January 10, 2012

Honorable Joseph Martens, Commissioner
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Commissioner Martens:

I am writing to provide comments on the 2011 draft Supplemental Generic Environmental Impact Statement On The Oil Gas and Solution Mining Regulatory Program (dSGEIS).

My comments are based on 31 years of experience working in a variety of positions in the oil and gas industry, including Executive Vice President of Mobil Oil Corporation and Operating Officer for Exploration and Producing in the U.S., Canada and Latin America. In that role, I had oversight of all of Mobil's oil and gas drilling, both onshore and offshore, in the western hemisphere. Major projects included: Hibernia, offshore oil in Newfoundland; Sable Offshore Energy Project, gas offshore in Nova Scotia; Northeast Pipeline, gas from Nova Scotia to New England; Camisea, gas and liquids in Peru; Kearl Oil Sands, tar sands in Alberta; Cerro Negro, heavy crude oil project in Venezuela; Aera Corporation, joint venture of oil and gas producing properties in California; and several offshore oil and gas projects in the Gulf of Mexico and the ongoing operation of existing oil and gas fields and pipelines. Prior to that I was in charge of Mobil's worldwide Supply, Trading and Transportation organization, which provided the corporation's international logistics using a fleet of forty tankers, plus trading and supply offices in multiple locations. That role included short- and long-term energy demand and price forecasting, which were the basis for the Corporation's projections, plans and budgets. I have also been a director of the U.S. Oil and Gas Association; Chairman of the Mobil companies in Japan, with 5,000 service stations; a director of Tonen Corporation, with two refineries and a liquefied natural gas import terminal; and a member of a special advisory board to the Japanese Ministry of Trade and Industry on the future of energy supplies. Immediately before retiring, I was the senior Mobil executive in charge of implementing the Exxon/Mobil Merger.

I recognize that the dSGEIS is a major undertaking. The 2011 dSGEIS has several significant improvements over the 2009 version, particularly with respect to some aspects of containment and handling of chemicals, additives, flow-back and fuels. Many individual aspects of the draft still need improvement, and the DEC needs to address several missing or inadequately covered topics before the document can be considered complete and in compliance with applicable law.

Wherever possible, on specific issues, I have tried to provide suggestions for alternatives that could be more effective or safer than what is currently proposed in the dSGEIS. In most cases my suggestions can stand on their own, and are not contingent upon other suggestions being adopted. In some cases an issue crosses several topics and needs to be addressed in each topic. This is particularly the case with respect to the proposed regulation of wells using less than 300,000 gallons of fracturing “water” under the 1992 GEIS, while larger wells would be regulated under the current dSGEIS. I have mentioned this issue in several of my comments. Where possible, comments have been grouped with related activities or issues.

I hope that you will consider my comments carefully. Please feel free to contact me if you have any questions or if you would like additional information.

Respectfully submitted,

Louis W. Allstadt
cc: Governor Andrew Cuomo

L.W. Allstadt Comments on New York State Department of Environmental Conservation 2011 Draft Supplemental Generic Environmental Impact Statement

Comments on fracturing fluids

Evaluation of "Greener" Fracturing Additives

The safety of fracturing fluids has been a major focus of public concerns with the hydraulic fracturing process. The dSGEIS provides a method to alleviate some of that concern. The DEC will encourage "greener" drilling fluids and points out that "further research into each alternative is warranted to fully understand the environmental impacts and benefits of using any of the alternatives. In addition, the claimed benefits of such alternatives would need to be evaluated in a holistic manner, considering the full lifecycle impact of the technology or chemical." (dSGEIS 9.3) The DEC provides sound reasoning for this approach, which should help assure the safety of any proposed alternative fracturing additives. However, the DEC offers no such provision for requiring that <u>current</u> fracturing fluid additives be evaluated in the same "holistic manner, considering the full lifecycle impact of the technology or chemical." Without the same rigorous evaluation of current fracturing fluid additives, there is no basis for comparison to assure that newly proposed fracturing additives are in fact less dangerous. In addition, without a rigorous analysis of current fracturing additives, there is no basis for knowing which of them are less dangerous than others or which are so dangerous that they should not be allowed at all. **The DEC should apply the same rigor to current fracturing additives. No fracturing fluid additive, whether currently in use or proposed as an alternative, should be allowed until it undergoes this rigorous evaluation.**

Operator's utilization of alternative fracturing fluids

Appendix 6 to the dSGEIS, Proposed Environmental Assessment Form Addendum, requires applicants to affirm "Operator will utilize alternative fracturing additive products that exhibit reduced aquatic toxicity and pose less risk to water resources and the environment, unless demonstrated to DMN's satisfaction that they are not <u>equally</u> effective or feasible" (emphasis added).

This provision leaves three loopholes. First, the applicant could avoid using an additive which might be much safer if it is slightly more expensive or slightly less effective. If the DEC is serious about moving toward safer fracturing additives, it must **require the use of demonstrably safer additives**, even if they are somewhat more expensive or somewhat less effective. Second, Appendix 6 does not apply to wells using less than 300,000 gallons of fracturing water (dSGEIS 3.2.3). Therefore, applicants for wells of that size would not have to affirm that they would use safer fracturing fluids, and the DEC would have no way of knowing whether they would or would not do so. The DEC should use the **same standards for additive safety**

regardless of the fracturing volume. Third, the process for evaluating proposed alternative fracturing fluid additives could require a significant amount of time during which alternatives would not be available. This should not be used as a delaying tactic to slow or prevent the use of safer additives. **Unless the DEC subjects current fracturing additives to the same evaluation as proposed new additives, many wells may be drilled with current, less safe fracturing additives**.

Identifying markers in fracturing additives

The oil and gas industry regularly uses isotopic or chemical markers to track the direction, speed, location and/or intensity of many processes when they want to know what is happening in that process. Markers can be used in many drilling operations, but the industry has been reluctant to use markers to track fracturing or drilling mud additives. This topic is not addressed in the dSGEIS.

