Independent Oil & Gas Association of New York

December 31, 2009

Attn: dSGEIS Comments
Bureau of Oil & Gas Regulation
NYSDEC Division of Mineral Resources
625 Broadway, Third Floor
Albany, NY 12233-6500

Independent Oil and Gas Association of New York State

Subject: **Comments on Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program - Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs**

To whom this may concern:

I write in my capacity as Executive Director for the Independent Oil & Gas Association of New York State (IOGANY), representing oil and gas producers, professionals and related industries in New York State, to provide our formal comments on the *Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program* (dSGEIS).

IOGANY would like to first acknowledge the Herculean task that NYSDEC and its colleague agencies has undertaken – within a very limited time – to prepare this exhaustive review. In recent weeks, IOGA members likewise worked hard in reviewing the dSGEIS – in order to understand its operational, regulatory, environmental and commercial impacts, and comment in specific detail.

We as an industry welcome a high environmental bar. But time is now of the essence. Drilling is not new to New York, and there have not been environmental accidents associated with our industry in this State. New York needs to implement reasonable environmental safeguards, but do so quickly, to enable New Yorkers to benefit from this natural resource and the potential economic benefits in the Southern Tier of New York. In Pennsylvania – at sites just a few miles away from Broome County -- communities already are reaping the profound benefits of new exploration and production. Yet in our own Broome County – no such benefits have been seen, because of the delays in finalizing the sGEIS.

So IOGANY offers the following comments with the urgent request that the SGEIS be finalized very soon. If the SGEIS is not put into practical effect very soon, some companies may opt out of the Marcellus Shale play in New York for the foreseeable future.

The preparation of this dSGEIS was directed by Governor Paterson, pursuant to requirements of the State Environmental Quality Review Act (SEQRA), so that key differences with horizontal drilling and high-volume hydraulic fracturing (HVHF) might be analyzed. As outlined in the dSGEIS, these differences consist of:

1) the required water volumes for HVHF,
2) possible drilling in the NY City Watershed and near the Catskill Park, as well as near the Upper Delaware Scenic and Recreational River, and
3) the longer duration associated with multiwell drilling sites

In general, the expected incremental impacts are addressed in sufficient detail as to demonstrate the complexities associated with identifying specific impacts and the inability to quantify cumulative impacts at a programmatic level. However, this has not prevented the NYSDEC from including several proposed mitigation measures and procedural changes to current practices that could have implications beyond the Marcellus Shale and the State of New York. It is with this in mind that I present the following comments for your incorporation in the Final SGEIS.

ECONOMIC CONSIDERATIONS

There is a lack of discussion and analysis in the dSGEIS pertaining to the economic consequences of implementing the revised permit requirements, suggested mitigation measures and proposed water well sampling and extended monitoring. Such requirements will add additional costs to the drilling and ongoing operation of wells in New York, possibly reducing the economic viability of marginal production and ultimately reducing the recovery of indigenous natural gas resources in New York. Our association cannot advise our members or provide any meaningful data regarding the cost of developing gas in the NYS portion of the Marcellus Shale without further economic evaluation being conducted and included in the SGEIS. The Final SGEIS should include an analysis that covers the full spectrum of potential economic consequences such as: reduced development of marginal resources, reduced royalties, reduced state revenue, reduced recovery of gas, reduced supply, lost jobs and higher consumer prices.

OUT OF SCOPE

Throughout the dSGEIS there are references and examples cited that do not clearly recognize the oil & natural gas industry's ability to adapt to various site-specific conditions or employ new technologies readily. This lack of recognition appears to impose a limit or restriction on various development activities; by simply not acknowledging a range it implies that activities outside the specified quantity may not be permitted or will require additional analysis. Any proposed activity that is larger, longer or different could be considered outside the scope of the dSGEIS, thus requiring operators to prepare a site-specific environmental assessment instead of simply identifying these activities as a variance to an already analyzed practice. Examples of these instances are summarized below. We would suggest that the NYSDEC add language creating flexibility in this document by advising the reader that variances in the items discussed below are common and will not materially affect the contents of this document or its applicability.

- **Lateral Lengths of Horizontal Wellbores:** The text mentions distances of 4,000 and 4,500 feet as typical for horizontal wellbores, however, there is no discussion regarding longer wellbores or the possibility of future technology enabling larger wellbores with various patterns. Additional text addressing the factors considered in determining wellbore length such as: overburden pressures, formation characteristics, and depth would be appropriate. Additionally where 4,000 or 4,500 feet is cited a range should be inserted or a statement indicating that longer wellbores are possible.
  - Section 5.1.3.2 Anticipated Well Pad Density (page 5-19)
  - Section 5.2 Horizontal Drilling (page 5-22)
  - Section 5.7 Source Water for High-Volume Hydraulic Fracturing (page 5-74)
  - Section 5.9 Hydraulic Fracturing Procedure (page 5-93)
- **Well Development Patterns:** The dSGEIS mentions evenly spaced parallel horizontal wellbores drilled in opposite directions with as many as 16 surface locations at one pad. Again, it fails to recognize that other patterns such as tri- or quad-lateral and pinnate wellbores could be drilled from a single well if desired. Additional discussion should be provided that identifies other wellbore configurations, the characteristics associated with each, and the recognition that new technologies may make other wellbore patterns possible.
  - Section 5.2.2 Multiwell Pad Development (page 5-27)
  - Figure 5-2 – Well spacing unit and wellbore path (page 5-28)
- **Pumping Rate:** The dSGEIS states that pumping rates during fracturing can range from 1,260 to 3,000 gallons per minute. Although this may be appropriate for some wells there is no discussion of the factors considered to derive the optimum pumping rate. Companies have reported pumping rates in excess of 3,000 gpm and it should be recognized that there are many considerations when determining the most favorable pumping rate.
  - Section 5.9 Hydraulic Fracturing (page 5-94)
- **Water Sources:** The dSGEIS acknowledges that operators may withdraw fresh water for fracturing from various sources including surface and ground water, and public and private suppliers, but does not note that freshwater supplies are sometimes shared among operators. The sharing of freshwater by operators should be added to the discussion so additional analysis is avoided when this practice is proposed.
  - Section 5.7 Source Water for High-Volume Hydraulic Fracturing (page 5-74)

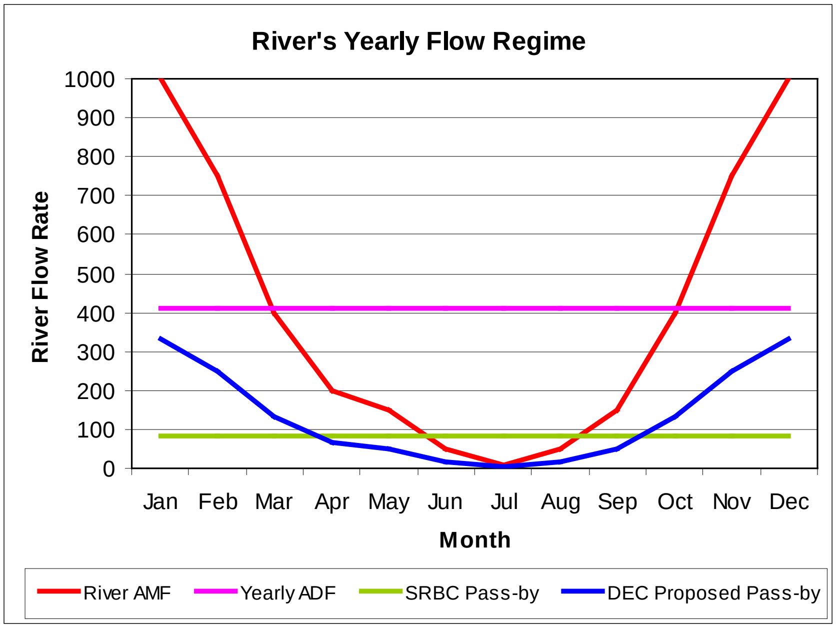
  - Section 5.7.2 Use of Centralized Impoundments for Fresh Water Storage (page 5-76)

