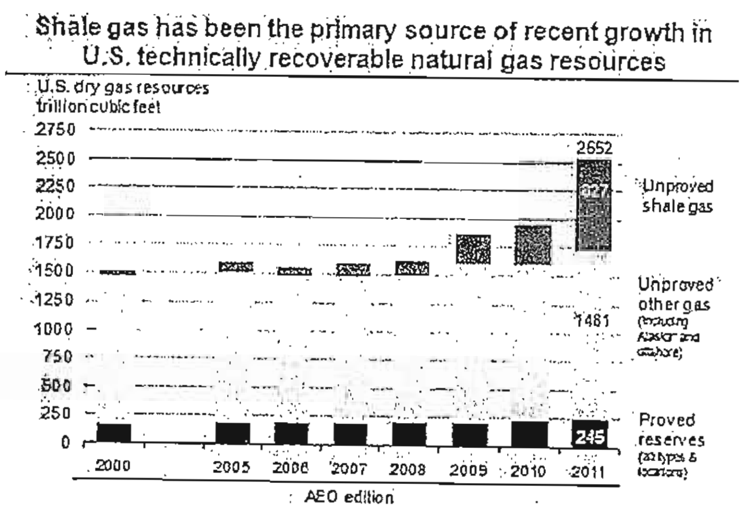
At the outset, it is important to stress that IOGA supports a high environmental bar in New York State. IOGA believes that industry's outstanding track record in New York State coupled with the heightened scrutiny required by a modernized regulatory framework will lead to the safe and responsible development of valuable indigenous natural gas resources in New York State without compromising environmental quality. That being said, regulatory requirements must take care not to unduly burden the public and private sector with requirements that do not have any corresponding benefit to environmental quality or public safety. There are many such examples that are detailed in the attachments to this letter, which we urge the DEC to carefully consider as it finalizes these regulatory initiatives.

IOGA estimates that if every one of the innumerable mitigation measures required in the revised draft regulations is put into place that the cost to apply for and obtain permits in New York State will exceed those in neighboring states by as much as $1 million per wellbore. While we fully share the DEC's commitment to safe and responsible development, we feel that many of the requirements do not serve this objective, which will put New York at a significant competitive disadvantage. Our attached, detailed comments identify a number of proposed mitigation measures that are not currently used, not readily available and/or have no documented ability to deliver any additional needed layer of environmental protection. In short, in their current state, the DEC's proposals to regulate high-volume hydraulic fracturing ("HVHF") will put New York at a competitive disadvantage to neighboring states and cost New York State and its residents billions of dollars in lost economic opportunity. It is our distinct hope that the public comment process will lead to reasonable and balanced improvements to the regulatory proposals in order to ensure that New York can achieve its dual objectives—protecting natural resources while reaping the many benefits of responsible natural gas development in our state.

Shale Gas Economics

According to the U.S. Energy Information Administration (EIA), the majority of recent increases in natural gas production and potential are resulting from the emerging shale gas plays (see **Figures 1** and **2**).[6]

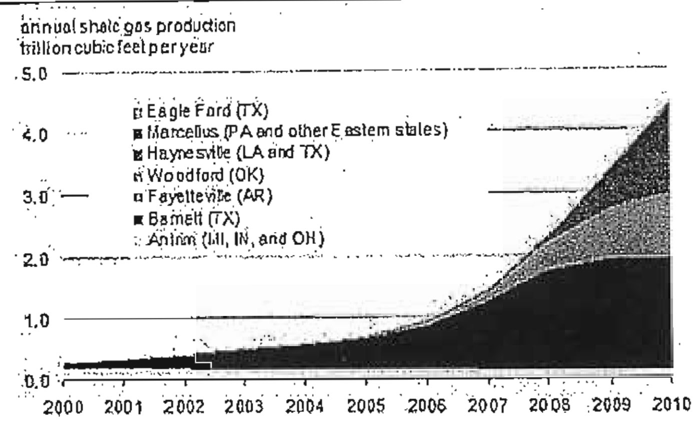
Figure 1



Source: Richard Newell, "Annual Energy Outlook 2011 Reference Case," U.S. Energy Information Administration, presented December 16, 2010, http://www.eia.gov/neic/speeches/newell_12162010.pdf (accessed August 18, 2011).

Figure 2

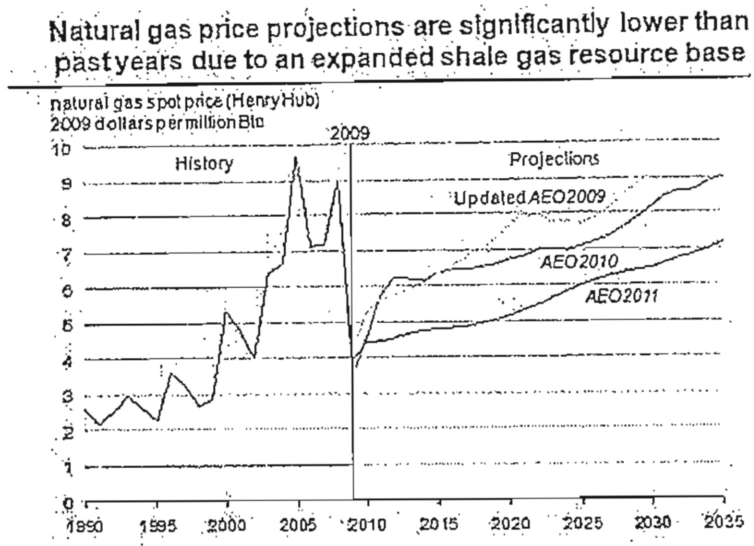
U.S. shale gas production increased 14-fold over the last decade; reserves tripled over the last few years



Source: Richard Newell, "Annual Energy Outlook 2011 Reference Case," U.S. Energy Information Administration, presented December 16, 2010, http://www.eia.gov/neic/speeches/newell_12162010.pdf (accessed August 18, 2011).

Currently (December 30, 2011), the Henry Hub average spot price for natural gas is $3.043 per million British thermal units (MMBtu). The average spot price in 2012 is expected to be roughly similar. For the last several years, the market prices have been low and are continuing to track at low levels because of high rates of production.[7] EIA's current outlook for natural gas prices does not rise above $5.00/MMBtu until approximately 2020 (see AEO 2011 curve on **Figure 3**). Furthermore, for the past three years EIA's long-term projections have predicted lower and lower prices with each year's revisions (see AEO 2009, AEO 2010, and AEO 2011 curves on **Figure 3.**

Figure 3



Source: Richard Newell, "Annual Energy Outlook 2011 Reference Case," U.S. Energy Information Administration, presented December 16, 2010, http://www.eia.gov/neic/speeches/newell_12162010.pdf (accessed August 18, 2011).

Figure 2 also demonstrates that there is significant unconventional gas drilling activity in a variety of plays under different state regulatory regimes. Without reasonable modifications to the proposed regulations, there is likely to be a significantly higher cost for operating in New York versus other shale gas states. This risks placing New York State at a competitive disadvantage, without—as noted above—delivering any meaningful additional safeguards. This would deny New York State the full economic and other benefits that natural gas abundance offers.

In the face of a challenging economic environment, operators will take into consideration where (geographically) their exploration budgets are best allocated. Shale plays such as the Bakken (oil) in Montana and North Dakota, the Eagle Ford Shale (condensate) in Texas, and the Utica Shale (oil) in Ohio, are rich in liquid hydrocarbons, which significantly improve the drilling economics for these plays in comparison to a dry gas play, such as is expected for the Marcellus in New York.

Compounding these economic realities is the fact that the productivity of the shale resources in New York remains unproven. There are many factors that can affect future development of the shale resources in New York, not the least of which are depth, thickness, organic content, and thermal maturity of the formation. In fact, many operators anticipate that the intersection of these critical geologic factors will be less favorable in New York than they are in neighboring Pennsylvania based upon core data and other geologic indicators.

Both for its environment and its economy, New York State has an extraordinary stake in getting the rules right. All parties share a powerful and compelling stake in ensuring the resource is developed responsibly and local natural resources are protected. And, if we do not embrace rules that allow for responsible, cost-effective development, the burden is shared broadly:

- For operators:
  - Leases would be lost at great cost because wells could not be drilled in time to satisfy lease requirements due to delays in finalizing the SGEIS.
  - Leases would be lost at great cost because of excessive setbacks and unnecessary prohibitions on drilling.
  - Leases would be lost because there will not be enough contiguous acreage that can be assembled to provide the necessary reserves for economically viable prospects.
- For mineral rights owners:
  - With no production from their mineral rights, owners would be denied their royalties, which is estimated to total more than $19 billion in a four county area.
  - Many mineral rights owners would lose potential bonus payments because of the prohibitions and setbacks and the noncompetitive nature of New York State's regulatory environment, which is estimated to total more than $2 billion in the same four county area.
- For business owners:
  - Hotels, restaurants and other 'main street' businesses would be unable to participate in the substantial economic gains witnessed in other shale-rich parts of the country. Some of the development areas are already economically challenged and in desperate need of these revenues.
  - Companies providing direct services to the gas industry would continue to be reluctant to establish offices in New York to support an industry with an uncertain local future, particularly when the opportunities are much more attractive and certain in neighboring states where drilling and production are already occurring in more favorable regulatory and economic climates.
- For local and state governments:
  - New York has already lost major economic opportunities as operators and service companies have already established permanent offices/facilities in the Northern Tier of Pennsylvania.
  - New York State would continue to lose income taxes on bonus and royalty payments for mineral rights and the substantial income that would come from direct and secondary expenditures associated with the companies and businesses providing services to natural gas industry.

- New York State and municipalities would lose revenue from bonus and royalty income associated with minerals leasing of state and municipal mineral rights.
- Municipalities and school districts would lose the tax revenues that result from the robust *ad valorem* tax system applicable to oil and gas development in New York State that would be lost at a time when it is most needed. Cumulatively, the lost income and ad valorem taxes are estimated to total more than $5.8 billion in the same four county area.

- For the citizens of New York:
  - All citizens would lose the benefits of tax revenues that would be reinvested in state and community infrastructure and services.
  - All citizens would lose the benefits of participating in the potential economic growth that would come with gas development.
  - All citizens would lose the tax revenues from bonus payments, royalty payments and the sales of goods and services.
  - All citizens would lose the benefits of an expanded supply of a clean burning, indigenous resource to offset coal and foreign oil.

These are but a few of the examples of opportunities that have been and/or will be lost without an opportunity for timely and economically viable development of shale gas resources. Of course, the exact opposite could be true: all of these opportunities would open to New York at a critical time if a more appropriate and balanced path forward can be constructed through the remainder of this process. As New York State moves forward, we urge you to engage constructively with our community to reach a workable outcome that opens New York State up to the opportunities of natural gas development. We believe the ultimate objective should be to establish the nation's most effective rules that protect the environment while still promoting economic development, and we stand ready to work with New York State to achieve this goal.

Summary

IOGA shares DEC's desire for a well-informed regulatory framework that is simultaneously protective of the environment while encouraging the investment of capital and the creation of jobs and wealth. Many of the safeguards imposed by the rdSGEIS are appropriate and effective. However, without improvement, the more excessive, unproven and unnecessary limitations run the substantial risk of making the exploration and development of unconventional natural gas in New York non-economic. As a result, New York's regulations and requirements, if finalized without amendment, will be viewed by industry as too challenging and restrictive to allow for cost-competitive development in the current and forecast natural gas market.