Use of unique markers placed in individual fracturing and/or drilling mud additives prior to transport to a specific well or well pad, could help identify the additive in cases of spills, or accidents during the transportation, storage, handling, drilling, fracturing, flow-back, treatment of flow-back, and disposal of the treatment process effluent. Such markers would not make any of the processes inherently more safe, but operators and personnel, knowing that problems could be tracked, are likely to take more care than they might if the source of accidents or errors cannot be pinpointed. In addition, markers would remove any doubt about responsibility in those cases where water wells are damaged. **The DEC should require the use of markers in drilling and fracturing additives.**

Comments related to the drilling/fracturing process

Multi-Well Pads

The dSGEIS (5.4.2) correctly cites the benefits of drilling multiple wells from the same well pad: less surface disruption for pads, roads and gathering pipelines, and lower costs. In addition, multi-well pads generally allow closer supervision, which can improve safety and efficiency, and easier access for DEC inspection. The dSGEIS anticipates that the industry will construct about 90% of its wells on multi-well pads. However, with all of these benefits, the dSGEIS does nothing to assure that the preponderance of wells will in fact be drilled from multi-well pads.

The DEC should require any permit application for a single well to explain why it cannot be drilled from a multi-well pad. The DEC should set a target of at least 90% of wells to be drilled from multi-well pads, and should monitor progress toward that target.

Open pits

The current draft SGEIS takes some positive steps toward protecting ground water and aquifers by requiring that most fracturing additives, flow-back fluids, chemicals, and fuels be stored in enclosed containers within secondary containment areas. (7.1.3.3/7.1.3.4) The draft also requires that precautions be taken when transferring such fluids. However, the document allows alarming exceptions:

The dSGEIS proposes that wells using less than 300,000 gallons of "fracturing water" be regulated under the 1992 GEIS. The1992 GEIS allows open pits. This is a loophole that should be closed. Best practices in the industry would require closed containment. **The dSGEIS requirement for closed containers and secondary containment should be applied to all wells, regardless of fracturing volumes.**

The dSGEIS would also allow some drill cuttings and drilling fluids to be held in open pits (7.1.3.3). Regardless of the type of drilling fluid used, drill cuttings may contain hazardous chemicals or bacteria brought to the surface during the drilling process.

No open pits for storage of anything other than clean, fresh water should be allowed in drilling, fracturing or any other process associated with gas drilling and production.

Wells using less than 300,000 gallons of fracturing water

The 2011 draft SGEIS proposed regulations regarding wells using less than 300,000 gallons of hydrofracturing "water" make no sense.

The 2001 draft SGEIS provides no rationale for defining wells using 300,000 gallons or more of fracturing water as "high–volume hydrofracturing wells." The SGEIS offers no discussion whatsoever about why this would be an appropriate definition. The largest volume mentioned in the 1992 GEIS was 80,000 gallons. 300,000 gallons would be an almost fourfold increase, with no justification.

No plausible rationale exists for the DECs proposal to issue permits for wells using less than 300,000 gallons of fracturing water under the 1992 GEIS. The 1992 GEIS was not written to cover this new type of drilling and fracturing. The 1992 GEIS envisioned fracturing water volumes in the 20,000- to 80,000-gallon range. The practice of fracturing in tight shale formations had not yet been developed.

Fracturing in tight shale formations with less than 300,000 gallons of water is much more closely related to fracturing in tight shale formations using larger volumes of water than it is to fracturing in the more conventional formations covered by the 1992 GEIS.

Under the DEC's proposal, wells using less than 300,000 gallons of fracturing water would not be required to use closed containers and secondary containment for fracturing additives, drilling fluids and other chemicals and fuels. Open pits and less safe casing would be permitted and many other, less safe, procedures would apply to wells that are otherwise very similar to wells using more fracturing fluid.
Under the DEC's proposal, applicants for such wells would not be required to include information on compliance with local comprehensive plans or land use ordinances, and the DEC would have no obligation to inform local governments of permit applications under the 1992 GEIS. Local governments would have no way of knowing whether drilling operations with less than 300,000 gallons of frack water might be coming to their area, other than to constantly monitor permits issued by the DEC.

Any or all of the above-mentioned inconsistencies could result in adjacent wells being regulated under two significantly different protocols. This is absurd. **The final SGEIS should apply to all gas wells in tight shale formations, regardless of the fracturing volume.**

Well Construction

The casing and cementing requirements described in 7.1.4.2 of the 2011 dSGEIS are an improvement over the previous draft. The requirements prior to fracturing are in the right direction but should include a requirement that seismic evaluation be obtained before the first fracturing cycle. This procedure is needed to assure that there are no geological faults that can be reached during the fracturing process. In addition, the "pre-frac" form should be required before first frac and before every subsequent frac of the same well. The form for subsequent fracs should include information on any changes, additions or deletions in equipment, (e.g. whether blow-out prevention equipment has been replaced or modified). The pre-frac form for subsequent fracs should also require a new cement bond evaluation log and an internal pressure test of the production string in order to assure the integrity of both casing and cement immediately prior to the next frac. Repeated fracturing of the same well may be needed to maximize production in the tight shales **The DEC should require this information prior to each successive frac job in order to assure the integrity of both casing and cement immediately prior to the next frac.. The DEC should also reserve the option of requiring additional seismic evaluation whenever any anomalies are reported as a result of a fracturing operation.**

Geological Faults

The 2011 draft SGEIS leaves out important information with regard to the extent of geological faults, and does not provide for mitigation for drilling near such faults.

The 2011 draft SGEIS figure 4.13 shows only limited geological faulting throughout the likely Marcellus and Utica shale drilling areas. This figure obscures critical information. The tiny print on Figure 4.13 indicates that it was compiled in 1977 and that it excludes important data. Later maps by other authors (e.g., R. G. Jacobi, 2002) show many more faults. Hydrofracturing near such faults can open up channels for the migration of fracturing fluids and methane to drinking water aquifers and to the surface and atmosphere. **The draft SGEIS has failed to disclose this important information, and no mitigation has been proposed to deal with it**.