- **Fracturing Additive Storage:** It is mentioned that no more than 12 additives or products would be stored at a well pad at one time. Again, this does not provide any room for variances and should be revised to indicate that 12 products are typical but more may be used depending on site circumstances. In addition, there should be a clarification of "storage" as it relates to items being used in stimulations where the storage of additives is very temporary.
  - Section 5.6 On-Site Storage and Handling of Hydraulic Fracturing Additives (page 5-70)

- **Centralized Flowback Impoundments:** The dSGEIS states that impoundments may be as large as five acres and only service well pads within a four-mile radius. Operators have reported constructing flowback impoundments larger than five acres that service wells further away than four miles. These sections should be changed to state ranges for size and distance or include text acknowledging that large impoundments may be constructed given site circumstances and used to service wells within a region.
  - Section 3.2.1.3 Size of Project (page 3-7)
  - Section 5.7.2 Use of Centralized Impoundments for Fresh Water Storage (page 5-76)

WATER WITHDRAWAL SOURCES

- **The Natural Flow Regime Method (NFRM):** As proposed by the DEC, the Natural Flow Regime Method (NFRM) is considerably different than the current method imposed by the SRBC. While pass-by flow restrictions are expected on the majority of streams intended to be permitted, the NFRM does not allow for uninterruptible surface or groundwater water withdrawals. A selection of uninterruptible withdrawals from very large rivers is paramount for 365 days/year operations. Under the proposed NFRM pass-by flow conditions (30% of the AMF evaluated monthly), it is expected that permitted withdrawal rates would be significantly lower than under the SRBC current pass-by conditions (20% yearly ADF). Since the NRFM would allow for a lower threshold to withdrawal during low flow months, it is troubling that the permitted withdrawal rate would be tied to the AMF in low flow months. Thus the NFRM will result in lower permitted withdrawal rates versus the SRBC method. The graph below highlights the difference between withdrawal threshold points for the NRFM versus the SRBC 20% ADF system.



Under the NRFM, pass-by flow conditions would be evaluated monthly and require additional metering, pumping and communications equipment. Therefore, implementation would be feasible but would increase the cost of a typical trucked water withdrawal site by nearly $200,000.00 or approximately 65 percent above current costs.

The DEC should allow withdrawals within the SRBC jurisdiction to be regulated by the SRBC-- to avoid duplicative rules and regulations which will invariably cause delays in permitting. Furthermore, the NFRM pass-by method should be revised so that the withdrawal rate is linked to a percentage of the AMF. Finally, the SGEIS should have provisions for uninterruptible sources by not employing the NRFM model on rivers with a yearly ADF greater than 100,000,000 gallons per day.

- Section 7.1.1.4 Impact Mitigation Measures for Surface Water Withdrawals (page 7-15 – 7-21)

Furthermore, it should be stressed that the NFRM applies to all industries withdrawing water. We believe the natural gas industry should not be the only industry required to allow pass-by flows. Other water withdrawal users should be held to similar permit requirements.

- Section 7.1.1.5 Cumulative Water Withdrawal Impacts (pages 7-21& 7-22)

- **Water Withdrawals on Stream with Less than 100 mi^2 Drainage Area:** Operators have indicated that their current water management plans are focused on reducing truck traffic and they therefore intend to rely on permitting infield streams. Many areas of operation will not have access to large rivers in close proximity to well pads. Therefore it is expected that many streams with under 100 mi^2 of drainage area will be permitted with no USGS stream gauge or surrogate stream gauge history. The dSGEIS references the "Aquatic Base Flow" calculation but does not provide a means for determining what could be expected to be withdrawn from small streams. Note, permitting water sources close to operations are critical in reducing truck traffic, which in turn reduces noise and road impacts.

The DEC should expand on the Aquatic Base Flow calculation in relation to the NFRM calculation so operators can determine what to expect regarding withdrawals from small streams.

- **Groundwater Withdrawals:** The NYSDEC's Division of Water's "Recommended Pump Test Procedures for Water Supply Applications" seems to apply in conjunction with the SRBC's aquifer testing protocol to evaluate proposed groundwater withdrawals. Again, the DEC should allow withdrawals within the identified jurisdictions to be regulated by those jurisdictions to avoid duplicate rules and regulations which will invariably cause delays in permitting. The SRBC's approval process is sufficient to control groundwater withdrawals and any findings the DEC has regarding aquifer depletion should be published in the Final SGEIS.
    - Section 7.1.1.1 NYSDEC Jurisdictions (page 7-6)
- **Primary and Principal Aquifers:** The exact number of primary and principal aquifers should be clarified and the aquifers within the potential development areas should be illustrated on a figure that identifies them clearly. Additionally, it is understood that these aquifers may possess pathways that would allow the groundwater to be impacted if a spill or leak were to occur. Engineering controls and practices are in place that can reduce the risk of impact to these aquifers during exploration and development. The SGIES should contain a discussion on the available mitigation measures and controls so that the potential impacts can be understood in context and intensity.
    - Section 2.4.4.1 Primary and Principal Aquifers (page 2-18)
    - Section 6.X (page 6-42)

  Within primary and principal aquifers, permit conditions require that if operations are suspended and the site is left unattended, pit fluids must be removed from the site immediately. It also states that after the cessation of drilling and/or stimulation operations, pit fluids must be removed within seven days. These timelines may be unnecessary or unachievable in certain cases. The DEC should work with operators to define additional mitigation measures regarding the construction or monitoring of pits that would allow for extensions to these timelines.
    - Section 7.1.3.2. Drilling Fluids (page 7-29)

AIR QUALITY

- **Air Modeling:** In many cases, the air modeling in the draft SGEIS uses a conservative approach that leads to some modeled violations of New York's very strict thresholds for air toxics. For modeling to meet short-term standards (24-hour and less), DEC assumed that all three operations, drilling, completion, and production can occur at the same time on a well pad. Completion activities cannot occur in the same wellbore while drilling is taking place. The assumption used should be clarified so that the more common practices, such as conducting only one activity at a time on any given well pad, are addressed. Calculations for emissions should be revised and the resulting calculations redone and shown for individual activities. However, even with this wrong assumption, the modeling showed compliance with all criteria pollutant air standards except for 24-hour $PM_{2.5}$. However, it seems that the background levels for $PM_{2.5}$ used in the analysis were "worst case" or at least a poor representation for the region. The background level assumptions should be revised to reflect a more realistic level. Also, to mitigate this $PM_{2.5}$ violation, it is suggested that a minimum stack height on all engines of 25 feet be used and a minimum separation distance to public access (fencing) from a well pad be 500 meters. The stack height is attainable; however, the 500 meter separation distance may not be achievable at all locations. The SGEIS needs to include other mitigation measures for $PM_{2.5}$ such as use of Diesel Particulate Filters (DPFs) or bio-fuels. Additionally, there would be cumbersome property owner information necessary to establish a public access separation; however, none of this information is required in the current version of the EAF addendum.