The regulatory proposals currently being put forth by the DEC do not yet send the signal that New York State is receptive to working with all parties for the safe and responsible development of its natural resources or that New York is open for business. It is imperative that DEC effectively safeguard its environment and people. Likewise, it is imperative that New York State do so in a manner that allows New York to capitalize on the extraordinary opportunities presented by the state's natural gas resources. And, it is imperative that New York demonstrate to the nation that its people do not have to choose between environmental protection and economic development. Through appropriate oversight and the strong commitment of the natural gas industry to responsible development, the people of New York can indeed have both.

The natural gas community stands ready to work with New York State in good faith to ensure that such a timely and appropriate balance is struck in the final standards.

Sincerely,

Independent Oil and Gas Association of New York,

Brad Gill Executive Director

cc: Andrew M. Cuomo, Governor (with only Tab 1 enclosed)
Joseph Martens, Commissioner (with only Tab 1 enclosed)
Marc Gerstman, Executive Deputy Commissioner (with only Tab 1 enclosed)
Eugene Leff, Deputy Commissioner (with only Tab 1 enclosed)
Steven Russo, Esq., General Counsel (with only Tab 1 enclosed)
Bradley J. Field, Director, Division of Mineral Resources (with only Tab 1 enclosed)
Jennifer Maglienti, Esq. (with only Tab 1 enclosed)
Thomas S. West, Esq., The West Firm, PLLC (w/o enclosures)
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J. Daniel Arthur, PE, SPEC, ALL Consulting (w/o enclosures)

CRITICAL ISSUES TO THE OIL AND GAS INDUSTRY IN NEW YORK STATE

Submitted by the Independent Oil and Gas Association of New York
January 11, 2012

The Independent Oil and Gas Association of New York ("IOGA") submits this analysis of critical issues that have been identified by IOGA in response to the New York State Department of Environmental Conservation's ("DEC") revised draft Supplemental Generic Environmental Impact Statement ("rdSGEIS"), proposed regulations for high-volume hydraulic fracturing and proposed stormwater general permit (collectively, "Regulatory Proposals").

Executive Summary

- The DEC's Regulatory Proposals, and in certain instances, proposed mitigation measures, are based upon unrealistic, worst-case scenarios that impose costly and time-consuming requirements that do not meaningfully advance the collective goal of advancing safe and responsible development in the State of New York. Substantial improvements are needed to ensure an effective regulatory program that achieves the dual objectives that we all share, safeguarding the environment and promoting the development of the State's clean burning indigenous natural gas resources.

- Without change, these proposals will render shale gas in New York non-competitive.

- They will, in addition, place small businesses at a disadvantage.

- The concept of Best Management Practices ("BMP") is misused resulting in mitigation that is too prescriptive and without sufficient flexibility to accommodate future technological innovations.

- Together, the preceding factors run the substantial risk of making the exploration and development of unconventional natural gas in New York uneconomic.

- Consistent with the foregoing, it does not appear that any consideration has been given to the timely processing of permit applications in New York State in order to lessen regulatory burdens, reduce staffing needs and promote natural gas development. The many sequential agency and intra-departmental reviews and coordination with river basin authorities that are contemplated by the process are too cumbersome and will not work in practice.

- Without a scientific basis or rationale, there are significant setbacks and prohibitions proposed that will make it extremely difficult to lay out spacing units and locate well pads. Industry evaluation of actual acreage controlled by several operators reveals that this will have the effect of reducing the available acreage by as much as 50%. Compounding this result is the fact that industry will be forced to use smaller units, which will have the unintended consequence of increasing surface disturbance by requiring a greater number of well pads. The opposite should be encouraged through the implementation of reasonable setbacks, consistent with existing regulatory setbacks that have worked well in practice and with thousands of wells that have been drilled in New York State to date. In addition, all setbacks and prohibitions should be subject to a waiver process where good cause is shown why the setbacks and prohibitions will strand acreage and resources without any real environmental benefits. Lastly, any prohibitions and setbacks that are contemplated to be revisited in several years should expire automatically unless extended by formal order of the Commissioner.

- The water quality regulations are predicated upon the false pretense that an individual State Pollution Discharge Elimination System ("SPDES") permit is required for hydraulic fracturing, but then the regulations establish an exemption for the stimulation technique itself. This is nonsensical and conflicts with existing law since hydraulic fracturing does not involve a discharge to the waters of New York State. In addition, the regulations contain many definitions and requirements that duplicate the definitions and requirements contained in the proposed, as well as existing, comprehensive minerals regulations. Often, there are subtle differences between the regulatory definitions, which will lead to utter confusion. Compounding these problems is the fact that the water quality regulations contemplate sequential review of water quality issues after a drilling permit has been issued. This will lead to duplicate review of many issues, which is the hallmark of regulatory inefficiency, as well as unnecessary delay.

- The water quality review should be limited to the implementation of a multisector general permit applicable to stormwater discharges from the construction of well pads and other disturbed areas implemented in accordance with existing requirements. Although such a permit is contemplated, the proposed new permit is unnecessarily complicated and requires detailed chemical and radiological analysis of stormwater discharges, which is not required for any other industry in New York State. In effect, the proposed stormwater permit abandons the concept of "benchmark testing" by proposing detailed and costly testing requirements that exceed the testing requirements for most SPDES permits in effect today, including those permits that regulate sophisticated chemical operations. Stormwater discharges from well pads can be safely, reliably and cost-effectively monitored through the existing benchmark standards that include total suspended solids, pH and chlorides. Any discharge from a well at a well pad is likely to include chlorides, which is why chlorides are a common and appropriate benchmark standard for the natural gas sector.

- The regulations propose to eliminate the limit on the bonding required for each well as well as multiple wells where a single operator operates multiple wells. Since shale gas wells are likely to be operated for decades, this will lead to unnecessary bonding costs and will unnecessarily tie up capital. Reasonable limits for individual wells and cumulative limits for well operators should be maintained in the regulations. Bonding is only necessary where a well operator defaults on its plugging and abandonment responsibilities, which has not occurred under the modern-day oil and gas program in New York State.

- Based upon worst-case scenarios, many of which will never occur, the DEC proposes unrealistic air mitigation measures, many of which are unavailable or impracticable as well as preempted by the Clean Air Act. They also cannot be justified or sustained by reliance on the State Environmental Quality Review Act ("SEQRA"). In addition, the DEC fails to take into account the significant changes that are being proposed by the United States Environmental Protection Agency ("EPA") to regulate air emissions from drilling and stimulation activities.

- In disregard for the statutory mandate that the DEC balance competing uses of water in New York State, the proposed SEQRA mitigation measures and regulatory proposals seek to implement the Natural Flow Regime ("NFR") as a minimum flow requirement on all water withdrawals exclusively for the natural gas industry, including water withdrawals subject to federal interstate compact commission approval by the Susquehanna River Basin Commission ("SRBC") or the Delaware River Basin Commission ("DRBC"). The NFR does not balance competing interests and is unnecessarily conservative in its approach. In addition, the use of the NFR method, specifically in the Susquehanna River Basin, often results in a more stringent flow requirement than would be required utilizing the methodologies practiced by the SRBC. This is in direct conflict with the New York State 2011 water withdrawal legislation (Laws of 2011, ch. 401) which provides an express exemption for water withdrawals approved under the purview of the federal interstate compact commissions.

- Rather than leave local road issues to agreements between operators and municipalities, the DEC is proposing that all operators submit a road transportation plan, which, among other things, must be reviewed by the New York State Department of Transportation ("NYDOT"). This will cause unnecessary delay and lead to additional staffing needs that are unnecessary and interject the State into what is primarily a local issue subject to express local jurisdiction.

- The proposed mitigation measures and regulatory proposals require each operator to perform a "green" frac analysis for each well permit application even though the industry has made great strides in greening frac fluid additives. This will lead to significant cost and delay, and there are no standards identified for review of the analysis. Since the operator and the service company are responsible for determining efficacy to maximize the recovery of the natural resource, the agency should abandon this requirement or adopt a more generic alternative.

Worst Case Scenarios

Much of the rdSGEIS and the regulatory proposals that are based upon the rdSGEIS rely too heavily on worst-case scenarios as purported justification. This is improper in the context of SEQRA and has led to a number of Regulatory Proposals that are unnecessarily conservative, all of which have the impact of driving up the cost of compliance without any corresponding benefit to the environment or public safety. This has the impact of making shale gas development in New York economically non-competitive with other neighboring states, which drive out the few remaining players and stifle the return of industry to New York State.

In spite of credible information and reasonably foreseeable industry projections provided by IOGA, the DEC has opted to analyze worst-case scenarios as if they are expected-case scenarios for many impact topics. For example, in the case of number of horizontal wells drilled per year, IOGA provided the DEC with reasonable projections of the average number of horizontal and vertical wells anticipated by industry to be drilled in New York over the next 30 years. Along with these average projections, IOGA included an estimate of peak year drilling rate (maximum) reflecting typical patterns of field development (i.e., a gradual ramping up of exploration, development and production to a peak drilling rate followed by a long period during which drilling rates would decline to approach zero). Instead, in its estimate of cumulative water withdrawal impacts, the DEC has used the peak rate as if it were the norm. Furthermore, the DEC has assumed that all wells included in the peak rate are horizontal wells. Thus, the DEC has chosen to "double-down" on the worst-case scenario by intentionally disregarding IOGA's estimate for horizontal and vertical well drilling rates and simply assumes that the sum total should be applied as if all wells were horizontal. Because horizontal wells use considerably more make-up water for hydraulic fracturing than do vertical wells, this results in an overestimate of cumulative withdrawals.

Additional examples can be found in the DEC's air emissions dispersion modeling analysis which used unnecessarily conservative input data and assumptions resulting in very restrictive and mandatory mitigation measures, most of which are not available to the industry. This was done in spite of credible information provided to the DEC by IOGA. The DEC opted to analyze worst-case scenarios as if they were the expected-case for all situations.

Again, such an approach is outside the definition of "reasonably foreseeable." As a result of these and other ultra-conservative assumptions, the industry is now confronted with required mitigation strategies based on unrealistic, worst-case assumptions. These are but a few examples of an over-arching, worst-case approach that DEC has employed throughout the rdSGEIS.

Permit Processing

It does not appear that any significant thought has been given to the amount of time that it will take to process a permit application in New York State following the completion of the SGEIS and associated regulatory processes. The rdSGEIS and the proposed regulations contemplate review by multiple state agencies and divisions within the DEC and, potentially, coordination with one or more federal interstate compact commissions, but there is no plan for how this will be accomplished in a timely manner. Compounding this problem is the fact that many of the reviews are contemplated as being sequential (e.g., the requirement to process the permit application for a minerals permit under Part 560 prior to seeking qualification for a stormwater general permit.).

Nowhere in the document is there a clear table and flowchart of what is required in a permit application to drill a well. More importantly, there are both internal and external points of approval for specific reports, plans and requirements. There are no timeframes associated with approvals to be obtained from both inside and outside the DEC. Therefore, a great deal of regulatory uncertainty in the process exists. Companies that invest in New York need to know the ground rules and a predictable and timely process to make their investment decisions. The rdSGEIS is deficient in setting forth an application framework and relative timeframe for approval. Without these basics, timing of investments, commitments to contractors, and even length and terms of property owners' leases cannot be reasonably assured.

One of the factors that made New York competitive in the past was the prompt turnaround for drilling permits. Prior to the implementation of the current regulatory proposals, it was typical to obtain a drilling permit in six weeks. There is no guarantee under the programs that are the subject matter of the current proposals that an operator will be able to get a permit in six months. Moreover, in many cases, it will take far longer given the requisite biological and other studies (e.g., aquifer testing) that are contemplated as a predicate to the permit application process. At a time when the New York State government needs to be "smart sized" and more efficient, it is inappropriate to propose multiple layers of review. As an alternative, the DEC should create a "user-friendly" permit application process that has all of the staff necessary in DEC's Minerals Division to process the permit application expeditiously.