The draft SGEIS requires a one mile distance from a proposed new gas well to an abandoned gas well, because old wells can provide channels to drinking water aquifers and the surface. Geological faults can provide potentially much larger channels than abandoned gas wells. Applicants and drilling contractors should want to avoid such faults in their own interests, but the DEC should not allow them to take chances. **The DEC should at a minimum require that permit applications identify all known geological faults within a radius of at least two miles from any part of the proposed well. The identification of geological faults should be determined by recent data such as seismic evaluations. Drilling should not be permitted near known geological faults.**

Section 4.5 of the draft SGEIS plays down seismic activity in the potential shale drilling areas of New York State based on historic data during a period when there was no high volume horizontal hydrofracturing in New York. Recently there have been reports of earthquakes in Oklahoma and in the United Kingdom that have been directly linked to hydrofracturing activity, both in location and time. **The DEC needs to investigate these recent incidents and determine the probability of similar occurrences in New York <u>before</u> high volume hydrofracturing is allowed to proceed.**

Periodic subsidence checks

Surface subsidence is a not-uncommon issue with oil and gas wells as they age. The practice of high-volume horizontal hydrofracturing tight shale is relatively new. We simply do not know whether it will be an issue. Even if it is not an issue in the early stages of producing from a single formation, it could become an issue in the future, particularly in areas where production might occur in multiple formations, e.g. Marcellus, sand stones and Utica. Subsidence could interrupt or alter the flows of water through drinking water aquifers. Corrective actions may be possible if subsidence is detected early enough. **The DEC should require periodic checks of surface elevations to determine whether subsidence has begun in an area so that corrective actions can be taken.**

Applicant and personnel qualifications and experience

Neither the current Application Form for Permit to drill (dSGEIS Appendix 4), nor the current Environmental Assessment Form for Well Permitting (dSGEIS Appendix 5), nor the Proposed Environmental Assessment Form Addendum, nor any of the Oil, Gas and Solution Salt Mining Forms that appear on the DEC's website, requires any kind of demonstration of experience, competence or history of safe operation from the applicant, the drilling contractor, the fracturing contractor or any other key personnel. Registering as an operator or contractor with the DEC requires little more than name, address and phone number. **The DEC should require key personnel to state their experience and safety record in a way that can be verified. Permits should be denied for any well permit application that cannot demonstrate competency of key personnel.**

Comments related to drinking water sources

Municipal Water Sources

The dSGEIS stipulates a *temporary (3 year)* 2000-foot setback around public water supplies in the form of lakes and reservoirs. The setback for streams feeding those public water supplies would be only a temporary 500 feet; and that protection could also be reduced to 150 feet after 3 years. Any contamination that enters a tributary would quickly find its way to the lake or reservoir. Therefore, the whole municipal water source is really protected by a temporary 500-foot buffer around the tributaries, which could be reduced to as little as 150 feet (as would apply to any other stream) after 3 years. This is significantly less protection from the drilling and fracturing processes than would be afforded to the New York City and Syracuse municipal drinking water sources.

The SGEIS proposes that the Syracuse and New York City watersheds should be protected with a 4000-foot buffer extending from the watershed, because the EPA has granted those water systems exemption from filtration requirements by Filtration Avoidance Determinations. However, no municipal water treatment facility anywhere in New York State is equipped to remove the chemicals in fracturing fluid or drilling waste which could potentially enter the water source due to accidents, equipment failure, human error or natural disasters. As noted in the dSGEIS, filtering out dissolved chemicals from the fracturing and drilling processes is virtually impossible, or prohibitively expensive. **All municipal watersheds should be protected by the same 4000-foot buffer.** Unless the DEC requires the same buffer for all municipal water systems, logic would require the DEC to reduce the Syracuse and New York City buffers, in the event that the EPA withdraws their Filtration Avoidance exemptions. Surely that is not the DEC's intention.

Gas well setbacks from municipal drinking water sources for all municipal water sources must be increased to the distances for New York City and Syracuse, and must be made permanent.

Gas well setbacks in and around Primary and Principal Aquifers

The dSGEIS proposes different levels of review and protection for Primary and Principal Aquifers. Both Primary and Principal Aquifers are defined as "highly productive aquifers". The distinction is based only on whether they were in 1981 "presently used as sources of water supply by major municipal water systems", Primary Aquifers are those which in 1981 supplied major municipal water systems, and Principal Aquifers were those that did not. (dSGEIS 2.4.4.1) The dSGEIS provides no indication of what criteria were used to make this distinction in 1981 and provides no comment on whether these distinctions are appropriate for the purpose of establishing mitigations to protect these "highly productive aquifers". The map of Primary and Principal Aquifers Hudson-Mohawk Sheet (WRI 87-4275 on DEC website) covers much of central New York. It shows only two Primary Aquifers, which are located in Schenectady and Clinton NY—both of which are outside the likely shale gas drilling areas. Not listed are any other municipalities within the area of the map, many of which approach the size of the two areas designated as having Primary Aquifers. Also, some Principal Aquifers communicate with the lakes and reservoirs that provide municipal drinking water to large numbers of tourists, vacationers and part time residents—half a million a year or more— in addition to their full-time residents (e.g., Otsego Lake and the Finger Lakes). The dSGEIS does not take a hard look at why there should be any distinction in the level of protection afforded these areas. The dSGEIS should recognize that for any community, loss of its drinking water aquifer would be a disaster from which it would be difficult or impossible to recover.