- Section 6.5.2.2 Sources of Air Emissions and Operational Scenarios (page 6-59).
- Section 6.5.2.3 Modeling Procedures (page 6-64)
- Section 6.5.2.4 Results of the Modeling Analysis (page 6-82).
- Table 6. 15 - Maximum Background Concentrations from DEC Monitor Sites (page 6-98)
- Table 6.17 - Maximum Project Impacts of Criteria Pollutants and Comparison to SILs, PSD Increments and Ambient Standards (page 6-100)
- Section 6.6.3 Emission Source Characterization (page 6-115)
- Section 7.5.3.1 Well Pad (page 7-89)

Additionally, the air model predicted annual methanol air emissions of 32.5 tons as possible at a central impoundment. If this prediction is correct, the 10 tons per year (tpy) threshold for one HAP as well as the 25 tpy threshold for combined HAPs would be exceeded thus requiring MACT controls and a site-specific SEQRA determination. Additional information is needed regarding this model prediction for methanol and identification of possible mitigation measure in lieu of MACT controls.

- Section 6.5.1.8 Potential Emission of Fracturing Water Additives from Surface Impoundments Methanol Air Emissions from Centralized Impoundments (page 6-57).

* **Greenhouse Gas Emissions:** The second Table 6.15 on page 6-126 titled Summary of Estimated Greenhouse Gas Emissions indicates that the total emissions in tons from proposed CO_2e for a 10-well project is 55,534 or 5,553 tons per well for an in-state source and 55,826 or 5,583 tons per well for an out-of-state source. Both of these emission estimates seem to be disproportionate in comparison to the 10-well pad GHG emission estimates of 12,005-12,110 tpy in-state and 16,024-18,129 tpy for out-of-state. The variable appears to be the amount of CH_4 expressed as CO_2e (1,500 tpy vs. 36,750 tpy). The difference in CH_4 is not explained adequately to derive a clear understanding of the analysis conducted to estimate the near 4.6 fold increase. Furthermore, these predicted estimates will exceed the 25 tpy threshold proposed by the EPA for GHGs.

Therefore, if correct, projects such as these would need to obtain construction and operating permits covering these emissions. Additionally, regarding the requirement for a GHG Mitigation Plan (in both Appendix 6 and 10), there is no mention of determining the estimated amount of emission reduction by pollutant.

- Section 6.6.10 Summary of GHG Emissions (p. 6-126).
- Appendix 6 Proposed Environmental Assessment Form Addendum
- Appendix 10 Proposed Permit Conditions

- **Regulatory Analysis:** The dSGEIS does not address details regarding the potential contributions of NO_X emissions, aggregation of oil and gas facilities, nor 40 CFR Part 63 Subpart ZZZZ. The NO_X emissions to the area's moderate 8-hour nonattainment classification are not discussed, and there is no photochemical modeling conducted. We recommend the addition of the following:

  1) A discussion addressing the mitigation measures used in the Barnett Shale play for the Dallas-Fort Worth moderate ozone nonattainment.
  2) A section explaining how the EPA's aggregation policy will be implemented in New York should be included.
  3) Finally, Appendix 17 should be augmented so that Subpart ZZZZ (Engine MACT) rule requirements are also included.

  - Section 6.5.1 Regulatory Analysis (p. 6-48)
  - Section 6.5.1 Regulatory Analysis (p. 6-48)
  - Appendix 17 Applicability of 40 CFR 63, ZZZZ

- **Flaring:** Short-term (12-24 hours) flaring can be necessary when the initial flowback has a high ratio of water to gas. The dSGEIS discusses operations in northern Pennsylvania, and states that gathering systems are constructed ahead of well completions to minimize flaring. In New York, the construction of gathering lines in conjunction with well pads may not always be possible; therefore, it may be advantageous to conduct long-term production testing (3 to 30 days) close to existing gathering lines to avoid the wasteful flaring of gas. The dSGEIS needs to address the potential for long-term production testing at a pad when gathering lines are not present.

  - Section 5.14, Well Cleanup and Testing (page 5-125)

- **Flowback Water Emissions:** Regarding the calculation of emissions (of chemical additives) from flowback water stored in impoundments, the second paragraph on page 6-79 states:

  "The use of these concentrations is deemed conservative to a certain extent since industry has noted that there is additional mixing with in-ground water as well as certain removal of the chemicals during hydraulic fracturing. However, these effects cannot be easily quantified and are likely balanced by other factors which could result in higher emissions."

The need for managing emissions from impoundments appears to be based on assertions rather than sound technical rationale. Mitigation measures required for managing potential emissions from impoundments should not be based on conservative assumptions. Regarding the statement*, "other factors could result in higher emissions"*; these "other factors" should be specifically stated. Also, the DEC should provide sufficient rationale to support the approach of ignoring the factors that reduce or remove concentrations of chemical additives from fracture fluids when calculating potential emissions from flowback water impoundments. Furthermore, these proposed requirements appear to be based on the assumption that the fracturing additive chemical composition is the same as the flowback water chemical composition, and do not take into account mixing of fracture fluids with formation water or removal of contaminants through the fracturing process.

- o Section 6.5.2.3 Air-Modeling Procedures (page 6-79)
- o Section 7.5.3.2 Centralized Flowback Water Surface Impoundments (page 7-90)

IMPOUNDMENTS

- **Permits:** The proposed use of a centralized flowback impoundment (CFI) is tied to the initial permit application for a well. This requirement seems subjective and inconsistent; the well permit is for the drilling and production of gas while the CFI is part of the waste management and requires a separate permit from the Department of Solid Waste. The permitting process in 6 NYCRR part 360-6 is intended for long-term waste facilities.

  Fracturing operations are typically temporary in nature and would have a much shorter life span then those facilities considered in part 360. Additionally, the CFI will most likely receive a separate SEQRA review. Therefore, CFIs are subject to multiple approvals. A streamlined approval process should be established that allows coordination between the various agencies and does not require duplicate permit applications and is commensurate with the temporary nature of the facility (i.e. less than six months). Also, for the purposes of recycling for beneficial reuse, consideration should be given to approval of the CFI to:

  1) fill the impoundment with water from any gas-related activity via truck or pipeline and

  2) treat and transport out via truck or pipeline.

  - o Section 7.1.7 Centralized Flowback Water Surface Impoundments (page 7-51)
  - o Section 7.7 Mitigation Impacts from Centralized Impoundments (page 7-95)

- **Construction:** The dSGEIS references operators who have constructed CFIs outside of New York and states that they typically include a leak detection device between two liners. We suggest that if the DEC intends to require similar construction and monitoring for CFI in New York, additional data should be provided on the monitoring requirements with possible discussion of acceptable devices (such as detection device and monitoring requirements, type, system, manufacturer, etc).