A further example of the confusion that exists concerning how permit applications will be processed is the role contemplated for local governments. Notwithstanding a 30 year history of interpreting ECL § 23-0301(2) as preempting all efforts by municipalities to regulate or zone natural gas drilling and stimulation activities, the rdSGEIS seemingly reverses this history and contemplates a role for municipalities in the siting and permitting process. The rdSGEIS also proposes as a catch-all mitigation measure that the DEC will consult with local municipalities regarding the timing of development and will limit drilling permits to avoid potential impacts on community character, tourism and other socioeconomic impacts (e.g., visual, noise and road impacts) associated with concentrated development. rdSGEIS, § 7.11.3. This requirement is of grave concern.

It is unclear how the DEC will limit permits and how this will impact pending applications by various operators, including operators facing lease expirations. There also are no standards articulated for when limits should be imposed, how limits would be imposed or the length of time for any limits. This creates significant uncertainty for industry, jeopardizes lease holdings and makes New York anti-competitive. It also runs counter to the statutory mandates for shale wells to drill "all horizontal infill wells in the unit to be drilled from a common well pad within three years of the date the first well in the unit commences drilling" ECL § 23-0501(1)(b)(1)(vi). Further, involving local municipalities in the calculus, some of which may or may not favor drilling, flies in the face of the ECL's express preemption over local regulation of the industry.

IOGA has submitted a written analysis demonstrating the reasons why municipalities are preempted from regulating any aspect of natural gas drilling, with the narrow exceptions of the regulation of roads and local taxation. There are now two court cases pending challenging municipal bans, one in the Town of Dryden and another in the Town of Middlefield. The DEC should follow its long-standing precedent and await the outcome of these court cases before suggesting any role for municipalities in the well permitting and siting process, beyond issues associated with roads and local taxation.

Setbacks and Prohibitions

Without a scientific basis or rationale, the DEC has proposed a series of prohibitions and setbacks at a scale never before contemplated, despite New York's long-standing history of natural gas exploration and development. Some of these prohibitions and setbacks preclude any development while others preclude the siting of well pads within prohibited areas. When these prohibitions and setbacks are mapped against leasehold interests, it often becomes impossible to lay out units or site well pads in a manner that makes development in New York State economically viable. As a consequence, operators will lose hundreds of millions of dollars already invested in minerals leases and related geological assessments, landowners will lose millions of dollars in royalties, significant tax revenue will be lost, and very few operators, if any, will be willing to invest their drilling budgets in New York State. The result will be lost economic opportunity for New York totaling billions of dollars as well as a flagrant disregard of the State's repeated policy objectives to further oil and gas development.

New York State's ECL, as it pertains to oil and gas, has long since been recognized as a "conservation statute" that is designed to prevent waste, promote the recovery of the resource and protect the correlative rights of landowners. Consistent with that goal, ECL § 23-0301 declares that it is in the public interest to "regulate the development, production and utilization of natural resources of oil and gas in this state in such a manner as will *prevent waste; to authorize and provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners* *and the rights of all persons including landowners and the general public may be fully protected* [emphasis added]." Likewise, subdivision 5 of §3-101 of the New York Energy Law declares that it is part of the energy policy of New York State "to foster, encourage and promote the prudent development and wise use of all indigenous state energy resources including, but not limited to on-shore oil and natural gas...[and] natural gas from Devonian shale formations..." These guiding principles serve as the basis for the oil and gas regulatory framework in New York State.

In furtherance of these goals and objectives, New York State has created detailed statutory schemes for spacing and compulsory integration to promote the greater recovery of the resource and protect correlative rights. The spacing and permitting provisions are generally found in ECL Article 23, Title 5. In accordance with the fundamental policy, ECL § 23-0503(2) authorizes the issuance of permits to drill wells if a proposed spacing unit "conforms to statewide spacing and is of approximately uniform shape with other spacing units within the same field or pool, and abuts other spacing units in the same pool, unless sufficient distance remains between units for another unit be developed." For the unconventional, continuous plays like the Marcellus and the Utica, this is likely to require relatively uniform rectangular-shaped abutting units in order to avoid gaps in the development of the resource.

Also paramount in the well permitting process is the need to site a well pad in a location that minimizes environmental impacts to the maximum extent practicable. This is frequently accomplished by looking for locations that avoid stream crossings, wetlands, steep slopes, endangered species, and known areas of historic significance, and by taking into account other siting considerations consistent with BMPs. The existing regulations found in 6 NYCRR § 553.2 contain appropriate setbacks that have worked well for decades and have not led to any demonstrable problem with the 14,000 operating wells in New York State.

Against this backdrop, the DEC is proposing a series of additional setbacks and prohibitions. These include the following:

- Prohibitions:
  - the prohibition of well pads in the New York City and Syracuse watersheds and a buffer zone that is 4,000 feet around those watersheds;
  - primary aquifers and a surrounding 500 feet buffer; and
  - certain State lands (State Forests, State Parks, etc.).
- Setbacks:
  - within 2,000 feet of a primary aquifer;
  - within 2,000 feet of public water supply wells and reservoirs; and
  - within 500 feet of private drinking water wells or domestic use springs, unless waived by the owner, and within 100-year floodplains.

The proposed rdSGEIS also declares that a supplemental environmental analysis (i.e., a site-specific Environmental Impact Statement ["EIS"]) will be required in certain instances. These instances cover three categories: location, drilling depth and type of water-related issues. The location carve-outs require a site-specific EIS:

- within 1,000 feet of New York City's subsurface water supply infrastructure;

- within a principal aquifer and surrounding 500 feet buffer (this would also require an individual SPDES stormwater permit);
- within 150 feet of a perennial or intermittent stream that is not a tributary to a public drinking water supply, storm drain, lake or pond; and
- within 500 feet of a tributary to a public drinking water supply.

Furthermore, private lands with tracts of grassland greater than 30 acres or forest greater than 150 acres in Focus Areas may be off limits to surface occupancy and/or severely restricted insofar as their future development potential is concerned. The definitional structure is poorly crafted in that it makes reference to contiguous patches of these lands. If the lands are not contiguous, they should not require any further analysis. As proposed, these areas would require extensive studies prior to permitting, which requires at least one year of study before and two years of study after completion of the well. IOGA questions whether the DEC has the legislative authority to impose such restrictions on private lands.

Moreover, the setbacks proposed by the DEC are to the "edge of location" (i.e., the well pad), not to the well itself. Therefore, all estimates of acreage excluded from development must add an additional 200 feet from the restricted area/edge of surface disturbance to the centrally located well, which increases the setbacks significantly.

As an initial matter, the proposed prohibitions directly conflict with the policy objectives of the statutory scheme in that they fail to promote the recovery of the resource or protect the correlative rights of the landowners in the prohibition areas. For this reason alone, the prohibitions should be eliminated. A clear example of this is the prohibition on drilling on state land even though New York State has a long track record of leasing state land for surface activities associated with natural gas drilling. Given the size of many of the state forest tracks, this will leave large undeveloped areas, which will hurt neighboring landowners and the municipalities in which the state land tracts are located from the loss of tax revenue.

Regarding the setbacks, although some reasonable setbacks are not objectionable (e.g., the existing regulations), when multiple setbacks are established without the authority of the DEC to grant waivers for good cause shown, it becomes extremely difficult, if not impossible, for an operator to lay out units in an orderly fashion. Further complicating this issue is the trend in the industry to drill longer horizontal wells, thereby reducing the number of well pads that are required. This trend further reduces the surface footprint of the industry and corresponding impacts to the environment. Because New York law limits the size of spacing units for shale wells up to 640 acres, it will be the practice of most industry operators to lay out back-to-back units with a common well pad for both units thereby draining areas up to 1,280 acres (two square miles). As such, the location of the well pad becomes a critical factor in laying out spacing units based upon mineral lease rights and other environmental considerations.

By way of example, one operator has laid out spacing units based upon back-to-back 640 acre unit spacing, its mineral leases and traditional factors to avoid sensitive environmental areas. In the Owego area of Tioga County, this operator has sufficient mineral rights to develop twelve 640 acre spacing units with back-to-back spacing units and common well pads. Unfortunately, when land constraints are overlaid with the regulatory setbacks being proposed by the DEC, only two of the units are feasible. Because the spacing law allows spacing "up to" 640 acres, this operator may be able to develop other smaller units, but taking such an approach will increase the number of well pads significantly, thus increasing the cost to the operator (including, but not limited to, the significant cost to prepare a greater number of permit applications and the regulatory fees associated with those applications) and increasing both the surface impacts and truck traffic. Even then, certain areas will be inaccessible, with the consequence that millions of dollars already invested in leases will not be practical to develop. Of equal importance is the fact that landowners and municipalities will lose the revenues associated with the development of this acreage.

Another operator has gone through a similar exercise in Chemung County, New York. The primary aquifer provision will eliminate significant developable acreage. This operator estimates that 50% to 60% of their current leasehold in Chemung County is located in primary aquifer areas. And, this prohibition is being proposed even though the same operator has developed four Trenton Black River wells through the very same primary aquifer without any environmental contamination. It is difficult to understand the rationale behind the prohibition for Marcellus-type wells while Trenton Black River wells are allowed to proceed. The primary aquifer prohibition and the many other setbacks proposed will require abandonment of attractive and logical drill sites and cause losses to the operator, mineral owners and municipalities amounting to hundreds of millions of dollars. This will also drive locations out of valleys and onto the more visible, timbered slopes, which is illogical from a resource protection standpoint.

Given the foregoing, industry predicts that the acreage available to develop the shale resources in New York is far less than the 80% being predicted by the DEC and may approach numbers as low as 40% to 50%, if not lower. This situation will:

1. leave large tracts without development of the resource in direct contrast to the ECL's statutory directives;
2. subject operators to lost investments and development potential;
3. preclude landowners from reaping billions of dollars of economic benefits from the development of shale resources in New York State;
4. deny significant tax revenue to local municipalities as well as the State;
5. encourage the development of smaller units resulting in greater surface disturbance; and
6. deter most, if not all, operators from giving any serious consideration to developing any unconventional plays in New York State (i.e., the Utica as well as the Marcellus).

The overall result will be a large amount of stranded acreage that will not be drilled, leaving natural gas in the ground along with landowners who will be economically impacted and who will not understand why their land will not be drilled when neighboring properties have reaped the benefits.

IOGA estimates that the lost economic opportunity due to prohibitions and setbacks in the Marcellus Shale in just four New York counties (Broome, Tioga, Chemung and Steuben) could exceed $19 billion of royalty income and $2 billion of lease bonus income that would remain unrealized by mineral rights owners. Furthermore, the State and its citizens will not benefit from potential tax revenues of as much as $5.8 billion ($4.4 billion in ad valorem taxes from production and $1.4 billion in personal income taxes from royalty owners). Assuming that the shale plays extend beyond these four counties and also to other shale resources (e.g., the Utica Shale), then the unrealized income and taxes is likely to be considerably greater. Furthermore, these numbers do not take into account the lost income to the operators or the many local businesses that will service the oil and gas industry and pay taxes on their income.