The dSGEIS would bar any well pad within the boundary of a Primary Aquifer, or outside but within 500 feet of the boundary. Again, this is almost meaningless in the likely shale drilling area. For a Principal Aquifer, the dSGEIS would require a site-specific SEQRA review and determination of significance, and a site-specific SPDES permit for any well pad within the same distances. The need for these restrictions would be re-evaluated after two years. (7.1.3.5)

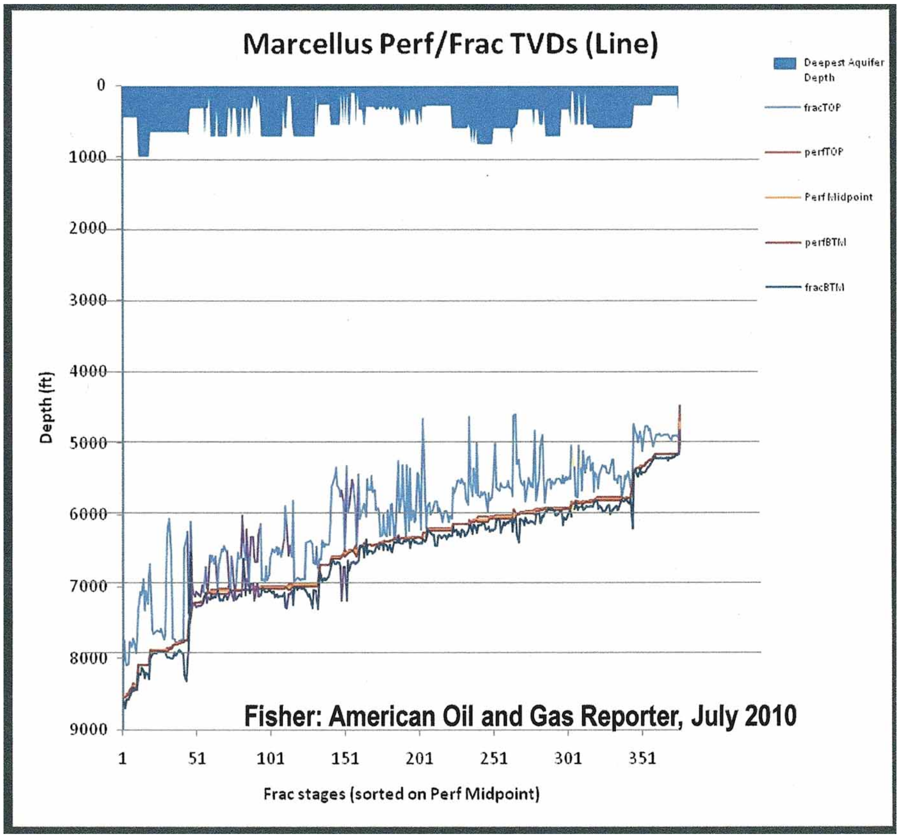
A study by researchers from Duke University (Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing, Osborne et al. 2011) showed methane migration to water wells that were located 3000 feet from active producing gas wells. The methane has to reach aquifers before it can reach water wells. The dSGEIS (7.1.11.1) attempted to discredit this study by pointing to a single gas well in Otsego County where there were no unusual levels of methane detected in nearby water wells. However, the well in question, Ross 1 in the Town of Maryland, was a test well. It was never connected to a gathering system and was never an active producing well (see DECs on-line well data report). That gas well never should have been included in the data. The rest of the data using active producing wells in other states showed a significant probability of migration of methane from gas wells to water wells up to 3000 feet away**.** The DEC should reevaluate that study, eliminating the erroneous data point. **Protection for both principal and primary aquifers should be permanent, and the 500-foot setback should be increased to at least 3000 feet.**

Gas well depth below drinking water aquifers

Industry statements lead the public to believe that fracturing will occur many thousands of feet deep, so that the fluids cannot reach drinking water aquifers. To date most industry experience with horizontal high-volume hydraulic fracturing in tight shales is with relatively deep wells, about 5,000 to 14,000 feet deep. These wells are in fact many thousands of feet (4000 to 13,000 feet) below drinking water aquifers. This is simply because the shale is at these depths in currently active drilling areas, so most experience is with a very large separation between the depth of the fracturing zone and the depth of drinking water aquifers. However, the dSGEIS (6.1.6.2) implies that 1000 feet is a safe distance below drinking water aquifers for horizontal high-volume hydrofracturing.

The draft SGEIS proposes that the top of the target fracturing zone must be 1000 feet below the deepest drinking water aquifer or 2000 feet below the surface, whichever is deeper. This is far shallower than most wells have been drilled to date. Also, the dSGEIS states, "A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water, however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data." (dSGEIS 2.4.5) Under the dSGEIS proposed depth, a potable water aquifer that is 850 feet deep would be protected by only 1000 to 1150 feet of distance from the fracturing zone.

Industry data shows fractures exceeding draft SGEIS proposed distances at times. Thus, fracturing at shallow depths, as the draft SGEIS would allow, could result in fracturing fluids or methane gas reaching an aquifer. The following data is for the Marcellus shale. It shows some fractures extending more than 1800 feet vertically.



There are no data points in this study for wells less than 5000 feet deep in the Marcellus Shale. Few Marcellus shale wells in New York State will be as deep as those shown on the graph, simply because the Marcellus shale only reaches 5000-6000 feet in a few areas. Thus, most Marcellus shale wells in New York will be closer to the drinking water aquifers. Some industry studies suggest that fractures may not extend as far vertically at shallow depths as fractures in deeper wells. However, no data exists to confirm this for wells fractured in the Marcellus shale.

Appendix 11 of the dSGEIS explains why theoretically it should be difficult for fracturing fluids to travel great vertical distances. This is probably true for fracturing fluids within the assumptions used. However, those assumptions ignore the possibility that "a network of open fractures, an open fault, or an undetected unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer." Appendix 11 also notes that in EPA studies it has been possible to measure directly the extent of fractures where mining has uncovered previous fractures in coal bed methane formations. "The coalbed studies indicate that fracturing fluids follow the natural fractures and can migrate into overlying formations. EPA also reported that in half of the cases studied, fracturing fluids migrated farther than and in more complex patterns than predicted. In several of the coalbed studies, the frac fluids penetrated hundreds of feet beyond the propped fractures, either along the unpropped portions of the induced fractures or along natural fractures within the coal." In other words, the EPA has evidence, by direct measurement of previous hydraulic fractures uncovered by mining operations, that fractures can extend farther and in more complex patterns than was predicted.

Note that the potential impact on drinking water aquifers is not limited to fracturing fluids. Under similar conditions methane gas should move faster and in greater volume than liquid fracturing fluids. Note also that data on hydraulic fracturing in the Utica shale, which lies below the Marcellus Shale, is very limited. The Utica shale reaches shallow depths further north than the Marcellus shale.