- Section 5.12.2.1 Centralized Storage of Flowback Water for Dilution and Reuse (page 5-115)

- **Dilution:** Compatibility mixing studies are suggested prior to actual blending with freshwater and at regular intervals throughout the year for seasonal variations. When a mixing study is conducted the results are assumed to be similar for all succeeding treatments involving similar compounds. Requiring a mixing study for every blending operation would be burdensome and possibly redundant. Furthermore, flowback water can vary based on reservoir properties and additive concentrations; therefore it is uncertain whether any useful data would be collected regarding seasonal variations from a limited number of samples at a particular pad, especially when varying fracture treatment compositions are used. Finally, compatibility would only be a concern when recycling these fluids, and since no discharge is allowed, it is unconceivable how this would affect regulatory requirements. Compatibility testing is therefore not necessary.
    - Section 5.12.2 Dilution (page 5-113)

- **Analytical Data:** Tables 5-8, 6.1 and 6.13 include laboratory quality control surrogate compounds as either part of the flowback fluid or fracturing fluid. These compounds should be removed from the tables. Furthermore, several operators have stated that the data provided to the DEC by them has not be used in its entirety or has been not been accurately represented, so that an accurate understanding of fracturing or flowback fluid might be obtained from the information presented in the dSGEIS. These tables should be updated with all the data provided by operators.
    - Section 5.11.3 Flowback Water Characteristics (page 5-103)
    - Section 6.1.3.2 Hydraulic Fracturing Additives (page 6-17)
    - Section 6.5.2.5 Conclusions (page 6-96)

- **Dam Safety Permitting:** The dSGEIS indicates that if a proposed impoundment exceeds the permitting threshold (height ≥ 15 feet, capacity ≥ 3M gallons) a Protection of Waters Permit issued by the Division of Environmental Permits would be required. As part of the permit requirements, a hydrologic investigation of the watershed and an assessment of the hydraulic adequacy of the proposed impoundment would need to be included with the Engineering Design Report. With regard to these requirements, the level of detail that would be needed for the investigation or assessment should be described or further detailed. Furthermore, no information is presented that addresses the conditions under which a draft EIS may be required. Also the term "the water dependent nature of a use" is used to describe the DEC's review, however that phrase seems unclear and indefinite. The discussion should be revised to clarify what is actually required and how it will be evaluated.

  Additionally, any Protection of Waters Permit for a location within the Adirondack Park requires that an appropriate application be submitted to the Adirondack Park Agency and the New York Department of Health, prior to submitting the application for the Protection of Waters Permit to the Division of Environmental Permits. Without this, the Dam Safety permit application is likely incomplete. Also, an EIS may be necessary as part of the Protection of Waters Permit process. These added steps need to be further addressed in the SGEIS and clear instructions provided so delays can be avoided and agency interactions are clearly understood.

  - Section 5.7.2.1 Protection of Waters-Dam Safety Permitting Process (page 5-81)

- **Freshwater Storage:** The dSGEIS references that a Protection of Waters Permit is required for storage structures greater than three million gallons. Given that pass-by flow conditions are based on the NFRM, water management plans will likely include the construction of large freshwater storage facilities. Current operations in northern Pennsylvania include multiple impounds up to 16 million gallons. Again the approval timeline for these types of impoundments needs to be commensurate with the proposed facility and construction requirements need to be well defined. Further, timelines to reclaim a freshwater impoundment should align with activity in an area as well as weather conditions and should not be for a set number of days. Finally, consideration should be given to allowing freshwater impoundments to be constructed within 100-year floodplains.

- **Reserve Pits:** Reclamation is stated as having to be completed within 45 days following the end of the drilling/stimulation operations. Operators may intend as part of their water management plan to use reserve pits to store flowback water and therefore would prepare a recycling plan. These pits could then be used to store and condition water in preparation for recycling on a subsequent fracture/treatment operation. Furthermore, for multiwell pad drilling, a 500,000-gallon restriction on the capacity of reserve pits is too small and consideration should be given to increasing this restriction to 2 million gallons. Larger reserve pits would promote water recycling. Also, flowback water should not have to be stored in steel tanks, as reserve pits would encourage water recycling. Pits are markedly more flexible and make it easier to condition, treat and ultimately recycle flowback water.

  - Section 5.11.2 Flowback Water Handling at the Wellsite (page 5-101)
  - Section 7.1.3 Surface Spills and Releases at the Well Pad (page 7-29)

- **Tanks:** The dSGEIS states that

  "… uncertainties relative to potential flowback water volume and composition have led the Department to propose that flowback water not be directed to an on-site reserve pit but instead be held on the well pad in tanks prior to shipment to a disposal, treatment or re-use location."

  This proposed requirement of not directing flowback water to an on-site reserve pit appears to contradict the proposed requirements outlined for impoundments. These proposed requirements also appear to be based on the assumption that the fracturing additive chemical composition is the same as the flowback water chemical composition, and do not take into account mixing of fracture fluids with formation water or removal of contaminants through the fracturing process. The DEC needs to clarify the requirements regarding on-site impoundments, and confirm the need for these mitigation measures using actual data from flowback water analyses.

  - Section 7.5.2 Mitigation Measure Resulting from Air Quality Impact Assessment (page 7-88)
  - Section 7.5.3.1 Well Pad (page 7-89)

- **Vegetation:** It is suggested that vegetation growing around the immediate edge of an impoundment be removed and the edge kept bare. This even applies to the soil used as liner ballast on the inside embankments because it could attract waterfowl to the impoundments resulting in possible exposure to the birds. If no vegetation is allowed to grow in the banks of the impoundment they will become denuded and promote erosion that would weaken the structure. This requirement should be removed, and other avian mitigation measures included.

  - Section 6.4.2 Centralized Flowback Water Surface Impoundments (page 6-48).

- **Testing:** The dSGEIS calls for the testing of flowback water so that it is "fully characterized" prior to permitting and injecting in a disposal well. It will be impossible to analyze for all compounds in the hydraulic fracturing additives for a variety of reasons including:

  - Certain proprietary compounds used as trade secrets are not disclosed and therefore cannot be analyzed,
  - Various compounds do not have an analytical test method, and
  - Numerous compounds are soluble salts or chemicals that undergo changes once placed into solution.

  Furthermore, it is unnecessary to fully characterize the water when it is being disposed of by injection into permitted Class II injection wells.

  Additionally, analytical test results from wells drilled in the same formation using the same hydraulic fracturing additives should be adequate for purposes of disposal. Table 17 in Appendix 22 uses the phrase "pollutant scan." There is no definition of this term, but it is assumed the DEC is referring to the priority pollutant compound lists and that the metals of concern are the priority pollutant metals list. If this is not the case, it should be clarified. In addition, the method for analyzing the metals should be reviewed considering that GFAA is outdated and there are many other methods available.

  - Section 7.1.8.2 Disposal Wells (page 7-60)
  - Appendix 22 NYSDEC - Division of Water Hydrofracturing Chemical (HFC) Evaluation Requirements for POTWs

ADDITIVES

- **Chemical Corrections:** Table 5-7 contains several errors that should be corrected in the final document:

  - D-Limonene is an aromatic compound.