As an alternative, the industry recommends that many of the setbacks be eliminated or reduced to the existing setbacks, or setbacks that are consistent with those in place in other neighboring states. Industry further recommends that broad waiver provisions be included in the regulations to allow setbacks to be waived by the DEC for good cause shown. Finally, for the prohibitions or setbacks that the DEC is proposing to revisit in a given period of time, it would be far better to have those provisions automatically sunset. That way, those areas would be restored for development after an appropriate phasing period without the need for the DEC to go through the rulemaking process to change the prohibitions. Certainly, the DEC will face considerable opposition and litigation if it initiates a rulemaking to remove certain prohibitions and setbacks, which will have the effect of making those prohibitions and setbacks becoming permanent or semi-permanent until the litigation is resolved. By including an automatic sunset provision, the DEC would still be able to extend those provisions by emergency rulemaking, if warranted, but would be in a far better position to open up more areas of the state for natural gas production consistent with the statutory mandate set forth in ECL § 23-0301. Alternatively, the DEC could make these prohibitions and setbacks sunset automatically unless extended by an order of the Commissioner. This would also give the DEC total control and flexibility concerning the longevity of these impacts without having to go through a formal rulemaking process to terminate the requirements.

Water Quality Regulations

In an effort to deal with criticism from environmental stakeholders about the need for environmental regulations, the DEC has proposed two sets of comprehensive regulations. The first proposal amends 6 NYCRR Parts 551-556 and adds a new Part 560 to incorporate many of the substantive requirements in the rdSGEIS into formal regulations. In addition, the DEC has also proposed extensive regulations in 6 NYCRR Parts 750.1 and 750.3 relative to high-volume hydraulic fracturing ("HVHF") and regulatory requirements that apply to an individual permit under the State Pollution Discharge Elimination System ("SPDES") program or a general stormwater permit.

As an initial matter, there is no need for separate regulations concerning HVHF in the water program given the proposed comprehensive regulations set forth in the new Part 560. This will lead to confusion and a duplication of resources both at the private and public sector levels. For example, the proposed water quality regulations set forth a number of new definitions in proposed § 750-350.2. A number of these definitions are the same as those contained in the proposed mineral regulations; however, there are sometimes subtle but important differences in how terms are defined. Moreover, there are times when the proposed regulations conflict with existing definitions in the existing regulations. Lastly, there are some definitions that are not used in the text of the regulatory proposal.

Similarly, there are a number of substantive requirements proposed in the water quality regulations that parallel or duplicate the requirements set forth in the proposed Part 560. A far better practice that would be less confusing and provide greater regulatory certainty would be to include all of the substantive requirements in one place. That one place should be in the mineral regulations. If a particular document needs to be certified to be consistent with the requirements of the water program, that requirement can be contained in the minerals regulations.

Similarly, the water regulations contain different prohibitions and setbacks. The regulated industry, the public, and even the regulators themselves would be better served if there was a single set of prohibitions, setbacks and other requirements that relate to the extent to which surface activities or subsurface activities will be impaired in a single location, namely, the Part 560 regulations.

Another example where it appears that the Regulatory Proposals are at odds with what happens in practice is the confusion in the draft regulations and the rdSGEIS concerning how drilling and stimulation are phased in and out at a particular well pad over time. This confusion is highlighted in the proposed water quality regulations, which seem to contemplate a bright line distinction between various phases of the operation. In practice, drilling and stimulation do not occur at the same time, but different operators have different formulas for how many wells they drill prior to stimulation and how long it will be following drilling and stimulation before additional wells will be drilled at the same well pad. The regulations and the rdSGEIS need to make it perfectly clear that well pads will be processed through multiple phases on a repetitive basis and the Regulatory Proposals need to account for this fact as well.

Stormwater General Permit for High-Volume Hydraulic Fracturing

Uncontaminated stormwater discharges associated with oil and gas extraction activities are exempt from the federal National Pollutant Discharge Elimination System ("NPDES") program and therefore from New York's SPDES program, as well as under § 402(l)(2) of the Clean Water Act as clarified in § 323 of the Energy Policy Act of 2005. Despite this, the DEC has proposed a new stormwater general permit ("GP") for HVHF in complete disregard of this exemption. To compound this, the DEC's proposal unnecessarily creates requirements unique to the natural gas industry that are far too numerous, unnecessarily prescriptive and lacking the requisite flexibility.

- To acknowledge the exemption, the HVHF GP should reflect New York's current SPDES Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activities (GP-0-06- 002) by requiring the HVHF GP only for "stormwater discharges associated with industrial activity from oil and gas extraction ... which have had a discharge of a reportable quantity (RQ) of oil or a hazardous substance for which notification is required under [federal regulations]."
- Similarly, a statutory NPDES permit exemption applicable to stormwater discharges associated with construction activities remains in effect, even though a federal court overturned EPA regulations implementing it. The DEC should modify the HVHF GP to mirror Pennsylvania's streamlined Erosion and Sediment Control General Permit (ESCGP-1). The Pennsylvania permit requires robust planning for environmental protection along with expedited permit review and authorization.

Bonding for All Wells

The DEC has proposed to amend § 551.7 of the existing regulations to eliminate the maximum bond required for plugging and abandonment of an individual well and a two million dollar cap on bonding for operators that operate multiple wells (i.e., blanket bonding). Although industry supports reasonable bonding requirements, it is unreasonable to eliminate bonding limits and not encourage blanket bonds or other funding mechanisms that will be more cost effective to industry. The DEC needs to keep in mind that shale gas wells are expected to be productive for decades. As such, requiring individual bonding for each well will tie up capital unnecessarily. Bonding is only necessary where an operator defaults on its plugging and abandonment obligations. In recent times, there have been no such defaults. Accordingly, the proposed amendment of § 551.7 goes too far. To the extent that the DEC moves forward with increasing the bonding that is required, operators should be allowed to qualify for guarantees based upon established financial tests utilized in other regulatory programs. Once again, there should be no need to unnecessarily tie up capital in the bonding market for wells that will operate for decades.

Air Issues

With the proposed rdSGEIS, the DEC is seeking to establish statewide regulations and mitigation requirements that conflict with existing and/or proposed EPA air quality regulations pertaining to the same emission sources and are preempted by the Clean Air Act. As recently as August 23, 2011, the EPA proposed new standards specific to the oil and gas sector (sector).[1] The rule proposes regulations based upon proven technologies that would reduce air pollution from the sector while enabling responsible growth in U.S. oil and natural gas production. For the upstream sector, EPA's proposed rule includes wells that are hydraulically fractured (both new wells and workover operations), emissions from storage tanks, pneumatic device fugitive emissions, and some glycol dehydrators. In addition, over the last seven years the EPA has passed new regulations on every type of engine used in the oil and gas industry including diesel-fired, new and reconstructed, and non-road engines.

IOGA has previously submitted a written analysis demonstrating why many of the proposed mitigation requirements are preempted by the Clean Air Act. See also rdSGEIS Comments (Tab 2, Exh. B). Moreover, the DEC's attempt to use SEQRA to impose the proposed air mitigation measures is likewise preempted. Indeed, the New York State Court of Appeals has made it absolutely clear that SEQRA cannot be used to do an "end run" around federal standards in a federally-preempted field. *See Matter of Niagara Mohawk Power Corp.*, 82 N.Y.2d 191, 197-201 (1993); *see also Matter of Power Auth. of State of N.Y. v. Williams*, 60 N.Y.2d 315 (1983).

The DEC's approach in proposing air emissions controls was based upon a worst-case dispersion modeling scenario. While this may provide assurance that the air emissions are controlled in a worst-case scenario, those prescriptive controls should not be required at every location in the state, at every time of day or year, nor at every tank battery regardless of production. To do so would be unnecessary and would greatly over-control most sources.

The new federal engine rules, as well as EPA's proposed rules for oil and natural gas production activities, were or are being developed with extensive input from all affected sectors and are designed to protect the public's health and welfare while allowing reasonable energy development. The DEC has chosen to mandate separate and unique controls, some of which are technically infeasible, not cost-effective, and/or potentially unsafe for certain sources. EPA's rules have provided the State with all the air emission control options necessary to regulate the development of shale gas. The DEC should remove the prescriptive source-specific emissions controls specified in the proposed rdSGEIS and instead rely on the EPA's air emissions control requirements for those same sources both in the current version of the proposed rdSGEIS and when conducting their air emissions permit application reviews.

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[1] EPA, 40 CFR Parts 60 and 63, EPA-HQ-OAR-2010-0505, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, http://www.epa.gov/ttn/atw/oilgas/fr23au11.pdf (accessed August 26, 2011).

Water Withdrawals and Natural Flow Regime Considerations

The proposed rdSGEIS states that a primary emphasis of the DEC is protection of water resources and that water withdrawals affecting surface or groundwater have been identified as a potential impact resulting from use by the natural gas industry for HVHF. While IOGA certainly agrees that protection of water resources is critical, the utilization of the NFR method to calculate passby flows, as proposed by DEC, is misguided, unduly stringent, and contradicts the passby methods employed by the SRBC and DRBC, both of which have regulatory authorities for water withdrawals in their specific jurisdictions. The SRBC and DRBC have been effectively regulating water withdrawals for decades in New York State and the DEC acts as the New York State representative on these commissions. The SRBC has the most experience with the natural gas industry and its methods have been demonstrated to be protective of existing aquatic communities, are designed to be conservative, and incorporate data collected specific to the location of the proposed withdrawal.

It is unreasonable that DEC would impose the NFR method for passby conditions solely for the natural gas industry, when all other withdrawals, such as those by electrical power generating facilities, public water supplies, golf courses and ski resorts, water bottling, manufacturing and industrial sources, would be regulated using the guidance implemented by the appropriate river basin commission. Withdrawals within the Susquehanna and Delaware River Basins should be regulated by the SRBC and DRBC, respectively, to avoid duplication and to ensure regulatory consistency and streamlined approvals. As a result of the water withdrawal legislation adopted into law in New York State this year (Laws of 2011, ch. 401), outside of the Susquehanna and Delaware basins, the DEC would have primacy regarding water withdrawals greater than 100,000 gallons per day. However, that legislation specifically exempts from the permitting requirements withdrawals that are approved by the DRBC or the SRBC. This is current legislative and gubernatorial recognition of the need for the DEC to defer to the federal interstate compact commissions regarding water withdrawals subject to their jurisdiction. The DEC, therefore, should defer to the SRBC passby flow guidance (e.g., SRBC Policy 2003-01), which is environmentally protective and applied uniformly amongst all water users. The DEC, with their membership position within the SRBC and the DRBC, should strive for uniform review standards between itself and the river basin commissions and not seek to override the basin commission standards with standards that are unnecessarily conservative and inconsistent with well-established New York law and policy.

Under the NFR methodology, all withdrawals, including those on large river systems, regardless of withdrawal quantity and rate, would require a passby. While many operators have developed storage capacity and all are utilizing recycled waters, uninterruptible withdrawals with predictable availability are important for year-round operations by the industry. Using the NFR methodology would greatly increase the number of days per year that a water source would be unavailable, when compared with the SRBC passby guidance. Since water withdrawal points would be unusable during much of the year under the NFR methodology, industry will be forced to construct a greater number of water withdrawal locations potentially increasing the overall habitat impact, and likely reducing the opportunities to share sources among operators.

Additionally, industry may need to purchase additional waters or augment their existing supplies from older and larger public water supplies in New York State. Many of these public water supply systems commanded very large water withdrawals in the past to support now defunct industries. Due to the age of those historic withdrawals, these sources may not have undergone the rigorous environmental review currently employed by the SRBC; instead these withdrawals are grandfathered under the SRBC regulation. Purchasing water from public water supplies also will increase permitting and transportation costs to the industry.

The NFR methodology is overly complicated, will be difficult and costly to implement and appears to be administratively burdensome on both the industry and the regulatory agency. Metering and monitoring requirements themselves are projected to exceed an additional $200,000 per withdrawal location, with no demonstrated environmental benefits over the passby flow guidance conditions implemented by SRBC under Policy 2003-01.