Thus, we really do not know what depths are safe. Contamination of drinking water aquifers can be irreversible. A cautious approach is needed. The DEC should establish safer vertical distances. A minimum of 3000 feet below the deepest drinking water aquifers and the top of the target formation, or 4000 feet below the surface, would be considerably safer and would provide some buffer against human error and mechanical failure, which the currently proposed 1000/2000 feet depths would not do.

An increase in minimum depth requirements should have little effect on the number of wells drilled or the actual production of gas. Since pressure increases with depth, the more productive wells tend to be where the shale is deeper. Most experienced drillers prefer that shale targets be at least 4000 feet deep. Without greater depth requirements, the danger is that less experienced or less well-financed drillers will attempt wells at shallow depths.

The DEC should require a minimum of 3000 feet between any fracturing zone and the deepest drinking water aquifer, or 4000 feet below the surface, whichever is greater. Alternatively, a site-specific SEQRA review should be required. Note: the draft SGEIS as proposed does not apply to wells using less than 300,000 gallons of fracturing water. Those wells would be regulated under the outdated 1992 GEIS, which does not specify a minimum depth requirement. **The minimum depth requirement should apply to <u>all</u> oil and gas wells— regardless of the volume of fracturing fluid used.**

With regard to the depth of the deepest potable water aquifers, it should be noted that water well drillers normally stop when they have obtained sufficient flow rates, so the depth of water wells in an area indicates only the presence of potable water at that particular depth. It does not necessarily indicate the maximum depth of potable water. Consistent with dSGEIS (7.1.4.2), **a cautious approach to establishing potable water aquifer depth would be for the regulations to use 850 feet or the maximum known depth in the area, whichever is greater.**

Water wells

Vertical distances

The comments above under **Gas Well Depth below Drinking Water Aquifers** also apply to domestic and municipal water wells as they are also supplied from the aquifers. **The DEC should require a minimum of 3000 feet between any fracturing zone and the deepest drinking water aquifer.**

Horizontal distances

The proposed gas well setback from a private water well or domestic supply spring would be 500 feet, 'unless waived by the landowner.' (dSGEIS 7.1.11.1). I again refer to the study by researchers from Duke University (Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing, Osborne et al. 2011) showed methane migration to water wells that were located 3000 feet from active producing gas wells. The dSGEIS attempted to discredit this study by pointing to a single gas well in Otsego County where no unusual levels of methane were detected in nearby water wells. However, the well in question, Ross 1 in the Town of Maryland, was never an active producing well (see DECs on-line well data report). That gas well never should have been included in the data. The rest of the data using active producing wells in other states showed a significant probability of the migration of methane from gas wells to water wells up to 3000 feet away**.** The DEC should reevaluate that study, eliminating the erroneous data point. **The DEC should establish minimum horizontal distances between proposed gas wells and water wells of 3000 feet until such time as additional and definitive data is available on the migration of methane from gas wells to water wells.**

Health impacts of Methane in Water

There are no established safe levels of methane in drinking water. **The New York State Department of Health should establish methane standards for drinking water, and the DEC should require that gas well operations assure those standards are met**.

Floodplains

The 100-year flood plain has been breached three times in upstate New York over the last five years, which indicates that the currently designated floodplain maps are sorely out of date. The DEC should not allow drilling to occur near floodplains until FEMA has updated New York's floodplain maps. Flooding in the regions surrounding the Delaware and Susquehanna Rivers and their tributaries poses an enormous risk if any drilling is allowed in a floodplain. Without accurate floodplain maps, the DEC is at risk of permitting drilling in areas that are now effectively floodplains, based on the 2006, 2010, and 2011 floods.

The dSGEIS (7.2) states that high-volume hydraulic fracturing will not be allowed within the 100-year floodplains. The draft notes that flooding is one of the ways in which drilling brine and flow-back fluids could be released into the environment. (Section 6.2) In addition, any chemicals or fuels that are stored on a well pad could be released if the pad is flooded. Safety margins are needed around floodplain maps.

Until such time as updated floodplain maps are available, the DEC should establish a safety buffer around the old floodplain maps of at least 1000 feet, and more in any cases where 1000 feet might not be adequate.

When updated flood plain maps are available, either 500-year floodplain maps should be used, or a permanent safety buffer of at least 500 feet should be established around updated 100-year floodplain maps.

Air Quality

In other shale gas and shale oil producing areas air quality has been a significant problem, due to methane and VOC emissions. Many of these problems appear to be associated with poor construction or poor operating practices at well pads, pipelines, treatment plants, and compression stations. It is unclear whether design flaws in facilities have played a role. Also unclear is whether the work force has been properly trained to build and operate such facilities. The dSGEIS has proposed several means for mitigating air quality issues. In order to assure that those mitigation methods are working, the DEC <u>must</u> develop efficient methods of monitoring air quality. Infrared photography and videography are capable of revealing gas leaks around facilities. **The DEC should investigate using such equipment or other means to monitor likely or suspected sources of air pollution.**

Socio-economic factors

The 2001 draft SGEIS economic projections are based on overstated, outdated and inaccurate estimates of recoverable gas reserves that are five to six times the quantity of gas that the United States Geological Survey estimates is technically recoverable. "The Marcellus Shale contains about 84 trillion cubic feet of undiscovered, technically recoverable natural gas and 3.4 billion barrels of undiscovered, technically recoverable natural gas liquids according to a new assessment by the U. S. Geological Survey (USGS." (August 23, 2011). However, the 2011 draft SGEIS states, "the most recent estimates by Englander …indicates a 50 % probability that recoverable resources could be as high as 489 TCF." The US Energy Information Agency, which had also previously provided high estimates, has cut its estimates to reflect the USGS estimate. **The entire socio-economic impacts section (6.8) should be rewritten to reflect the lower estimates**.