- Cocamidopropyl Oxide is an amide.
- “Alkene” (CAS No. 64743-02-8) is listed twice, once in the miscellaneous and once in the petroleum distillates groups.
- “Triethylene glycol” and “Dipropylene glycol” are better classed as alcohols.
- “tetrakis” should be “Tetrakis (hydroxymethyl) phosphorium sulfate” (CAS No. 55566-30-8).
- Guar gum and Low mol wt polyacrylate are listed twice under polymers.
- “Hemicellulase” is listed twice under polymers also but the CAS No. is wrong on the second listing.
- Sodium hydroxide is also listed twice, once with an identified CAS Number and once without a CAS number.
- Trade name chemicals such as Exxal 13, Crissanol A-55, should be listed by their actual chemical name.
  - Section 5.4.3.1 Chemical Categories and Health Information, (page 5-53)

- **Heath Effects:** The health effects discussed following Table 5-7 do not include the complete toxicity information available, and do not account for the diluted nature of potential exposures. The following bullets provide suggested updates:
  - **Diluted Concentrations:** As demonstrated the fracturing fluids only contain < 2 percent additives; however the toxicity information provided appears to be based on <u>high-level exposures</u> rather than health effects that are from diluted concentrations.
  - **Exposure**: The discussion fails to state which types of exposure are more likely to occur. Most occupational studies for exposure identify dermal exposure as the primary route followed by inhalation and oral exposure in that order. The text seems to focus on inhalation and oral exposures at higher levels than are anticipated. This section should be revised to include a discussion of dermal exposure and should reflect reduced concentrations for the exposure potential.
  - **Petroleum Distillate Products:** The use of blistering to describe skin effects from kerosene is an overstatement. Also, in instance of accidental ingestion, an aspiration hazard should also be expected.
  - **Aromatic Hydrocarbons:** Again, the majority of exposures described as having hematological effects are associated with inhalation of high concentrations and the components of BTEX. . While such is the case with benzene, it is not the same for xylenes, ethyl benzene, or toluene. The more likely effects from these chemicals would be irritation upon skin contact and an aspiration hazard if ingested. These sections should be revised and clarified.
  - **Glycols:** Due to their low toxicity and volatility, glycols rarely pose an exposure issue unless ingested. This should be made clear in the document and the risk expressed appropriately.
  - **Glycol Ethers:** These compounds can cause skin irritation that is not discussed, and there are studies available regarding the potential for developmental effects that might also be referenced.

- **Alcohols:** In instances of alcohol exposure, effects can vary greatly. The text fails to mention skin irritation as the most likely effect, but rather focuses on the central nervous system.
- **Amides:** Skin irritation is overlooked again and the cumulative effects from exposure are not addressed.
- **Amines:** Skin irritation is not discussed nor are the concerns associated with the strong odors from amines mentioned. Again, the exposure is focused on ingestion and does not address dermal exposure. It should also be mentioned that some amines can be sensitizing agents.
- **Other Constituents:** Operators have reported that rather than as ingredients, 1,4-dioxane and formaldehyde appear as contaminants in surfactants and other additives from the manufacturer. Also, formaldehyde is a potential sensitizing agent. These and other compounds should be identified as possible contaminates and not as additives.
- **Conclusion:** The conclusions section should make clear that not all of the listed chemicals would be included in a single treatment or on a single well pad, and likewise should stress that potential exposures would more likely involve chemicals in a more diluted form or state. Furthermore, it should be emphasized that exposure would require an accident or catastrophic failure of controls, and that the health effects identified are <u>worst case scenario</u>s and do not represent the typical effects from daily activities. The risk potential should be placed in the proper context for frequency of exposure and intensity.
  - Section 5.4.3.1 Chemical Categories and Health Information (page 5-62)

- **Erroneous Additives:** Table 5-5 includes chemicals that have not been proposed for use in New York, and as such should not be listed. Table 5-6 identifies several examples of each type of additive in the list of constituents; this should be adequate.
  - Table 5-5 (page 5-42)
  - Table 5-6 (page 5-46)

- **Additive Approval:** The discussions in the dSGEIS conclude that adequate well design prevents contact between fracturing fluids and fresh groundwater sources, and there is also commentary on subsurface fluid mobility that explains why groundwater contamination by migration of fracturing fluid is not a reasonably foreseeable impact. There are also discussions of how setbacks, inherent mitigating factors and a myriad of regulatory controls protect surface waters. Hence, the only potential exposure pathways to fracturing additives identified by the dSGEIS are air emissions from uncovered surface flowback impoundments. The chemical analysis will determine the extent of required controls, including the distance within which ambient air thresholds are exceeded and public access must be restricted. However, the dSGEIS still proposes that the proposed volume of fracturing fluid and the percentage by weight of water of each additive be provided in the EAF addendum. What will be the procedure for altering the proposed fracturing fluid mixture if site conditions dictate a different approach? The dSGEIS needs to make clear what its authority will be with regard to additive use or approval.

- Section 3.2.2.1 Hydraulic Fracturing Information (page 3-8)
- Section 5.4 Fracturing Fluid (page 5-35)
- Section 6.5.2.3 Modeling Procedures (page 6-76)
- Section 7.1.8.1 Treatment Facilities (page 7-58)
- Section 7.5.2 Mitigation Measures Resulting from Air Quality Impact Assessment (page 7-88)
- Section 7.5.3.2 Centralized Flowback Water Surface Impoundments (page 7-90)
- Section 7.7 Mitigating Impacts from Centralized Flowback Water Impoundments (page 7-98)
- Section 8.2.1.2 Required Hydraulic Fracturing Additive Information
- Appendix 6 PROPOSED Environmental Assessment Form (EAF) Addendum
- Appendix 10 PROPOSED Supplementary Permit Conditions For High-Volume Hydraulic Fracturing

WELL SAMPLING

The dSGEIS states that operators will be required to identify all existing water supply wells within a half mile of the proposed pad location and provide information about the depth, completed interval, and use of each. Additionally, operators will be required to periodically sample the wells and take measurements of the static water levels.

The proposed water well testing schedule requires testing for the full suite of parameters during each testing event, however, the dSGEIS states that pH, TDS, barium, and total gross alpha activity will be initial indicators of contamination due to hydraulic fracturing. Accordingly, testing for the full suite of parameters at each testing event is more than what is necessary to protect groundwater users.

Consideration should therefore be given to requiring the full suite of parameters in only the initial (baseline) and final (one year follow-up) water well tests. Interim sampling should only include pH, TDS, barium, and total gross alpha activity (three and six months). It is also required that the initial water well testing be completed prior to site disturbance at the first well on the pad, and prior to drilling on subsequent wells on the pad. Coordinating testing of water wells prior to site disturbance for the first well adds unwarranted complexity to the well planning process and will provide no additional protection to groundwater resources. Additionally, if the value for total gross alpha activity exceeds 15 pCi/L it appears that additional analysis will be required. Since the testing is designed to establish and monitor baseline conditions, operators should not be encumbered with conducting additional radiological testing.

It should be noted that records of completion details for older domestic water supply wells are most likely not available, and the owners typically do not have well records, record maintenance histories, and often have not had their well surveyed to a benchmark. How does the DEC propose for operators to proceed with the analysis of changes in static water level when such information is not available? Without the well's construction, maintenance and operational history, any evaluation will be extremely difficult. The use patterns and recent precipitation and even the effects of other area wells may not be enough to draw valid conclusions. Furthermore, acquiring total well depth, screened intervals and static water level measurements will necessitate invasive techniques that could damage the wellhead, casing or pump, resulting in liability placed on the operators. Most domestic water supply wells are not constructed with observation ports to accommodate groundwater measuring equipment. Will the DEC provide coverage for any repair costs and will the DEC assure access to all sites to be tested by the operator? Also, to collect the static water level ,the well must be out of service for a period of time so the water level can equilibrate. Obtaining domestic well information may not be possible, is costly, and an unwarranted burden on the operator.