Moreover, the NFR methodology being proposed by the DEC does not take into account the statutory obligation to balance competing water resources as required by ECL § 15-0105 and the cases interpreting the balancing obligations of the DEC regarding water consumption and use. The unnecessarily conservative NFR methodology conflicts with this statutory obligation.

All of the concerns expressed by DEC in the proposed rdSGEIS regarding potential water withdrawal impacts, including reduced stream flow, impacts to aquatic habitats and ecosystems, impacts to wetlands, and aquifer depletion, are addressed by the river basin commissions through their extensive water withdrawal regulatory programs. In the proposed rdSGEIS, the DEC itself recognizes that the amount of water withdrawn specifically for HVHF is projected to be low compared to overall water use in New York State, increasing fresh water demand by only 0.24%. In light of this small increase in projected water use and the existing authorities operating in New York State, this proposed duplicative effort is unwarranted. The programs implemented by SRBC and DRBC are environmentally protective, robust, and should be utilized by DEC for regulating withdrawals by the natural gas industry. Outside of the jurisdictional areas of the SRBC and the DRBC, reasonable standards should be employed in accordance with the balancing requirements of the ECL that promote the development of the resource and protect the environment.

Transportation Plans

The rdSGEIS's proposed mitigation measures for road impacts raise significant concerns. ECL § 23-0303(2) gives primary jurisdiction over roads to local municipalities and, as such, the rdSGEIS states that the DEC will include as a supplemental permit condition that the issuance of a well permit does not relieve an operator from compliance with local regulation. *See* rdSGEIS, § 7.11.3. And, to this point, the rdSGEIS strongly encourages operators to enter into road use agreements with impacted local municipalities and requires operators to file copies of their road use agreements with the DEC. rdSGEIS, §§ 7.11.3, 8.1.1.4. Such a road use agreement should comprise all of the required mitigation.

Unfortunately, the rdSGEIS goes on to require submission of a transportation plan, which will be incorporated by reference into the drilling permit. rdSGEIS, §§ 7.11.1.1; 7.11.1.3. The required transportation plan must be prepared by a NYS-licensed professional engineer in consultation with the DEC. rdSGEIS, § 7.11.1.3. It must include, among other things, the number of anticipated truck trips, times of day when trucks will be operating, proposed haul routes, the locations of, and access to and from, parking/staging areas and the ability of the roads proposed in the haul route to accommodate the anticipated traffic. rdSGEIS, §§ 7.11.1.1; 7.11.1.3. All of this is duplicative and unnecessary where an operator has entered into a road use agreement. The submission of a road use agreement, therefore, should obviate any requirement for a transportation plan.

The transportation plan also must include a baseline survey of all roads, bridges and culverts according to the NYSDOT 2010 Network Level Pavement Condition Assessment Manual. rdSGEIS, § 7.11.1. Given the desire that the SGEIS will have a lengthy useful lifespan, it is inappropriate to articulate the manner in which an operator shall assess baseline road conditions which will change over time and vary in different road use agreements. The requirement also detracts from local jurisdiction over roads by taking away the right of operators and local municipalities to determine the appropriate manner in which to document baseline conditions.

Also problematic is the requirement that an operator submit a copy of its road use agreement and transportation plan to the NYSDOT and the expectation that the NYSDOT will have an advisory role with respect to both. rdSGEIS, § 7.11.1.3; 8.1.2.2. First, there is no need for the NYSDOT to review and comment on an operator's road use agreement with a municipality. That is an issue appropriately left to the signatories of the agreement. Second, the rdSGEIS is silent as to the scope and extent of the NYSDOT's role and the timing associated with its review. This creates permitting uncertainty for operators and, more than likely, unnecessary delay in permitting. It also creates unnecessary regulatory cost in a time when New York State needs to streamline government, not expand it.

"Green" Frac Fluid Analysis

During the time that the DEC has been evaluating environmental impacts associated with HVHF, considerable progress has been made with the industry "greening" the hydraulic fracturing process. Several years ago, it was not uncommon to see as many as 20 chemical additives being used in an effort to improve the efficacy of the stimulation technique. Today, many operators are using as few as 6 chemical additives and have reduced the volumes of additives without compromising efficacy. Notwithstanding the significant process, the rdSGEIS and the proposed regulations require as part of *each* permit application a review and certification by the operator that the operator is using hydraulic fracturing additives that are the least toxic alternatives available. Although this requirement attempts to qualify the analysis requiring efficacy, the language is confusing and is not always consistent among the rdSGEIS and the various places where this requirement appears in the draft regulations. Initially, it is important to stress that all decisions concerning the makeup of hydraulic fracturing fluid are based upon an engineering evaluation that alters the additive mix to maximize the efficacy of the hydraulic fracturing process within the target formation. Very often, adjustments are made in the field based upon data obtained during the hydraulic fracturing process. Given the great progress that has been made by the industry without compromising efficacy, there is no need to mandate this type of analysis.

Alternatively, if an analysis of "green" frac fluid additives is required, each service company proposing to conduct HVHF business in New York should be required to conduct an initial analysis, subject the requirement that the DEC can request an updated analysis if circumstances have changed. The analysis would focus on the relative toxicity and other environmental attributes of the various additives that are used, or could be used, by a service company in hydraulically fracturing Marcellus Shale wells or wells in other shale gas plays. The service company would include in the review any "green" products it offers that could be used in shale gas wells. The service company could subsequently update its master list when it anticipates using a new chemical, or every two years at a minimum.

MARCELLUS SHALE HYDRAULIC FRACTURING

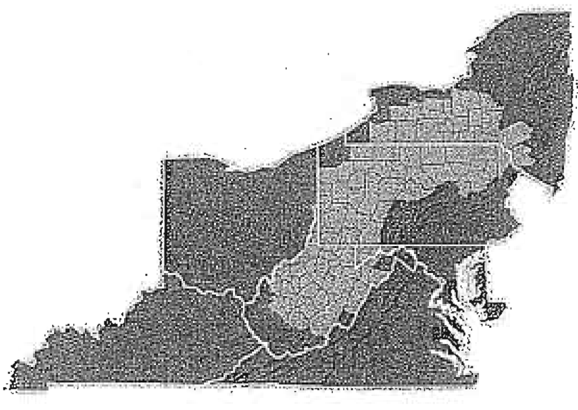
FACT SHEET

JULY 2010

Hydraulic fracturing is a proven technological advancement which allows natural gas producers to safely recover natural gas from deep shale formations. This discovery has the potential to not only dramatically reduce our reliance on foreign fuel imports, but also to significantly reduce our national carbon dioxide (CO_2) emissions and to accelerate our transition to a carbon-light environment. Simply put, deep shale gas formation development is critical to America's energy needs and its economic renewal.

Experts have known for years that natural gas deposits existed in deep shale formations, but until recently the vast quantities of natural gas in these formations were not thought to be recoverable. Today, through the use of hydraulic fracturing, combined with sophisticated horizontal drilling, extraordinary amounts of natural gas from deep shale formations across the United States are being safely produced.

Hydraulic fracturing has been used by the oil and gas industry since the 1940s and has become a key element of natural gas development worldwide. In fact, this process is used in nearly all natural gas wells drilled in the United States today. Properly conducted modern hydraulic fracturing is a highly engineered, controlled, sophisticated and safe procedure.



Chesapeake's operating areas in the Marcellus Shale

KEY POINTS

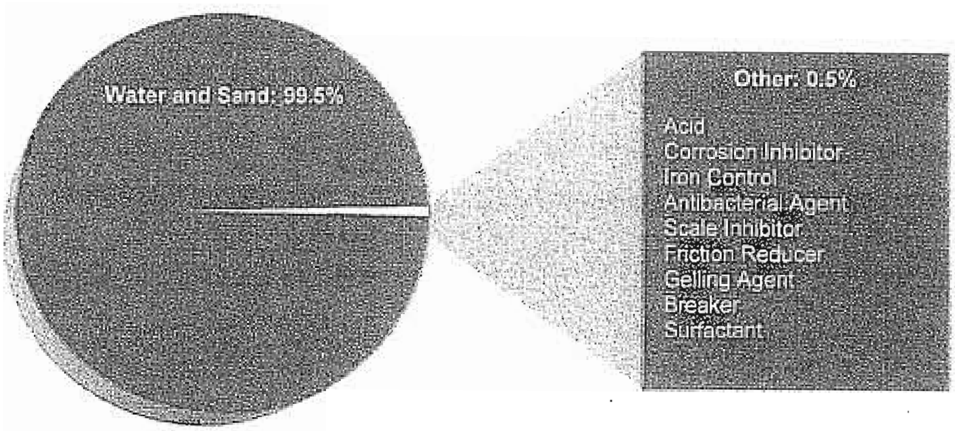
- Hydraulic fracturing is essential for the production of natural gas from shale formations.
- Fracturing fluids are comprised of approximately 99.5% water and sand and are handled in self-contained systems.
- Freshwater aquifers are protected by multiple layers of protective steel casing surrounded by cement; this is administered and enforced under state regulations.
- Deep shale gas formations exist many thousands of feet underground.

What is hydraulic fracturing?

Hydraulic fracturing, commonly referred to as fracing, is the process of creating fissures, or fractures, in underground formations to allow natural gas to flow. In the Marcellus Shale, Chesapeake Energy pumps water, sand and other additives under high pressure into the formation to create fractures. The fluid is approximately 99.5% water and sand, along with a small amount of special-purpose additives. The newly created fractures are "propped" open by the sand, which allows the natural gas to flow into the wellbore and be collected at the surface. Normally a hydraulic fracturing operation is only performed once in the life of a well. Variables such as surrounding rock formations and thickness of the targeted shale formation are studied by scientists before hydraulic fracturing is conducted. The result is a highly sophisticated process that optimizes the network of fractures and keeps them safely contained within the boundaries of the deep shale gas formation.

Fracturing Fluid Makeup

In addition to water and sand, other additives are used to allow hydraulic fracturing to be performed in a safe and effective manner. Additives used in hydraulic fracturing fluids include a number of compounds found in common consumer products.



Example of Typical Marcellus Shale Fracturing Fluid Makeup

A representation showing the percent by volume of typical Marcellus Shale hydraulic fracturing fluid components (see graphic) reveals that approximately 99.5% of the fracturing fluid is comprised of water and sand. This fluid is injected into deep shale gas formations and is typically confined by many thousands of feet of rock layers.