Actual production profiles for unconventional shale wells typically show a very steep decline of approximately 70% in the first year. There is no data on long-term production from these wells, but more and more industry experts are questioning how long these wells will continue producing. Continuation of production for 30 years, as assumed in the draft SGEIS, especially without several additional hydrofracturing treatments, is highly unlikely. This exaggeration, in conjunction with the overstatement of recoverable reserves, has led to extreme inflation of the claimed economic benefits. **The DEC should revise the entire socio-economic section to reflect realistic production profiles and to include the disruption to communities and the extra road repair costs of repeated fracturing.**

There is no discussion or examination of the boom/bust cycle typically associated with the impact of oil and gas drilling on local economies, as described by Barth, Christopherson and other economists. The draft SGEIS considers only ongoing economic benefits to the prospective shale gas region in its entirety. The impact will not be a smooth average spread evenly over time across the entire region. It will more likely be a series of short- term booms and busts from one town to the next, with short-term economic booms created by a migrant work force during the drilling phase and then a contraction when the drilling moves on. **The draft SGEIS fails to address this issue and proposes no mitigations. This important subject needs to be included.**

Section 6.8 ignores many reports from banks and insurance companies which indicate that nearby gas drilling adversely impacts home owners' ability to obtain mortgages and insurance. **This adverse economic impact should be included.**

The socio-economic section contains virtually no social impact analysis. Section 6.8 brushes off adverse impacts on the lifestyles of people in parts of the region who have chosen to live in rural, non-industrial settings. In portions of the possible shale gas region in New York State, existing local economies are based largely on agriculture, tourism, second homes, health care and tertiary education. Many of these communities consider gas drilling to be incompatible with their current local economies and incompatible with the long-term vision for their communities as expressed in their Comprehensive Plans. The draft SGEIS barely mentions this, and does not seriously examine the economic or social impacts. **The economic and social impact of changing to a heavily industrialized economy must be examined and acceptable mitigations proposed before the draft SGEIS can be considered complete**.

Truck traffic

Everyone living near or traveling through drilling areas in upstate New York would experience the negative impacts of HVHF in the form of drastically increased truck traffic.

According to the dSGEIS (table 6.60), each single horizontal well requires 1,149 heavy truck trips and 831 'light' trucks, one way, which means roughly 4,000 truck trips per well. Table 6.63 shows that Region B, for example, would have 82,203,000 annual heavy truck trips under an average development scenario. Other regions have similar projected huge increases in truck traffic. Furthermore, the DEC has seriously underestimated the total number of trucks that would impact the area near each well pad. The DEC's numbers include only trucks directly involved in the drilling process, not the additional trucks and equipment required to build gathering pipelines and compression stations, or to build or repair the roads that will be damaged by all the other trucks. **The DEC should provide a realistic study of trucking impacts in conjunction with the New York State Department of Transportation.**

Much of the truck traffic associated directly or indirectly with drilling will move over county and town roads. Many counties and towns are in the process of developing road use ordinances and road use agreements. **The DEC should require drillers to include in their permit application a certificate from the Town and County where the well is located, stating either that the Town or County has no road use ordinance or that the driller has agreed to a road use agreement. Without such a certificate, the permit application should be considered incomplete.**

Most of the truck traffic associated with each well will move a significant part of the distance on state roads. The dSGEIS provides no input from the New York State Department of Transportation about: the ability of state roads and bridge infrastructure to handle this large increase in traffic; the costs that would have to be incurred to bring state roads and bridges up to standards that can handle the increased traffic; or the ongoing costs to maintain state roads and bridges with increased use. Drilling impacts on state roads will affect not only drilling and drilling-related use of state roads, but also the use of those roads for non-drilling-related commercial, commuter, tourist and other transportation. New York State currently has no revenue source derived from gas drilling that would help to pay for the damages done to state roads and bridges. The impact of trucking associated with shale gas industrialization can be massively disruptive to rural communities. The DEC has no regulatory authority over trucking. Indeed, the state has no ability to enter into road use agreements with trucking operations. **The DEC, in conjunction with the NYS Department of Transportation, should provide a comprehensive analysis of drilling and drilling-related impacts on state roads and bridges, as well as a concrete plan for covering the costs of these impacts.**

Waste transportation tracking

The dSGEIS explains in some detail the limited number of alternatives for treatment of fracturing flow-back fluids. Under the Proposed Supplementary Permit Conditions (Appendix 10), condition 55 states: "Transport of all waste fluids by vehicle must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. *The Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of *The Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility." Such a system may facilitate after-the-fact investigations, provided operators strictly adhere to all paperwork procedures. It is, however, an antiquated, paper-based system, which does nothing to facilitate compliance or safety while transportation is actually occurring. Most trucking fleets now use real-time GPS tracking, which is available immediately in a central location to assure that vehicles can be located in the event of an accident, that they comply with speed limits, and that they use appropriate roads and follow any prescribed procedures. **The DEC should work with the Department of Transportation to establish a real-time system for tracking waste which does not rely on burdensome paperwork and which will enhance safety.**

Produced fluids, sometimes referred to as brine, will continue to be produced for the life of each well and will have to be transported for disposal. The makeup of this produced fluid is similar to that of the initial flow-back fluids. It fits into the category of "transport of all waste fluids by vehicle," per supplementary permitting condition 55. This brine is produced at a slow rate, but the cumulative amount for each well is large and may eventually be equal to the initial flow-back volume. Dealing with brine requires a significant amount of transportation over time. Pennsylvania has had criminal cases regarding truckers who have dumped this material rather than transporting it to an appropriate disposal location. Transportation of produced fluids (or brine) should also be subject to a tracking system. However, because the truck driver is often the only person at the well site when the produced fluids are loaded, a paper tracking system maintained by the generator may be impractical. Again, a real-time GPS-based tracking system reporting to a central location offers safety advantages. In any event, t**he DEC should include produced fluids in whatever tracking system is used for all other waste fluids.**

<u>Distance from homes and public buildings</u>

The distance from a person's home to an invasive industrial activity is of utmost importance. The distance from schools, hospitals, offices, and other places where large numbers of people congregate to invasive industrial activities is also of extreme importance. The public had every reason to expect that this information would be prominent in the 2011 SGEIS. It is not. The 2011 draft SGEIS makes no mention of proposed setback distances from gas well pads to homes or public buildings like schools, hospitals, nursing homes, libraries or other public buildings. The 2009 draft SGEIS likewise makes no mention of these distances. One must search back to the 1992 GEIS to find such distances, and that GEIS mentions only distances from gas wells, not from well pads. The 1992 GEIS and §553.2 establish well distances from dwellings at 100 feet and from public buildings at 150 feet.