- Sections 3.2.2.4 Water Well Information (page 3-10)
- Section 7.1.4.1 Private Water Well Testing (page 7-41)

NATURALLY OCCURRING RADIOACTIVE MATERIALS **(NORM)**

- **Risk Assessment:** The dSGEIS mentions in various chapters that the Marcellus shale is known to contain NORM concentrations at higher levels than surrounding formations, and states that development and production activities have the potential to make the radium-226 more accessible to human contact and concentrate it through surface handling. The dSGEIS therefore states that disposal may need regulatory oversight to protect workers, the general public and the environment.

  The material presented regarding NORM is vague and not supported with adequate sample results. If NORM levels exceed applicable standards, the brine or equipment must be disposed of in a licensed facility, yet this circumstance is not discussed or acknowledged. Also, the text does not reference current DEC Cleanup standards that state that site cleanup must achieve levels of less than 10 mrem above background.

  These existing policies and procedures should be specifically referenced. Further, the US EPA has federal guidance and technical reports that express the current scientific and technical data for radiation risk assessments. The dSGEIS does not indicate whether EPA risk assessment criteria were applied to establish the exposure potential to NORM from drilling operations. The DEC should conduct the appropriate risk assessment for the Final SGEIS, and clearly describe the potential effects of Ra-226 and its exposure to the environment, workers, and the community.

    - Section 6.8 Naturally Occurring Radioactive Materials in Marcellus Shale (page 6-130)

- **Regulation:** The release of radioactive material into the environment is currently regulated by DEC. Part 380 (6 NYCRR Part 380 regulations) contains requirements for the discharge of NORM contained in brine and fracturing fluids, and effluent discharges are not allowed to exceed the radionuclide-specific values established in Part 380-11.7. For Ra-226, the limit is 6E-8 µCi/ml, or 60 pCi/L.

The dSGEIS indicates that discharges of effluents with radioactivity will need to be tested for NORM concentrations prior to release and that facilities possessing NORM wastes or used oil field equipment with elevated radiation levels may need a radioactive materials license. The DEC report published in April 1999 - "An Investigation of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Wells in New York State" acknowledges the practice of discharging produced water exhibiting elevated radionuclide levels from oil and gas producing formations and recognized these fluids as nonhazardous. If the DEC requires licensing and extensive testing it will be contradictory to its 1999 reported findings.

- Section 7.8.2 Regulation of NORM in NYS (page 7-103)

SOLID WASTES

- **Water Treatment:** The treatment of TDS waters results in the accumulation of solids as a secondary waste stream that requires disposal. The dSGEIS fails to address this issue and does not discuss any alternatives for the disposal of these wastes. There are typically only two options for disposal; landfill or underground injection. Landfill wastes are eventually released back into the environment via leachate. Additionally, the dSGEIS does not reference management protocols for solid or slurry materials generated during the treatment of high TDS waters. This topic should be addressed in its own section and information provided regarding existing handling practices and the appropriate disposal facilities available to operators in various counties.
  - Section 5.12 Flowback Water Treatment, Recycling and Refuse (page 5-112-119)
  - Section 5.13.4 Solid Residuals from Flowback Water Treatment (page 5-124)
- **Disposal:** The dSGEIS states that cuttings contaminated with oil based mud may not be disposed of on-site. There is no detail provided regarding the definition of "contaminated." There is a risk that some operators may make an extreme interpretation that contamination means any detectable concentration of oil and grease. The DEC should clarify the maximum allowable concentration of oil and grease in cuttings that is commensurate with environmental risk.

  Also, cutting volumes will likely increase with horizontal drilling and therefore the identification of alternative disposal options is needed. The recycling, reuse or even beneficial use of these materials is possible and represents an acceptable alternative to landfilling. Drilling mud is often recycled; the DEC should therefore consider the required recovery of oil based drilling mud and synthetic oil based drilling mud. There are remediation technologies that can reclaim this material and facilitate its reuse. A subsection of the recycling of mud should be added to the dSGEIS.

The injection of solids into the annulus would not be allowed pursuant to the dSGEIS; however, the impacts analysis in Chapter 6 does not address this practice. The DEC should provide a rationale for not allowing annular disposal of solid wastes as an option or remove the limitation.

- Section 6.1.9 Solids Disposal (page 6-40)
- Section 7.1.9 Solids Disposal (page 7-61)

WASTE TRANSFER

- **Record Keeping:** The recordkeeping requirements for production waste tracking have been borrowed from the State's current regulations for the disposal of medical waste. Manifesting of oil and gas generated wastes is not currently required by State law. It is proposed that a tracking form will be maintained by all operators and transporters of flowback water and produced brine, as well as the treatment or disposal facilities receiving the wastes. There is no explanation as to how this process is different from current requirements of waste haulers or why it is needed. A sample form should be included in the final SGEIS, as well as adequate details describing the reporting requirements or filing practices. Currently, haulers and receivers of flowback water and brine are required to use the "Waste Transporter Permit Renewal Notice" and application as outlined in Article 27, Titles 3 and 15 of the Environmental Conservation Law, and 6 NYCRR Part 364 and 6 NYCRR Part 381.

  Given the stringent existing reporting of waste haulers, the proposed tracking form seems redundant for disposal purposes. Furthermore, the tracking of flowback water designated for beneficial reuse would render it an industrial waste which would require the hauler to obtain a Waste Transporter Permit application for the same location that was already permitted. Details regarding the goal of this tracking form are needed so that the added requirements can be evaluated and detailed comments provided that address the costs and potential environmental benefits.

  - Section 7.1.6.1 Drilling and Production Waste Tracking Form (p. 7-50)
  - Section 7.1.6 Waste Transport (p. 7-50)

- **Transfer Permit:** It is unclear whether a permit would also be required for a centralized flowback water surface impoundment or collection tanks, and which DEC Division would be responsible for such. Pursuant to 6 NYCRR Part 360, it appears that a permit to operate the centralized flowback water surface impoundment or tanks would be required at each location. However, as the fluid would be considered a nonhazardous waste, the classification of the liquid is unclear as it relates to the permit requirements, variances and exemptions as expressed in 360-1.7.

- Further, under 360-1.7 (b)(4), it is stated that the transfer, temporary storage treatment, incinerator and processing facilities located at a single or multiple family residence, school, park, industry, hospital, commercial establishment, correctional facility, government facility or farm used exclusively for the management of solid waste generated at a location under the same ownership within a single region of the department is exempt from permitting to construct or operate a solid waste management facility or any phase of it. The DEC should not therefore create new requirements which would otherwise be inconsistent with 360-1.7.