Product	Purpose	Downhole Result	Other Common Uses
Water and Sand: ~ 99.5%			
Water	Expand fracture and deliver sand	Some stays in formation while remainder returns with natural formation water as "produced water" (actual amounts returned vary from well to well)	Landscaping, manufacturing
Sand (Proppant)	Allows the fractures to remain open so the gas can escape	Stays in formation, embedded in fractures (used to "prop" fractures open)	Drinking water filtration, play sand, concrete and brick mortar
Other Additives: ~ 0.5%			
Acid	Helps dissolve minerals and initiate cracks in the rock	Reacts with minerals present in the formation to create salts, water, and carbon dioxide (neutralized)	Swimming pool chemical and cleaner
Corrosion Inhibitor	Prevents the corrosion of the pipe	Bonds to metal surfaces (pipe) downhole. Any remaining product not bonded is broken down by micro-organisms and consumed or returned in produced water.	Used in pharmaceuticals, acrylic fibers and plastics
Iron Control	Prevents precipitation of metal (in pipe)	Reacts with minerals in the formation to create simple salts, carbon dioxide and water all of which are returned in produced water	Food additive; food and beverages; lemon juice
Anti-Bacterial Agent	Eliminates bacteria in the water that produces corrosive by-products	Reacts with micro-organisms that may be present in the treatment fluid and formation. These micro-organisms break down the product with a small amount of the product returning in produced water.	Disinfectant; sterilizer for medical and dental equipment
Scale Inhibitor	Prevents scale deposits downhole and in surface equipment	Product attaches to the formation downhole. The majority of product returns with produced water while remaining reacts with micro-organisms that break down and consume the product.	Used in household cleansers, de-icer, paints, and caulk
Friction Reducer	"Slicks" the water to minimize friction	Remains in the formation where temperature and exposure to the "breaker" allows it to be broken down and consumed by naturally occurring micro-organisms. A small amount returns with produced water.	Used in cosmetics including hair, make-up, nail and skin products
Surfactant	Used to increase the viscosity of the fracture fluid	Generally returned with produced water, but in some formations may enter the gas stream and return in the produced natural gas	Used in glass cleaner, multi-surface cleansers, antiperspirant, deodorants and hair-color
Gelling Agent	Thickens the water in order to suspend the sand	Combines with the "breaker" in the formation thus making it much easier for the fluid to flow to the borehole and return in produced water	Cosmetics, baked goods, ice cream, toothpaste, sauces, and salad dressings
Breaker	Allows a delayed break down the gel	Reacts with the "crosslinker" and "gel" once in the formation making it easier for the fluid to flow to the borehole. Reaction produces ammonia and sulfate salts which are returned in produced water.	Used in hair coloring, as a disinfectant, and in the manufacture of common household plastics

Hydraulic Fracturing and Groundwater Protection

Unlike shallow natural gas projects, such as shallow coal bed methane (CBM), the producible portions of deep shale gas formations exist many thousands of feet below the surface. The productive area of the Marcellus Shale is found at depths ranging from 4,000 to 8,500 feet underground; and the average depth of a Chesapeake natural gas well in the Marcellus Shale is more than 5,300 feet. Chesapeake does not conduct any production or fracturing activities in fresh groundwater aquifers. In fact, across Chesapeake's Marcellus Shale operations, groundwater aquifers and producing natural gas formations are separated by thousands of feet of protective rock barriers.

How deep is 5,300 feet?

- More than **four Empire State Buildings** stacked end to end
- As deep as the deepest part of the **Grand Canyon**
- More than **17 football fields** laid out goal line to goal line

State oil and gas regulatory programs place great emphasis on protecting groundwater. Current well construction requirements consist of installing multiple layers of protective steel casing surrounded by cement that is specifically designed and installed to protect freshwater aquifers.

The measures required by state regulatory agencies in the exploration and production of deep shale gas formations have been very effective in protecting drinking water aquifers from contamination attributable to hydraulic fracturing. Based on reviews of state oil and gas agencies, there has not been a documented case of drinking water aquifer contamination related to hydraulic fracturing of a deep shale gas well.

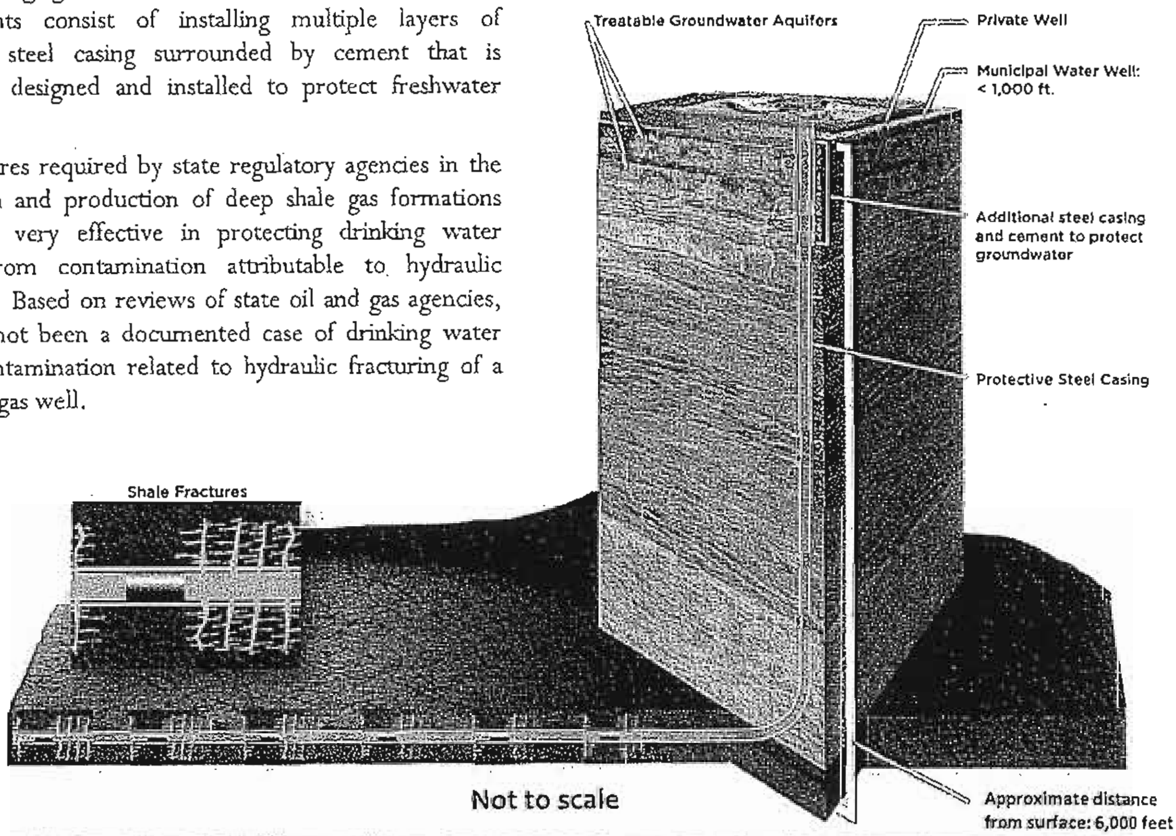
Furthermore, the Groundwater Protection Council issued a report in April of 2009 stating that the potential for hydraulic fracturing in deep shale gas wells to impact groundwater is extremely remote, as low as one in 200 million.

Information Sources

- United States Department of Energy
- Ground Water Protection Council
- Dr. Michael Economides

About Chesapeake

Chesapeake Energy Corporation is one of the largest producers of natural gas and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Fayetteville, Haynesville, Marcellus and Bossier natural gas shale plays and in the Eagle Ford, Granite Wash and various other unconventional oil plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. Further information is available at www.chk.com.



AIR EMISSIONS AND REGULATIONS

FACT SHEET

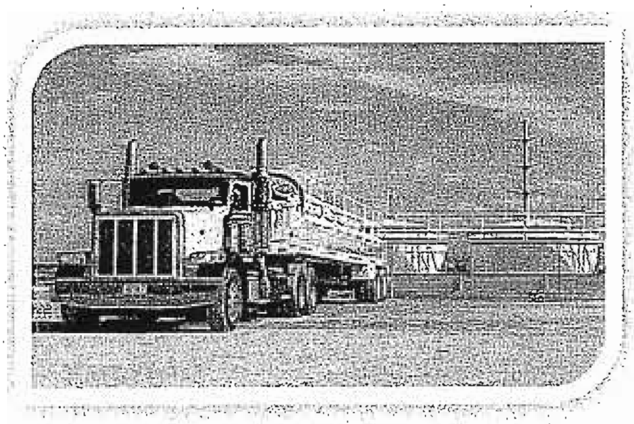
JULY 2010

Introduction

Air pollutants are emitted into the atmosphere anytime one drives to work, rides a train, mows the lawn or grills outdoors. Similar types of air pollutants are emitted from natural gas production activities such as drilling and hydraulic fracturing, completion/production activities, gas treatment/compression, gas gathering and gas processing. Importantly, all sources of air emissions in the natural gas industry are subject to strict regulations written by the Environmental Protection Agency (EPA) under the authority of the federal Clean Air Act (CAA). States effectively implement these federal regulations, and in many cases, state and local governments place additional restrictions on air emissions resulting from natural gas production activities.

Drilling and Hydraulic Fracturing

Modern drilling and hydraulic fracturing is typically accomplished with the use of diesel engines. The emissions from these diesel engines are regulated by standards established by the EPA in the same manner that it regulates emissions from cars and trucks. Manufacturers of these engines are required to meet standards which are progressively more stringent for newer engines than those manufactured years ago. As a result of these more stringent requirements, emissions from new diesel engines have been reduced by approximately 75% during the past decade and will be reduced another 90% from today's standards in the next five to six years. [1,2]



KEY POINTS

- All sources of air emissions in the natural gas industry are subject to strict regulations written by the Environmental Protection Agency (EPA) under the authority of the federal Clean Air Act (CAA).
- States effectively implement these federal regulations.
- In many cases, states and local governments place additional restrictions on air emissions resulting from natural gas production activities.

Completion/Production Activities

Virtually all natural gas wells drilled today must be hydraulically fractured during completion in order to economically produce this premium, clean-burning fuel. This is particularly the case in tight reservoirs, such as deep shale. After the hydraulic fracture process is completed, fracturing fluids, which are comprised of more than 99% water and sand, are allowed to flow back to the surface for recovery. This is often referred to as "cleaning up the well." The flowback period can last for hours or for several days. Some natural gas flows back with the fracturing fluid, and this gas may contain volatile organic compounds (VOCs) such as propane. Each state has adopted state implementation plans (SIPs) that are approved by the EPA to ensure that minor and temporary sources of VOC emissions, such as well completions, do not cause or contribute to violations of federal air quality standards for ozone.[3]

In addition to these regulations, Chesapeake controls or reduces VOC emissions through a voluntary procedure called "reduced emission completions" or "green completions."

A reduced emission completion can eliminate most of the VOC emissions and recover valuable natural gas during flowback and well testing.[4] One drawback of reduced emission completions is that it is not available for every well that is drilled and completed. A reduced emission completion requires special equipment and the installation of a natural gas gathering line and sales meter prior to well flowback and testing, which is not possible on all wells.

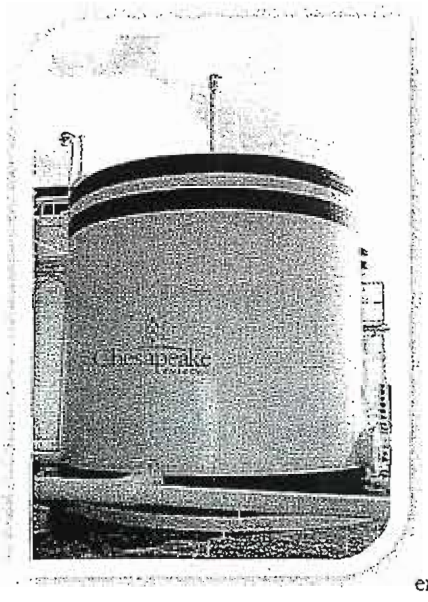
A typical natural gas wellsite may have a two-phase separator that is used to separate produced water from natural gas. In that case, the produced water is stored on-site until removed by truck and little, if any, VOC is emitted from the stored water. When wells produce natural gas that is "richer" (contains heavier hydrocarbons, such as propane, butanes, pentanes, etc.), the wellsite may have a three-phase separator called a "heater treater," which separates produced water, oil/condensate and natural gas. In this case, the oil/condensate is also stored on-site until removed by truck.