The distances that were recommended in the 1992 GEIS—which would remain in effect under this draft SGEIS—were developed for a completely different type of drilling, before high-volume horizontal hydrofracturing in tight shale formations came into use. The 2011 SGEIS gives no adequate justification for these very small setbacks.

The setback examples in other states given in the 2011 SGEIS are unchanged from 2009 and are out of date. Numerous localities in other states require far greater setbacks, and some have been recently increased. The following examples are taken from readily available public information for each locality as of October/November 2011

	House	Schools, etc.	Others
Flower Mound, TX	1500'	1500'	500' from floodplain 750' from property line
Midland, TX	1320'	1320'	
Southlake, TX	1000'	1000'	1000' from property line
Colleyville, TX	1000'	1000'	
Lewisville, TX	800'	800'	
Fort Worth, TX	600'	600'	
Arlington, TX	600'	600'	
Santa Fe County, NM	750'	750'	600' from property line
Arriba County, NM	650'	1000'	
Valencia County NM		1000'	

Common sense alone says that 100 feet from a home or 150 feet from a school for a gas well is totally inadequate. **The DEC needs to increase significantly the setbacks from homes and public buildings. The definition of public building should be clarified to include all structures in which people gather for any purpose.**

Local comprehensive plans and land use ordinances

The 2011 draft SGEIS places unnecessary burdens on towns to assure that drilling applications are correct.

The draft 2011 SGEIS allows drillers to self-certify whether a permit application is in conflict with local comprehensive plans or land use laws. This leaves the local government in the difficult—if not impossible— position of having to check all applications to see what the driller has certified. The process should be reversed. The applicant should be required to produce certification from the local government stating that the permit application is consistent with local comprehensive plans or land use laws or that no such local plans or laws exist. P**ermit applications should be considered incomplete without certification of compliance from the appropriate local government.**

The dSGEIS would require this certification of compliance with local comprehensive plans or land use laws <u>only for wells with greater than 300,000 gallons of fracturing fluids</u> (3.2.2.1). The requirement to certify compliance with land use laws should apply to all drilling, regardless of the size of the well, well pad or fracturing volume. The current draft SGEIS leaves a loophole allowing the driller and the DEC to ignore local regulations if a well is small enough. A small well can be just as inconsistent with local comprehensive plans or land use laws as a large well. There is no reason to treat wells differently for this purpose depending on their size. **The DEC should remove all references to any minimum amount of fracturing that would exempt drillers from certification of compliance with local comprehensive plans or land use laws.**

The first paragraph of the 2011 draft SGEIS (7.12) states, "Local and regional planning documents are important in defining a community's character and are a principal way of managing change within a community. These plans are used to guide development and provide direction for land development regulations (e.g., zoning, noise control, and subdivision ordinances) and designation of special districts for economic development, historic preservation, and other reasons." However, later in this section, the DEC says if there is an inconsistency with land use laws the DEC would investigate "to determine whether this inconsistency raises significant adverse environmental impacts that have not been addressed in the SGEIS " (7.12 and 8.1.1.5)). **The words "adverse environmental impacts" should be broadened to include adverse impacts on a community's character that are inconsistent with local land use laws and other ordinances. The DEC should simply require drillers to comply with local land use laws.**

Financial Security

Financial security for the plugging and abandonment of wells

Almost no one pays any attention to the end of the life of an oil or gas well. The original drilling company sometimes holds a well for its entire productive life. However, it is not unusual for the ownership of a well to change several times. The original owner may solicit offers on a group of wells, or he may receive unsolicited offers. In either case, at some point, a company with lower overheads and less expensive operating costs will offer to buy the old wells at a price that gives the original company a better return than it would earn from continuing operations. The original company uses the cash to finance new investments. The buying company operates with lower costs, because it spends less on maintenance and safety items and has fewer or less qualified people to pay. The chain may end there, or it may continue through smaller and even lower cost operators who do no preventive maintenance at all, and do the bare minimum of repairs to keep the well going. When a well costs too much to repair versus what it might produce, it is abandoned. Whether or not it is plugged before it is abandoned depends on the final operator. Some companies operate each well or group of wells under a separate corporate entity that is always stripped of cash, so if something goes wrong no assets are available to pay off claims or to pay for proper plugging. Not all operators function this way, but it happens.

By the time old wells are abandoned, the casings have been subjected to corrosive liquids and gases for many years. In order to prevent liquid and gas leaks from old wells, it is critical that abandoned wells be plugged, that the plugging be done with the most effective available techniques and that plugged wells be identified and periodically monitored to assure that the plugs are providing the intended protection. The DEC's own data on existing abandoned wells indicates that tens of thousands have not been plugged, and that the locations of thousands of abandoned wells are not known (R.E. Bishop, January 2012). The dSGEIS itself acknowledges this by requiring applicants to certify that they have searched for abandoned wells within a one-mile radius of a proposed new well site.

The proposed financial security requirements in the regulations (Part 551.5) for wells up to 6000 feet total depth are unchanged and are insufficient to assure proper plugging and abandonment of wells. For example, the maximum amount required per well for wells of 2500-6000 feet total depth is $5,000 for a single well. However, the cost per well decreases for additional wells, and the total security requirement is capped at $150,000. At the point where the cap is reached, the cost per well is less than $1,400 per well. Even if these amounts were sufficient when the 1992 GEIS was written, costs have increased and the dSGEIS plugging procedures will require substantially more time and materials. **The financial security amounts for wells less than 6000 feet should be increased to reflect realistic estimates of actual plugging and abandonment costs. That estimate should apply to <u>all</u> wells.**

The proposed financial security requirements for wells greater than 6,000 feet total depth (Part 551.6) would be based on the anticipated costs for plugging and abandoning a well up to a maximum of $250,000 per well and up to a total of $2 million, regardless of the number of wells. At the $250,000 amount, after the first eight wells, any additional wells would carry no additional financial security requirement.