- Section 7.1.6 Waste Transport (p. 7-51)

1,000-FOOT SEPARATION

The dSGEIS states in several provisions that a 1,000 foot separation is a significant distance; however, the document does not detail how this distance was derived and/or what scientific analyses were used to determine this measure. There is a reference to the original GEIS using this distance for requiring a SEIS, if a proposed well location is within 1,000 feet of a municipal water supply well and there are mentions of the 1,000 foot difference between the bottom of a potential aquifer and the target fracture zone.

The DEC should disclose the basis or data used to establish this distance. The definition of an aquifer should be clarified to eliminate any ambiguity for establishing this separation. Additionally, it should be clarified if the subsurface separation between an aquifer and target fracture zone is going to affect vertical fracture operations.

- Section 1.4.1 Generic Environmental Impact Statement (GEIS) (page 1-4)
- Section 6.1.5.2 Subsurface Pathways (page 6-37)

INVASIVE SPECIES

- **Survey:** As part of the EAF addendum a comprehensive invasive plant species survey is required. The dSGEIS does not identify the necessary qualifications of the individual tasked with conducting the survey nor does it state whether GIS data can be substituted for a map. The section should be revised to clarify these points. Alternatively, this requirement should be removed altogether - as other industries are not similarly required to conduct surveys prior to surface disturbing activities.
    - Section 3.2.2.7 Invasive Species Survey and Map (page 3-11)
- **Species List:** Not all of the species identified on Table 6-4 Terrestrial Invasive Plant Species in New York were identified on the New York Invasive Species Information web site (http://nyis.info/Default.aspx). The table could be updated with the current information.
    - Section 6.4.1.1 Terrestrial - Table 6.4 Terrestrial Invasive Plant Species In New York State (page 6-45)
- **Transfer:** There is insufficient rationale for requiring the management of invasive terrestrial species at HVHF sites. Section 7.4.1 outlines requirements for managing invasive species at HVHF sites. The rationale for this requirement is provided in Chapter 6, which states:

"The number of vehicle trips associated with high volume hydraulic fracturing, particularly at multi well sites, has been identified as an activity which presents the opportunity to transfer invasive terrestrial species."

Since the vast majority of increased traffic at HVHF sites are not engaged in ground disturbance or other activities that could lead to an increase in the distribution of invasive terrestrial species, there does not seem to be sufficient basis for requiring increased management of terrestrial invasive species at HVHF sites over what is required for other oil and gas sites. It should also be made clear that the risk of transferring invasive plants to an off-site location is the same or similar for all other construction projects.

- Section 6.4.1.1 Invasive Species-Terrestrial (page 6-46)
- Section 7.4.1.1. Invasive Species - Terrestrial (page 7-75)

- **Consultation:** The requirement to consult with the DEC's Division of Fish, Wildlife and Marine Resources prior to any ground disturbance at a site where invasive terrestrial species have been identified should be removed. The dSGEIS prescribes detailed handling and disposal requirements for invasive species; it is unclear what additional benefit consultation with the Division of Fish and Wildlife might provide. Requiring consultation introduces needless inefficiency into the site construction process and the potential for reduced clarity regarding management requirements.
  - Section 7.4.1.1. Invasive Species - Terrestrial (page 7-75)
- **Mitigation Plan:** The requirement for a site-specific invasive species mitigation plan is unnecessary. Given the limited number of species of concern listed in Chapter 6, and the prescribed management requirements set forth in Section 7.4.1.1, a generic invasive species mitigation plan that outlines management requirements given plant type should be sufficient.
  - Section 7.4.1.1. Invasive Species - Terrestrial (page 7-75)
- **Pits:** Pits are required to be lined and they are closed at the end of the project, therefore aquatic invasive species should not be a problem for pits. A discussion addressing the closing of pits and the low risk of transferring an aquatic species from these pits should be inserted into the document.
  - Section 6.4.1.2 Invasive Species-Aquatic (page 6-46)
- **Seeds:** The dSGEIS suggests that a native seed mixture be used when reclaiming a site. The DEC should assist in identifying suppliers and discuss how operators are to have their seed mixtures approved.
  - Section 7.4 Protecting Ecosystem and Wildlife (page 7-73)

VISUAL IMPACTS

The DEP-00-2 document, *Assessing and Mitigating Visual Impact*, addresses evaluating visual and aesthetic impacts generated from a proposed permanent facility. However, oil and gas operations are inherently temporary. The application of the definition of “permanent” to the natural gas industry is therefore arbitrary. Additionally, the requirement to inventory Aesthetic Resources within a five-mile radius as stated on page 3-15 in DEP-00-2 should be adequate to determine if a plan is required. If there are no resources noted, then no further mitigation should be required, as it is not cost effective or required to provide mitigation for non-permanent short term impacts.

- Section 6.9 Visual Impacts (page 6-131)

NOISE

Would a noise mitigation plan be required if a receptor is not within 1,000 feet of the operation? It would be arbitrary to assume that a noise mitigation plan is necessary in all rural areas, and it should be made clear when a noise mitigation plan would be required.

- Section 6.10 Noise (page 6-134)

TRUCK TRAFFIC

The Level of Service for any particular road needs to be evaluated using the method described in the 1994 Highway Capacity Manual. It does not appear that this method was used in the dSGEIS to assess the potential impacts from the increase in traffic from the temporary nature of oil and gas exploration and production. Based on the rural locations of the majority of proposed drilling, the increase in the truck traffic may, or may not, result in <u>any</u> significant impacts and therefore may not merit any mitigation measures. The Level of Service evaluations should be conducted for a number of roads and then the text revised to reflect the findings.

- Section 6.11 Road Use (page 6-138)

USE OF OTHER INDUSTRY REQUIREMENTS

The dSGEIS has identified various activities associated with HVHR that are represented as somehow equivalent to other industries, including:

- hazardous materials storage,
- radioactive materials disposal,
- storage of petroleum products,
- impervious surfaces,
- stormwater prevention plans,
- miscellaneous point sources, and
- solid waste disposal.

Due to this assumed comparability, several practices and regulatory processes are taken from non-oil and gas industrial activities and applied to natural gas activities. This approach does not recognize the unique characteristics of natural gas exploration, nor does it analyze these practices in context so their relevancy might be substantiated. The natural gas industry should not be burdened with regulatory regimes for which no real need has been demonstrated. Consideration should be given to removing these requirements or analyzing these requirements with respect to the desired outcome in relationship to the cost and perceived benefit.

- Section 7.1.12 Setbacks (page 7-64)
- Section 7.1.12.1 Setbacks from Ground Water Resources (page 7-66)

ENHANCED RESTRICTIONS

There are several enhanced requirements associated with proposed construction/completion techniques for HVHF in the dSGEIS under supplemental permit conditions. Much of these seem to be "regulations for regulations' sake." The dSGEIS does not detail the technical rationale for these enhanced requirements in contrast to standard practices accepted in the industry and in use in other areas, or as compared to vertical hydraulic fracturing operations throughout the state. A practical, environmental or safety benefit should be identified as the goal for requiring enhanced procedures before these are proposed and that the procedures are needed to address a problem or concern. Consideration should be given by the DEC to reevaluating these enhanced requirements, and the perceived goals or benefits should be identified prior to including them in the Final SGEIS.