VOC may be emitted from storage tanks that store the oil/condensate and vent to the atmosphere. Each state has rules that determine how much VOC may be emitted before an air quality permit is required and/or before equipment such as a flare or other emissions control device, such as a vapor recovery unit (VRU), must be used to control emissions of VOC. Chesapeake prefers to control emissions of VOC with a VRU in order to reduce emissions and recover valuable natural gas.[5]

Gas Treatment/Compression

Many wellsites have a small tri-ethylene glycol dehydrator unit, which is equipment that removes water from the natural gas in order to meet gas pipeline specifications. These units are subject to very stringent EPA regulations known as National Emissions Standards for Hazardous Air Pollutants (NESHAP). Potential emissions of hazardous air pollutants, such as benzene, must be very low or equipment must be added to control these emissions.[6]

Occasionally, a natural gas well will require a small wellhead gas compressor to raise the gas pressure to the gas gathering line's required pressure. These compressors are typically powered by natural gas-fired engines. The engines on these compressors are subject to EPA regulations known as New Source Performance Standards (NSPS) which limit the amount of NO_X and VOC that can be emitted.[7] The engines are also subject to strict EPA NESHAP regulations to control emissions of hazardous air pollutants such as formaldehyde.[8]



Gas Gathering

Gas gathering is a process by which natural gas produced from multiple wells is gathered into a pipeline system that transports it to a gas compressor station and allows the produced gas to be marketed. A compressor station consists of one or more large compressors that boost the pressure of natural gas so that it can flow to a user or a local distribution company, such as your local natural gas utility company. The natural gas-fired engines that drive these compressors are subject to the same EPA regulations previously discussed.[7,8]

Many states have additional emission standards for these large engines. For instance, in the Dallas Fort-Worth Nonattainment Area, which covers nine counties in North-central Texas, natural gas-fired compressor engines are subject to an emissions standard for NO_X that is four times as stringent as the current EPA NSPS regulation.[9]

Dehydration units may also be located at compressor stations. These are subject to the EPA regulations previously discussed.[6] Any hydrocarbon liquids that condense after the gas is compressed to higher pressures and cooled are separated and may be stored in tanks that vent to the atmosphere. Potential emissions of VOC from these tanks are subject to various state limits as previously discussed.

Gas Processing

After dehydration, natural gas that is "lean" (containing little, if any, heavier hydrocarbons such as propane, butanes, pentanes, etc.) will typically go straight to large gas transmission lines to be transported to markets. However, natural gas that is "rich" will typically be processed to condense and remove the heavier hydrocarbons known as natural gas liquids (NGL). These liquids include ethane, propane, butanes, pentanes and natural gasoline. The NGL is stored on-site in pressurized tanks and then shipped off-site via pipeline or tanker truck.

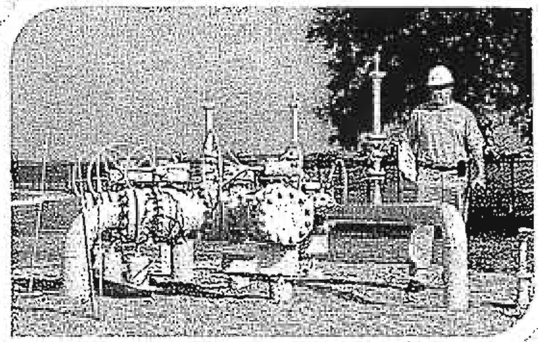
VOC can be emitted from pumps, fittings, flanges and other connectors used in gas processing plants. Therefore, this equipment is subject to a stringent EPA NSPS regulation that requires the facility operator to implement a leak detection and repair program.[10] A gas processing plant may also have natural gas-fired engines that drive refrigeration compressors, inlet gas compressors or outlet gas compressors. These engines are subject to the EPA NSPS and NESHAP regulations previously discussed.[7,8]

Summary

Activity	Regulation	Goal	Control Method(s)
Drilling	Engine emissions standards	Limit emissions of NO_X, PM and SO_2	Manufacturer's technology/diesel fuel sulfur standards
Hydraulic Fracturing	Engine emissions standards	Limit emissions of NO_X, PM and SO_2	Manufacturer's technology/diesel fuel sulfur standards
Completion/Production Activities	State rules under state implementation plans (SIPs)	Limit emissions of VOC	Limited venting, use of flares, "green completions"
Gas Treatment	NESHAP for TEG Units	Limit emissions of HAP	Condensers, flares, VRUs
Gas Compression	NESHAP and NSPS for compressor engines	Limit emissions of NO_X, VOC and HAP	Low emission engine technologies, catalysts on engine exhaust
Gas Processing	NSPS for fugitive emissions	Limit emissions of VOC	Leak Detection and Repair (LDAR) Program

Information Sources

1. 40 CFR Part 89 – Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines.
2. 40 CFR Part 80 – Highway and Nonroad Diesel Regulations.
3. 40 CFR Part 50 – National Primary and Secondary Ambient Air Quality Standards.
4. http://www.epa.gov/gasstar/ (see Green Completions – PRO Fact Sheet No. 703).
5. http://www.epa.gov/gasstar/ (see Lessons Learned – Installing Vapor Recovery Units on Crude Oil Storage Tanks).
6. 40 CFR Part 63, Subpart HH – National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.
7. 40 CFR Part 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
8. 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.
9. 30 TAC Chapter 117, Subchapter D - 117.2100(a).
10. 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.



About Chesapeake

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EMERGENCY RESPONSE

FACT SHEET JULY 2010

Chesapeake Energy Corporation (Chesapeake) promotes public safety, environmental protection and public understanding of our operations in the communities where we operate. Chesapeake values these communities and takes the responsibility of operating in a socially responsible manner very seriously. Our efforts to accomplish this include, but are not limited to:

- Maintaining an Emergency Response Plan (ERP)
- Submitting chemical information to local responders, local emergency planning committees and the states in which we operate
- Providing training to local emergency responders on our ERP
- Conducting environmental and safety training to provide safe and environmentally responsible working operations for employees and the public
- Using signs and labels to identify our drilling locations and production sites
- Posting 24-hour emergency contact information on our signage located at the entries to our locations and sites
- Posting hazard identification at the gates to and on our locations
- Appropriately fencing our locations
- Implementing and maintaining spill prevention measures on our locations
- Incorporating storm water runoff best management practices

Design and Preventive Maintenance

Equipment utilized by Chesapeake is built to specific industry standards. Preventive maintenance and routine inspections are conducted to ensure that equipment is maintained and operating correctly. In addition, Chesapeake routinely reviews its work practices to ensure efficiency and safety. Together, these proactive measures allow us to incorporate environmentally sound, safe work practices into our daily operations to prevent emergencies.

KEY POINTS

- Environmentally sound, safe work practices are incorporated into our daily operations
- In the event of an emergency, Chesapeake will activate an immediate and organized response
- During an emergency response, our main objective is to protect the public, our employees and the environment.

Technology evolves constantly, and Chesapeake prides itself on the ability to utilize these advancements to maintain a safe environment from drilling the well to natural gas transmission. A blowout preventer, used during drilling to protect against unexpected high pressures underground, is one example. We also utilize automatic emergency shut offs at some of our production locations. When installing pipelines, x-rays are taken on-site to ensure the integrity of the welds. Next, the pipeline is filled with water and hydrostatically tested to one and a half times the highest operating pressure the line will ever achieve This ensures the integrity of all components of the pipeline prior to being put into service.

Furthermore, Chesapeake exceeds government regulations for well operations requiring spill prevention plans. We conducted research to identify the most stringent regulatory standards for secondary containment (spill containment) in all areas where we operate, and made those our standard. The secondary containment requirement at locations triggering spill prevention plans is one and a half times the volume of the largest container (tank).

A Record of Safety

Chesapeake has a proven record of safety. For example, the company is entrusted with executing the largest drilling program ever accomplished at a major international airport, the Dallas/Fort Worth (DFW) International Airport. Drilling and completing the wells on the DFW site is done under the scrutiny of airport security officials, the Federal Aviation Administration (FAA), the airport board, regulatory agencies and numerous environmental and safety interest groups.

Emergency Response

Although rare, situations can occur which require an immediate, organized and focused response by Chesapeake. To prepare for and respond to these situations on our locations, Chesapeake has developed a single, comprehensive approach to emergency management. The objective of our emergency response efforts is to ensure that all levels of the company have the capability to work together efficiently and effectively. To achieve this objective, we employ the same emergency response structure used by first responders, the Incident Command System. By working as a team with emergency response contractors and local first responders, such as the fire department, we are able to respond quickly and efficiently with one main objective: protect the public, our employees and the environment.

The ERP is built on the following principles:

- Well trained personnel
- Engaged partnerships with local responders and professional emergency response contractors
- Tiered response designed to respond to every incident ranging from small to large
- Scalable, flexible and adaptable operational capabilities
- Unified incident command

How will Chesapeake respond to an emergency?

In the event of an emergency, an immediate and organized response by Chesapeake will be activated. Our ERP establishes the framework and response guidelines for designated Chesapeake employees based on the type and nature of the incident. The ERP outlines procedures for handling emergencies to minimize adverse impacts on the public, our employees and the communities where we operate. The first priority during an emergency is the safety of the responders and the public involved, followed by the environment and property. All levels of the Chesapeake organization work together to plan and prepare for emergencies. Several examples of the measures we take include:

- Training our employees in their roles during emergency response
- Establishing partnerships with professional, experienced emergency response contractors
- Training local emergency responders, such as fire departments, on our ERP
- Educating local responders on the type of equipment, chemicals and associated hazards present on our locations
- Conducting regularly scheduled meetings with our contractors to discuss environmental, health and safety issues, including emergency planning
- Conducting emergency response drills with employees, contractors and local responders to ensure the effectiveness of the ERP

Community safety and efficient emergency response take a coordinated team effort, which includes our employees, third party contractors and local first responders. Chesapeake has identified the necessary local emergency response team members within the communities where we operate and established a relationship with them that has created an ongoing state of readiness to respond, should the need arise.

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GREENHOUSE GAS EMISSIONS AND REDUCTIONS

Chesapeake ENERGY

FACT SHEET | JULY 2010

What are Greenhouse Gases?

Greenhouse gases such as water vapor, carbon dioxide, methane and nitrous oxide are gases that prevent heat from escaping into the atmosphere, somewhat like the glass panels of a greenhouse. Greenhouse gases are necessary to sustaining life because they keep the planet's surface temperature relatively stable. Many scientists believe that the burning of fossil fuels such as coal, oil and natural gas, along with deforestation have caused the concentrations of these heat trapping greenhouse gases (mostly carbon dioxide) to increase in our atmosphere. Some scientists also believe that the increased atmospheric concentrations are a primary cause of higher global temperatures.[1]

Each greenhouse gas has been assigned a number that reflects its global warming potential (GWP). For instance, carbon dioxide has a GWP of 1, methane has a GWP of 23 and nitrous oxide has a GWP of 296.[2] This comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as carbon dioxide equivalents (CO_2e).

Fossil fuels are combusted in order to provide different types of energy (heat, electricity, etc.). Comparing the combustion of natural gas to the combustion of coal and oil, natural gas emits 44% less carbon dioxide than coal, and 25% to 30% less than oil.