The use of anticipated plugging costs as the basis for financial security requirements makes sense. **The DEC should establish financial security amounts based on anticipated plugging costs for <u>all wells, regardless of depth</u>**. However, costs will change over time with inflation and new technology. **The DEC should reserve the right to call periodically for increased security to cover higher anticipated costs.**

The reduction in financial security requirements based on numbers of wells does not make sense with regard to plugging and abandoning. As discussed above, plugging and abandonment comes at the end of the useful life, when the then current operating may have few assets other than the wells. For example, an operator with 100 wells over 6000 feet deep would have provided a total of $2 million in financial security. However, using $250,000 per well, the cost for plugging and abandoning 100 wells would be $25 million. Faced with the prospect of $25 million in plugging costs or losing a $2 million bond, the operator may well be forced (or choose) to enter bankruptcy. The DEC would then be left with the abandoned but unplugged wells, and the taxpayers of the state of New York would have to cover the extra $23 million to plug the wells. If this example is extended to a large number of sells, the cost to New York taxpayers could be in the billions of dollars. **To assure that wells are properly plugged and abandoned without creating a burden on the government and taxpayers of New York State, the DEC should require the same cost per well, regardless of the number of wells. Plugged wells should be periodically checked to assure that plugs are holding.**

With the current limits of financial security for plugging and abandoning, it is no wonder that tens of thousands of unplugged, abandoned wells are scattered around New York State.

Other financial security

The above financial security requirements for plugging and abandoning wells is the only financial security requirement mentioned in the dSGEIS. If an operator during any phase of his facilities useful life causes damage of any kind that is beyond his financial capability to correct, New York State would hold no financial security to cover the costs. This is a major omission in the dSGEIS. **The DEC should address**

this through additional bonding or other financial security requirements to cover non-plugging related expenses.

I strongly support New York State Controller, Thomas P. DiNapoli's letter of December 29, 2011 commenting on the dSGEIS including his proposal for the "New York Environmental Protection and Spill Compensation Fund.

Cumulative Impact

The 2011 draft SGEIS fails to address cumulative impacts or their remediation in any meaningful way.

The draft SGEIS does not evaluate the cumulative impacts of repeated fracturing of the same well, which should include the repeated application of high pressure to well casings and cement, the impacts on roads of repeated fracturing and the repeated need to treat flow-back fluids.

The draft SGEIS does not discuss mitigation of the cumulative impacts of long-term gas production and/or repeated fracturing on surface subsidence and its possible impact on the integrity of well casings and pipelines, surface structures, including homes and public buildings, or on drinking water aquifers.

The document does not discuss mitigation of cumulative impacts of drilling and fracturing (under the purview of the DEC), combined with related activities that are under the purview of the Public Service Commission. These include construction and operation of pipelines, gas treatment plants and compression stations.

The SGEIS does not consider the cumulative impacts or mitigation of dealing with the treatment and disposal of flow-back fluids and produced fluids from the large number of wells that are projected. Disposal of flow-back fluids and produced fluids to treatment plants that do little more than dilute the material before discharge into rivers or lakes will cumulatively result in increased levels of pollutants downstream. This must be addressed on a <u>cumulative</u> basis, not by treating each such discharge as a one-time inconsequential event. Similarly the effect of repeated spreading of produced fluids (innocuously referred to as 'brine") on roads must be addressed on a cumulative basis, not as single events.

The 2001 draft SGEIS does not address the cumulative public health impacts from protracted and/or repeated human exposure to fracturing additives, drilling fluids, methane gas, volatile hydrocarbons or other substances used in the drilling, fracturing, treating and transportation processes required to produce and deliver natural gas; whether that exposure occurs at the drill site as a work place, at adjacent dwellings, in or near public buildings or at any other place that people might be exposed repeatedly to substances used in the entire process.

In summary, the production and delivery of natural gas derived from unconventional tight shale formations through high-volume horizontal hydrofracturing will impact the environment; human and animal health; drinking water quantity and quality; air quality; local economies; and local quality of life. The processes involved—constructing facilities, drilling, fracturing, treating, compressing, waste handling, transporting and associated activities—will affect each and every one of these areas, and will also carry hidden costs to New York State's taxpayers. The dSGEIS covers some of these issues individually. However, it completely fails to identify or even consider the combined cumulative effects of their simultaneous application in conjunction with all other activities involved in gas extraction over a protracted time period in a given area.

The DEC should complete a comprehensive cumulative impact analysis.

Conclusions

The 2011 dSGEIS improves upon the 2009 draft in several areas but leaves many areas of serious concern. I have tried in this paper to identify and suggest ways of dealing with some of those concerns. However, the issues I have covered here are far from being a complete list of everything needed to correct problems in the dSGEIS. They are, however, an indication of the seriousness, depth and breadth of matters the DEC needs to address. The documents themselves (2011 dSGEIS, 2009 dSGEIS and 1992 GEIS) are an inadequate basis for moving forward. The 1992 GEIS is out of date and provides a very weak foundation for today. Taken together, the 1992 GEIS, the 2009 dSGEIS and the 2011 dSGEIS are a mass of information that lacks cohesion and is extremely difficult to sort through, even for people familiar with the subject matter. The DEC's searchable versions of the documents require entering a word or phrase at least 50 different times in order to find all references to that term. In many instances the documents use studies prepared by consultants who work primarily for the industry. Consequently, a bias toward minimizing concerns is evident in optimistic discussions of the industry's ability to solve the myriad problems. A further bias is apparent in attempts to discredit studies that identify potential problems with new data, when it would be appropriate for the DEC to invite further investigation or clarification.

In my view the citizens of New York State would be best served by creating a new GEIS that would replace the 1992 GEIS and the draft SGEIS.

Louis W. Allstadt January 10, 2012