- Section 7.1.4.2 Sufficiency of As-Built Wellbore Construction – Surface Casing Cement (page 7-45)

SECONDARY CONTAINMENT

The SGEIS suggests that secondary containment is required for all tanks above 10,000 gallons containing flowback water. The preferred method is to store flowback water in reserve pits or CFI; however there will invariably be the need to hold flowback water in 21,000 gallon portable temporary steel storage tanks. These tanks are transported to the site and would obviate any secondary containment established over ground. Therefore, the only feasible way to add secondary containment would be to put a liner underground on the pad and build a berm around the entire site. This could result in pad E&S issues – such as rain water not being allowed to escape from the site. This would add substantial and unnecessary cost, as currently using portable steel temporary storage tanks has proven to be a reliable method for containment of flowback water. Gross flowback storage tanks are made up of multiple 21,000 portable steel temporary storage tanks, so the discharge of 100 percent of the flowback water is therefore not conceivable. No secondary containment should be required for on-site temporary "wheelie tanks".

- Section 7.1.12.2 Setback From Surface Water Resources (page 7-70)

FLOODPLAINS/WETLANDS

The provisions relating to floodplains and wetlands require the use of a closed-loop tank system, instead of a reserve pit for managing fluids and cuttings when drilling within these designated areas. Also CFI and associated above-ground piping and conveyances will not be allowed in floodplains or wetlands. Furthermore, the additional measures mentioned do not state where fracture-tanks can be placed in proximity to wetlands.

There are mitigation measures that can be used that will allow for the safe operation of drilling activities, and reduce or eliminate the potential impacts. Given that these potential impacts can be mitigated, consideration should be given to issuing permits without special conditions for drilling activities in these areas as long as all requirements are met. These sections could benefit from added mitigation descriptions for floodplains and wetlands. Also, the anticipated setbacks for flowback tanks from wetlands, as well as when secondary containment controls are needed, should be included in the revised discussion.

- Section 6.2 Floodplains (p-6-42)
- Section 7.2 Protecting Floodplains (p. 7-72)
- Section 7.3 Protecting Freshwater Wetlands (p. 7-73)

IMPACT CONTEXT

There are a number of instances in Chapter 6 where the impacts are not placed in the appropriate context with respect to other industries with similar impacts. The text seems to represent that only the natural gas industry would cause the impacts described. The impacts are often presented in a perjorative light, so as to represent that the environmental resource would experience irrecoverable damage. Examples of these descriptions follow:

- Section 6.1.1.1 Reduced Stream Flow (page 6-4). The narrative does not illustrate that <u>any</u> withdrawal of water, including future and existing withdrawals, contributes to the overall impact of the stream flow. It should recognize that all withdrawals, not only the withdrawals associated with natural gas development, add to the types of impacts described.

- Section 6.1.1.2 Degradation of a Stream's Best Use (page 6-4). This section seems to focus on quantity as the basis behind a stream's best use and forgoes mentioning quality. A stream's best use relies on both quantity and quality.

- Section 6.1.1.3 Impacts to Aquatic Habitat (page 6-5). The discussion is overly conservative and does not place the withdrawal of water in the appropriate context with regards to flow and pass by allowances. A discussion regarding the stability that is achievable between water utilization and the needs of the environment would be more appropriate.

- Section 6.1.1.4 Impacts to Aquatic Ecosystem (page 6-5). The use of the phrase "changes in water quantity and quality" does not place these terms in context with what is perceived as acceptable or unacceptable changes. A better description is needed so the reader can understand the depth or significance of the potential impacts.

- Section 6.1.1.5 Impacts to Downstream Wetlands (page 6-6). Again the text is overly conservative and does not place the impacts in the appropriate context. Water can be withdrawn from wetlands in quantities that will not result in irreversible impacts. Again, a discussion regarding the stability that is achievable between water utilization and the needs of the environment would be well served here.

- Section 6.1.1.6 Aquifer Depletion (page 6-6). Again, more overly conservative discussion is used here that implies that all water use results in depletion and therefore no water use should be approved. Recognition of the hydrologic cycle of water, including precipitation, recharge, and use seems to have been forgone with regards to the out-of-basin-transfer discussion. The section could benefit from a fuller description of the cycle and the uses, versus annual recharge.
- Section 6.1.1.7 Cumulative Water Withdrawal Impacts (page 6-7). Again, this discussion seems to negate the fact that there are other uses of water besides the natural gas industry. The impacts should be described as resulting from the overall withdrawal of water -- including new and existing users. Also, the text does not illustrate that the natural gas industry recycles and treats a tremendous amount of water that is then returned to the system; rather it appears to characterize the industry as only a consumer. Additionally, the natural gas industry tends to use water early in the development process and then reduces its use as the fields are developed. This was not made clear in the discussion; rather the industry is portrayed as a more permanent user.

RECLAMATION

Well pads are required to be reclaimed. In some cases, a landowner may request that reclamation and re-contouring is unnecessary or simply unwanted. DEC should have exemptions for cases where a landowner agrees that reclamation and re-contouring is unnecessary or unwanted.

- Section 7.9.3 Reclamation (page 7-105)

GENERAL

- **Multiple Permits:** There are now multiple permits required for HVHF, with the issuance of some permits dependent on the operator having already received another permit(s). Without DEC commitment to completing these permits within a specified timeline, the cost and uncertainty associated with approvals could very easily prevent development from occurring in New York. DEC must ensure that adequate resources are applied to its internal permitting groups. Consideration should be given to conducting the permit approvals in a parallel process - rather than in series - and defined milestone dates for approvals should be included.
- **New York City Watershed:** The 1992 GEIS contains proposed mitigation measures that are sufficient and have been demonstrated to achieve the desired benefits. However, when a well is proposed within close proximity to the NYC watershed or some other special area, a more stringent requirement is proposed. It seems that these areas are receiving enhanced treatment without the benefit of technical analysis to support the more stringent requirements. Furthermore this could establish a standard that might

later be applied to other watersheds or unique areas. We believe that all development should be treated equally unless a unique characteristic can be demonstrated that places that area at higher risk to impact.

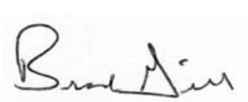
- **Shale Gas Requirements:** The requirements proposed for shale gas development are more stringent than the existing requirements in practice for other formations. This difference establishes a hierarchy within the state as to how these formations are managed. By implementing these new requirements for development of the Marcellus Shale and other similar unconventional shale reservoirs, an inconsistent approach is created for assiduous management of other gas development operations. This could affect the economic practicality of developing shale gas or low-permeability gas reservoir wells and make it unreasonable to develop marginal wells. This could result in much-needed natural gas reserves being undeveloped due to the prohibitive associated cost.

IOGANY recognizes that in drafting the dSGEIS, the NYSDEC has attempted to strike a balance between responsible energy development and environmental stewardship. However, certain aspects of the dSGEIS appear to be cumbersome to implement and very awkward to manage.

The proposed mitigations (such as domestic water well testing, cementing inspections, multiple permits, etc) will require considerable resources within the DEC and associated government agencies. It must be acknowledged that the viability of shale gas development in New York relies heavily on the ability of operators to carefully plan, coordinate and execute operations. Additionally, delays or uncertainty in the regulatory process will have a significant negative impact on economic development in the State.

We appreciate the opportunity to provide these comments and look forward to reviewing the Final SGEIS. Should you have a question or need additional information in this regard, please do not hesitate to contact me at 716-627-4250 or brgill@iogany.org

Respectfully submitted,



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