Comparison of Carbon Dioxide Emissions from Combustion of Fossil Fuels

Fuel Source	Natural Gas	Oil	Coal
Carbon Dioxide Emitted	117,000*	164,000*	208,000*

*Pounds of emissions produced per billion BTU of energy

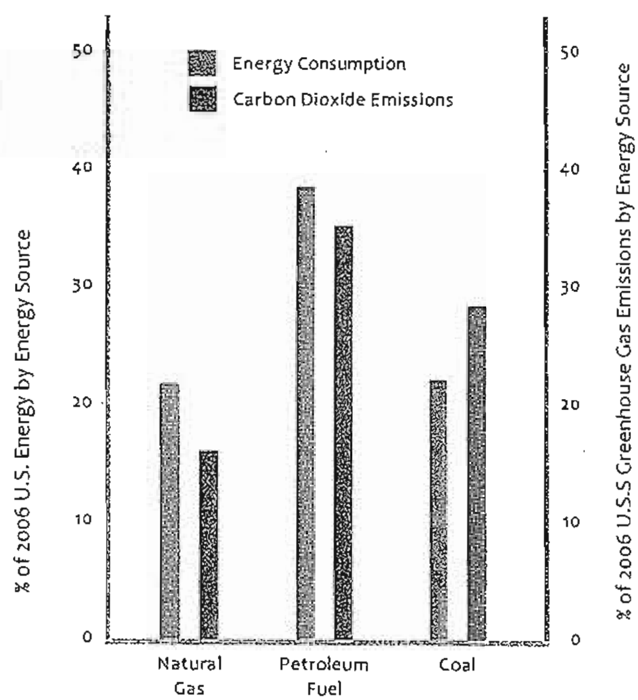
Source: Energy Information Administration

In 2006, the total U.S. greenhouse gas emissions were 7,050 million metric tons of CO_2e ($MMTCO_2e$).[3] Only 16% of the 2006 U.S. greenhouse gas emissions came from the combustion of natural gas (mostly electrical power production, home heating and industrial use) which accounted for 22% of the 2006 U.S. energy consumption. The following graph compares the share of total U.S. energy consumption versus the share of total U.S. CO_2e emissions generated in 2006 from the combustion of coal, petroleum fuels and natural gas.[3]

KEY POINTS

- Combustion of natural gas provides 22% of the nation's energy, but only 16% of its greenhouse gas emissions.
- The U.S. natural gas industry accounts for only 3.2% of total U.S. greenhouse gas emissions on a CO_2-equivalent basis.
- Chesapeake's greenhouse gas emissions come mainly from internal combustion engines that emit CO_2 and from fugitive emissions of methane.
- Chesapeake has partnered with the EPA in a voluntary program to reduce methane emissions.

Carbon Dioxide Emissions vs. Energy Consumption



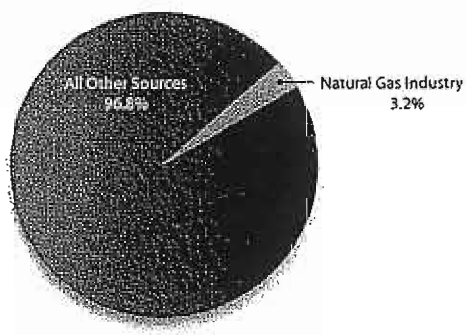
Are Any Greenhouse Gases Emitted from Chesapeake's Operations?

As with almost all industries, greenhouse gases are emitted from Chesapeake Energy Corporation's (Chesapeake's) operations. Our greenhouse gas emissions come mainly from the use of internal combustion engines that emit CO_2 and from fugitive emissions of methane.

However, the entire U.S. natural gas industry only accounts for approximately 3.2% of the country's total greenhouse gas emissions on a CO_2-equivalent basis.[4] This industry consists of hundreds of companies in addition to Chesapeake, providing services that include production, processing, transmission and storage and distribution to users.

Are Greenhouse Gas Emissions Regulated?

Greenhouse gas emissions are not regulated in the United States, with one exception: the Regional Greenhouse Gas Initiative. This initiative operates a cap-and-trade program for CO_2 emissions from electric power plants located in a group of states in the northeastern part of the United States. California has passed legislation and is also beginning to regulate greenhouse gas emissions from industrial and transportation sources in California.



Total U.S. Greenhouse Gas Emissions[4]

What is Chesapeake Doing to Reduce Greenhouse Gas Emissions?

Chesapeake does not presently operate in jurisdictions that regulate greenhouse gas emissions. However, the company has joined with the Environmental Protection Agency (EPA) in a voluntary program to reduce methane emissions where feasible. Established in 1993, the EPA's Natural Gas STAR Program is focused on sharing technical ideas and methodologies for Best Management Practices (BMPs) with member companies that reduce methane emissions.[5] The program promotes technology-sharing workshops between member companies, such as a May 2009 EPA Natural Gas STAR Workshop hosted by Chesapeake in Oklahoma City. The program is also a means for member companies to record and report emissions reductions to the EPA. Many of the BMPs promoted by the STAR Program have historically been utilized by Chesapeake. However, becoming a member of the program has placed additional focus on our efforts to voluntarily reduce methane emissions. Some of the BMPs that Chesapeake has focused on since joining the program include:

- Reduced Emission Completions (often referred to as "green completions")
- Low-bleed pneumatic controllers
- Flash gas compression
- Enhanced compressor blow-down procedures
- Vapor recovery units
- Dehydrator flash tanks
- Fugitive leak detection and repair

Information on these and other BMPs can be found at http://www.epa.gov/gasstar/.

The EPA reports that 2007 was a very successful year for the now world-wide **Natural Gas Star Program** with reported reductions of approximately 92.5 billion cubic feet (Bcf) of natural gas (methane). This amounts to an avoidance of greenhouse gas of 2.7 $MMTCO_2e$. Approximately 72% of those reductions were in the U.S.

Information Sources

1. US EPA Climate Change website: http://www.epa.gov/climatechange.basicinfo.html
2. IPCC Third Assessment Report: Climate Change 2001.
3. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006 (April 2008) USEPA #430-R-08-005.
4. Coverage of Natural Gas Emissions and Flows under a Greenhouse Gas Cap-and-Trade Program; ICF International, for the Pew Center on Global Climate Change.
5. US EPA Natural Gas STAR Program website: http://www.epa.gov/gasstar/

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WATER USE IN MARCELLUS DEEP SHALE GAS EXPLORATION

FACT SHEET

JULY 2010

How much water is used in Marcellus deep shale gas development?

Water is an essential component of Chesapeake Energy's (Chesapeake) deep shale gas development. Chesapeake uses water for drilling, where a mixture of clay and water is used to carry rock cuttings to the surface, as well as to cool and lubricate the drillbit. Drilling a typical Chesapeake Marcellus deep shale gas well requires approximately 100,000 gallons of water.

Water is also used in hydraulic fracturing, where a mixture of water and sand is injected into the deep shale at a high pressure to create small cracks in the rock and allow gas to freely flow to the surface. Hydraulically fracturing a typical Chesapeake Marcellus horizontal deep shale gas well requires an average of five and a half million gallons per well.

How does Marcellus deep shale gas water use compare to regional uses?

The volume of water necessary to drill and fracture Marcellus deep shale gas wells represents a very small percentage of the total water resources used in the Marcellus geographic region. This region generally includes central and western Pennsylvania, southern New York and northern West Virginia. The total water use in the Marcellus Shale area in 2000 was approximately 3.6 trillion gallons. The natural gas industry is expected to increase the amount used by less than 0.1%, and is well within available resources in the region. Again, this volume is very small in terms of the overall water budget for this region. The largest water users in the Marcellus Shale geographic area are power generation (approximately 72%), industry and mining (approximately 16%), and municipal/public water supply (approximately 12%). Agricultural water use accounts for only one-tenth of one percent in this area (0.10%). Water used in Chesapeake Marcellus deep shale gas differs most notably from all other uses because it is temporary, occurring only once during the drilling and completion phases of each well. Use of this water does not represent a long-term commitment of the resource in the Marcellus Shale geographic area.

How much is 5.6 million gallons?

The 5.6 million gallons of water needed to drill and fracture a Marcellus deep shale gas well is equivalent to the amount of water consumed by:

- New York City in eight minutes
- A 1,000 megawatt coal-fired power plant in 13 hours
- A golf course in 28 days
- Nine acres of corn in a season

While these represent continuing consumption, the water used for a shale gas well is a one-time use.

KEY POINTS

- Water resources are protected through stringent state, regional and local permitting processes.
- Natural gas production uses significantly less water per BTU of energy produced than other fuel sources such as coal, oil or ethanol.
- Water is essential for Marcellus deep shale gas development.
- Marcellus deep shale gas drilling and hydraulic fracturing uses a small amount of water compared to other uses within the geographic area.

How much water is used in Marcellus deep shale gas development compared with other energy sources?

Water and energy are interdependent. Water is essential to energy resource development. Conversely, energy resources are needed for producing, processing, distributing and using water resources. A typical Marcellus deep shale gas well will produce approximately 4.2 Bcf (billion cubic feet) of gas over its lifetime, the amount of water used to produce the gas equates to about 1.3 gallons for every million British thermal unit (MMBTU - one MMBTU equals about a thousand cubic feet of gas). To put this in perspective, this is approximately 15% of the water needed to produce one MMBTU of coal that is ready to burn in a power plant or 0.05% of the water needed to produce the same energy equivalent of ethanol for fuel. The table on the following page compares water use per unit of energy for several energy sources.

Water requirements for various energy resources

Energy Resource	Range of Gallons of Water Used per MMBTU of Energy Produced
Marcellus Shale Natural Gas[1]	1.30 [2]
Coal (no slurry transport) Coal (with slurry transport)	2 – 8 13 – 32
Nuclear (uranium ready to use in a power plant)	8 – 14
Conventional Oil	8 – 20
Synfuel - Coal Gasification	11 – 26
Oil Shale	22 – 56
Tar Sands	27 – 68
Synfuel - Fisher Tropsch (from coal)	41 – 60
Enhanced Oil Recovery (EOR)	21 – 2,500
Biofuels (Irrigated Corn Ethanol, Irrigated Soy Biodiesel)	> 2,500

[1]Source: GWPC Report
[2]The transport of natural gas can add between zero and two gallons per MMBTU.
Other Sources: DOE

Where does the water come from?

Chesapeake utilizes a variety of sources of water in Marcellus deep shale gas exploration. The sources include rivers, creeks and lakes. Chesapeake is also reviewing the use of a variety of other water resources such as discharge water from industrial or city wastewater treatment plants, groundwater and reuse of fracturing water. Chesapeake often works directly with local officials to arrange water purchases from a municipality when drilling inside city limits. Water is typically transported by truck to drilling locations for storage prior to use in tanks or impoundments. Chesapeake also uses temporary pipelines to transport water supplies. Due to the extensive and diverse geographic area overlying the Marcellus Shale, the overall mix of water sources used depends on the region and the availability of sources near drilling sites.

Are water resources protected and regulated?

Regardless of the source, water used in the drilling and fracturing process by Chesapeake is purchased and, if necessary, properly permitted. This permitting ensures that water used for drilling and hydraulic fracturing does not interfere with the available supply for other users. In addition, both Pennsylvania and New York require an impact analysis to ensure that the surface water withdrawals will not harm the watershed or other users. The assessments ensure that our use will not adversely affect stream flow, aquatic life, recreational resources or sensitive environments.

Chesapeake works collaboratively with regional, state and local agencies to ensure that water use for deep shale gas development is consistent with water use plans and does not adversely affect other users.

In the Marcellus Shale area, regional river authorities have jurisdiction in multiple states. The federally established watershed authorities have been created to protect the water quality of the entire river basin and to regulate uses of the water. Additional approvals and permits are required for operations in these river basins. Chesapeake actively works with the Delaware River Basin Commission (DRBC) and the Susquehanna River Basin Commission (SRBC) to obtain water for use in Pennsylvania and New York.

Chesapeake's deep shale gas development, with its comparatively small water use per unit of energy, is consistent with the nation's energy/water strategy by making a positive energy and economic contribution at a relatively low cost to the overall water supply. Chesapeake's deep shale gas has the potential to supply decades of natural gas for the U.S., while using less water than other currently available viable energy sources.

Information Sources

- Argonne National Laboratory
- Delaware River Basin Commission
- Ground Water Protection Council (GWPC)
- Sandia National Laboratory
- Susquehanna River Basin Commission
- U.S. Department of Energy (DOE)
- U.S. Geological Survey

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